EB-2012-0167

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Thunder Bay Hydro Electricity Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

BEFORE: Cynthia Chaplin
Presiding Member and Vice Chair

Ellen Fry
Member

DECISION AND ORDER

April 18, 2013

Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay Hydro") filed an application with the Ontario Energy Board (the "Board") on November 9, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Thunder Bay Hydro charges for electricity distribution, to be effective May 1, 2013.

The Board issued a Notice of Application and Hearing on December 3, 2012. The School Energy Coalition ("SEC"), Energy Probe Research Foundation ("Energy Probe"), the Vulnerable Energy Consumers Coalition ("VECC") and the Association of Major Power Consumers in Ontario ("AMPCO") applied for and were granted intervenor status and cost eligibility.

Pursuant to the Board's procedural orders, Thunder Bay Hydro filed its interrogatory and supplemental interrogatory responses on February 22, 2013 and March 25, 2013 respectively. The intervenors and Thunder Bay Hydro (collectively, the "Parties") participated in a Settlement Conference convened on April 2, 2013 and reached a complete settlement on all matters. The Proposed Settlement Agreement ("Settlement Agreement") was filed on April 16, 2013 and is included as Appendix A to this Decision and Order.

The Board commends the Parties on achieving settlement of all matters. Having reviewed the Settlement Agreement, the Board accepts it in its entirety.

The Board wishes to remind the Parties that the individual elements of a settlement agreement do not create a precedent for the Board.

Parties to the Settlement Agreement agreed that the new rates should be effective May 1, 2013 with the stipulation that Thunder Bay Hydro be allowed to recover any forgone revenue ensuing from any delay in the issuance of the Rate Order. The Board will declare Thunder Bay Hydro's existing rates interim effective May 1, 2013.

The Board reminds Thunder Bay Hydro that the following matters are to be incorporated into the Tariff of Rates and Charges that is to accompany the draft Rate Order.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013.

Wholesale Market Service Rate

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013.

Smart Metering Entity Charge

On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors*. This charge will be in effect from May 1, 2013 to October 31, 2018.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. The Board declares Thunder Bay Hydro's existing rates interim, effective May 1, 2013.

2. The oral hearing scheduled for April 25 and 26, 2013 is cancelled.

3. Thunder Bay Hydro shall file with the Board, and also send to intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision **by April 24, 2013**. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

4. Board staff and intervenors shall file any comments on the draft Rate Order with the Board and send to Thunder Bay Hydro by **April 29, 2013**.

5. Thunder Bay Hydro shall file with the Board and send to intervenors responses to any comments on its draft Rate Order by **May 2, 2013**.

Cost Awards

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice

Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

1. Intervenors shall file with the Board and send to Thunder Bay Hydro their respective cost claims within **7 days** from the date of issuance of the Rate Order.

2. Thunder Bay Hydro shall file with the Board and send to intervenors any objections to the claimed costs within **17 days** from the date of issuance of the Rate Order.

3. Intervenors shall file with the Board and send to Thunder Bay Hydro any responses to any objections for cost claims within **24 days** of the date of issuance of the Rate Order.

4. Thunder Bay Hydro shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number, EB-2012-0167, and be made through the Board's web portal at www.pes.ontarioenergyboard.ca/service/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca . If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca . All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

DATED at Toronto, April 18, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Board File No: EB-2012-0167

DATED: April 18, 2013

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April 16, 2013

DELIVERED BY RESS, COURIER AND E-MAIL

Ms. Kristen Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Proposed Settlement Agreement
Thunder Bay Hydro Electricity Distribution Inc. 2013 COS Application
EB-2012-0167

We are counsel to Thunder Bay Hydro Electricity Distribution Inc. in respect of the above noted mater. Pursuant to Procedural Order No. 2, please find enclosed a proposed Settlement Agreement in respect of this matter. As noted in the attached, a complete settlement has been reached on all issues in this proceeding.

Pursuant to Section 1.4 of the proposed Settlement Agreement, the Parties accept that the appropriate effective date of the new rates flowing from this Application is May 1, 2013. In the event the Board is unable to approve a final rate order in time for Thunder Bay to implement new rates for May 1, 2013, the Parties agree that Thunder Bay's existing rates should be charged on an interim basis and upon Board approval of a final rate order Thunder Bay will be entitled to charge a rate rider over the remaining balance of 2013 calendar year to recover any foregone revenues between May 1, 2013 and the date Thunder Bay implements the new rate order.

Yours Truly,

BORDEN LADNER GERVAIS LLP

Original signed by John A.D. Vellone

John A.D. Vellone

Encl.

Copy: Robert Mace and Cindy Speziale, Thunder Bay Hydro Electricity Distribution Inc.
All Parties in EB-2012-0167 (By e-mail only)

EB-2012-0167

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Thunder Bay Hydro Electricity Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. ("THUNDER BAY")

SETTLEMENT AGREEMENT

FILED: APRIL 16, 2013

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<u>Appendices:</u>

EB-2012-0167

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Thunder Bay Hydro Electricity Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. ("THUNDER BAY")

SETTLEMENT AGREEMENT

FILED: APRIL 16, 2013

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INTRODUCTION:

Thunder Bay carries on the business of distributing electricity within the City of Thunder Bay as described in its distribution licence.

Thunder Bay filed an application with the Ontario Energy Board (the "Board") on November 9, 2012 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes to the rates that Thunder Bay charges for electricity distribution, to be effective May 1, 2013 (the "Application"). The Board assigned the Application File Number EB-2012-0167.

Four parties requested and were granted intervenor status: Energy Probe Research Foundation ("Energy Probe" or "EP"), the Vulnerable Energy Consumers' Coalition ("VECC"), School Energy Coalition ("SEC"), and the Association of Major Power Consumers in Ontario ("AMPCO"). These parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on January 9, 2013, the Board approved the Intervenors in this proceeding, set dates for interrogatories and interrogatory responses and made its determination regarding the cost eligibility of the Intervenors.

In Procedural Order No 2, issued on March 5, 2013, the Board set dates for supplementary interrogatories and interrogatory responses; and dates for a Settlement Conference (April 2, 2013, continuing April 3, 2013 if necessary); and, the filing of any Settlement Proposal arising out of the Settlement Conference (April 16, 2013). There is no Board-approved Issues List for this proceeding.

The evidence in this proceeding (referred to herein as the "Evidence") consists of the Application and Thunder Bay's responses to the initial and supplemental interrogatories. The Appendices to this Proposed Settlement Agreement (the "Agreement") are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 2, with Mr. Andrew Diamond as facilitator. The Settlement Conference was held on April 2 and 3, 2013.

Thunder Bay and the following Intervenors participated in the Settlement Conference:

- Energy Probe;
- SEC;
- VECC; and
- AMPCO.

Thunder Bay and the Intervenors are collectively referred to below as the "Parties".

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "Guidelines"). The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

The role adopted by Board Staff in the Settlement Conference is set out in page 5 of the Guidelines. Although Board staff is not a party to this Agreement, as noted in the Guidelines, Board staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

A COMPLETE SETTLEMENT HAS BEEN REACHED ON ALL ISSUES IN THIS PROCEEDING:

The Parties are writing to advise the Board that a complete settlement has been reached on all issues in this proceeding. This document comprises the Proposed Settlement Agreement and it is presented jointly by Thunder Bay, Energy Probe, SEC, VECC and AMPCO to the Board. It identifies the settled matters and contains such references to the Evidence as are necessary to assist the Board in understanding the Agreement. The Parties confirm the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties agree the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request the Board consider and accept this Proposed Settlement Agreement as a package - none of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Agreement. The distinct issues addressed in this proposal are intricately interrelated and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement in its entirety, then there is no Agreement unless the Parties agree that those portions of the Agreement the Board does accept may continue as a valid settlement.

It is further acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the *Board's Rules of Practice and Procedure*.

It is also agreed that this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2013 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices to the Agreement provide further evidentiary support. The Parties agree this Agreement and the Appendices form part of the record in EB-2012-0167. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement. Appendix I to this Agreement – Proposed Schedule of 2013 Tariff of Rates and Charges (Updated) – is a proposed schedule of Rates and Charges. If the Board approves the Agreement Thunder Bay expects to use the information in Appendix I as the basis for its draft Rate Order following Board approval of this Agreement.

The Parties believe the Agreement represents a balanced proposal that protects the interests of Thunder Bay's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Thunder Bay to manage its assets so that the highest standards of performance are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met.

The Parties have agreed the effective date of the rates resulting from this proposed Agreement is May 1, 2013 (referred to below as the "Effective Date").

ORGANIZATION AND SUMMARY OF THE SETTLEMENT AGREEMENT:

As noted above, there is no Board-approved Issues List for this proceeding. For the purposes of organizing this Agreement, the Parties have used the Issues List in the Guelph Hydro Electric Systems Inc. proceeding (EB-2011-0123) as a guide, as that Issues List addresses all of the revenue requirement components, load forecast, deferral and variance account dispositions, cost allocation and rate design and other issues that are also relevant to determining Thunder Bay's 2013 distribution rates.

The following Appendices accompany this Settlement Agreement:

Appendix A – Summary of Significant Changes
Appendix B – Continuity Tables (Updated)
Appendix C – Cost of Power Calculation (Updated)
Appendix D – 2013 Customer Load Forecast (Updated)
Appendix E – 2013 Other Revenue (Updated)
Appendix F – 2013 PILS (Updated)
Appendix G – 2013 Cost of Capital (Updated)
Appendix H – 2013 Revenue Deficiency (Updated)
Appendix I – Proposed 2013 Schedule of Rates and Charges (Updated)
Appendix J – 2013 Updated Customer Impacts (Updated)
Appendix K – Cost Allocation Sheets O1 (Updated)
Appendix L – Revenue Requirement Work Form (Updated)
Appendix M – Throughput Revenue (Updated)

UNSETTLED MATTERS:

There are no unsettled matters in this proceeding.

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow Thunder Bay to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

The Parties agree no rate classes face bill impacts that require mitigation efforts as a result of this Agreement.

In this Agreement, except where otherwise expressly stated, all dollar figures are calculated and expressed using Modified Canadian Generally Accepted Accounting Principles ("MCGAAP") as more fully described at Exhibit 1, Tab 2, Schedule 1, Page 5 of the Application. For the purposes of settlement, the Parties acknowledge that Thunder Bay is not converting to International Financial Reporting Standards ("IFRS") in the 2013 Test Year and intends to remain on MCGAAP until required by the Accounting Standards Board (the "AcSB") or until Thunder Bay otherwise elects to move to IFRS. However, Thunder Bay has complied with the Board's letter titled "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies 2013" dated July 17, 2012. Thunder Bay has implemented the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2013. As a result of these changes, Thunder Bay expects that there will be no material adjustments when Thunder Bay ultimately converts to IFRS.

In Thunder Bay's initial evidence (Exhibit 3, Tab 1, Schedule 1, Page 1) the Service Revenue Requirement for the 2013 Test Year was $21,652,791 which included a Base Revenue Requirement of $19,901,055 and Revenue Offsets of $1,751,736 with a resulting Revenue Deficiency (Exhibit 6, Tab 1, Schedule 2, Page 1) of $1,559,334.

Through the interrogatory and settlement process, Thunder Bay made changes to the Service Revenue Requirement as shown in Settlement Table #1: Service Revenue Requirement as follows:

Settlement Table #1: Service Revenue Requirement

		COS Application Filing	Settlement Submission	Difference
Service Revenue Requirement	**A**	$ 21,652,791	$ 20,988,613	$ (664,178)
Revenue Offsets	**B**	$ (1,751,736)	$ (1,778,000)	$ (26,264)
Base Revenue Requirement	**C= A+B**	$ 19,901,055	$ 19,210,613	$ (690,442)
Revenue at Existing Rates	**D**	$ 18,341,720	$ 18,473,376	$ 131,655
Revenue Deficiency	**E=C-D**	$ 1,559,334	$ 737,237	$ (822,097)

The revised Service Revenue Requirement for the 2013 Test Year is $20,988,613 which reflects the updated cost of capital parameters (ROE and Deemed Short Term Debt rate) issued by the Board on February 14, 2013 applicable to applications for rebasing effective May 1, 2013. The long term debt rate was agreed to be 1.53%, for the purpose of settlement. Compared to the forecast 2013 revenue at current rates of $18,473,376 the revised Service Revenue Requirement represents a revenue deficiency of $737,237 which is a $822,097 reduction from the original revenue deficiency of $1,559,334 set out in Exhibit 6, Tab 1, Schedule 2, Page 1 in the Application.

Through the settlement process, Thunder Bay has agreed to certain adjustments from its original 2013 Application and subsequent updated Evidence. Any such changes are described in the sections below.

1. GENERAL

1.1 Has Thunder Bay responded appropriately to all relevant Board directions from previous proceedings?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 1, Tab 1, Schedule 15

For the purposes of settlement the Parties accept the Evidence of the Applicant that there were no outstanding obligations or orders from previous Board decisions.

1.2 Are Thunder Bay’s economic and business planning assumptions for 2013 appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 1, Tab 2, Schedule 2

For the purposes of settlement, the Parties accept Thunder Bay’s economic and business planning assumptions for 2013, are appropriate.

1.3 Is service quality, based on the Board specified performance assumptions for 2013, appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 2, Tab 3, Schedule 5, Exhibit 2, Appendix 2-D
Board Staff IR#7 (Appendix 2-D)
AMPCO IR#8 (Appendix 2-D)

For the purposes of settlement, the Parties accept Thunder Bay's evidence with respect to the acceptability of its service quality, based on the Board-specified indicators.

1.4 What is the appropriate effective date for any new rates flowing from this Application? If that effective date is prior to the date new rates are actually implemented, what adjustments should be implemented to reflect the sufficiency or deficiency during the period from effective date to implementation date?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 1, Tab 1, Schedule 2

For the purpose of settlement, the Parties accept that the appropriate effective date of the new rates flowing from this Application is May 1, 2013.

In the event the Board is unable to approve a final rate order in time for Thunder Bay to implement new rates for May 1, 2013, the Parties agree that Thunder Bay's existing rates should be charged on an interim basis and upon Board approval of a final rate order Thunder Bay will be entitled to charge a rate rider over the remaining balance of 2013 calendar year to recover any foregone revenues between May 1, 2013 and the date Thunder Bay implements the new rate order.

2. RATE BASE

2.1 Is the proposed rate base for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 2, Tab 1, 5, Schedule 2,4
AMPCO IR#5
Energy Probe IR#3, Supplemental IR#20s-22s
SEC IR#3
VECC Supplemental IR#48s

For the purposes of settlement, the Parties have agreed that Thunder Bay's amended forecast Rate Base of $93,339,122 for the 2013 Test Year under MCGAAP is appropriate. A full calculation of this agreed Rate Base is set out in Table #2: Rate Base below. The calculation of the 2013 rate base has been updated to reflect the closing 2012 rate base, based on actual capital closed to rate base in 2012.

Settlement Table #2: Rate Base

		COS Application Filing	Supplemental Interrogatory Adjustments	Supplemental Interrogatory Response	Settlement Adjustments	Settlement Agreement
Average Gross Fixed Assets	**A**	$ 174,982,258	$ (1,036,564)	$ 173,945,694	$ 55,000	$ 173,890,694
Average Accumulated Deprecia	**B**	$ (95,076,084)	$ 211,065	$ (94,865,019)	$ (566)	$ (94,864,453)
Average Net Fixed Assets	**C= A+B**	$ 79,906,174	$ (825,499)	$ 79,080,675	$ 54,434	$ 79,026,241
Allowance for Working Capital	**D**	$ 14,487,107	$ (262,804)	$ 14,224,303	$ (88,578)	$ 14,312,881
Total Rate Base	**E=C+D**	$ 94,393,281	$ (1,088,303)	$ 93,304,978	$ (34,144)	$ 93,339,122

2.2 Is the working capital allowance for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 2, Tab 4, Schedule 1
Energy Probe IR#9

For the purposes of settlement, the Parties agree to a Working Capital Allowance of $14,312,881 calculated based on 13% of the settled upon OM&A expenses of $14,300,000 (MCGAAP including property tax and excluding depreciation included in the OM&A numbers) and Cost of Power of $96,062,657.

The Parties agree the adjustments shown below in Settlement Table #3: Allowance for Working Capital, reflecting the settled matters as summarized elsewhere in this Proposed Settlement Agreement, will be made to Thunder Bay's Working Capital Allowance calculation:

Settlement Table #3: Allowance for Working Capital

		COS Application Filing	Supplemental Interrogatory Adjustments	Supplemental Interrogatory Response	Settlement Adjustments	Settlement Agreement
OM&A Expenses	**A**	$ 14,682,415	$ 4,877	$ 14,687,292	$ (387,292)	$ 14,300,000
Less: Amortization included above	**B**	$ (263,569)		$ (263,569)		$ (263,569)
Cost of Power	**C**	$ 97,020,439	$ (2,026,446)	$ 94,993,993	$ 1,068,664	$ 96,062,657
Working Capital Base	**D=A+B+C**	$ 111,439,285	$ (2,021,569)	$ 109,417,716	$ 681,372	$ 110,099,088
Working Capital Allowance	**E=D*13%**	$ 14,487,107	$ (262,804)	$ 14,224,303	$ 88,578	$ 14,312,881

2.3 Is the capital expenditure forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 2, Tab 3, Schedule 1
Board Staff IR# 4 Supplemental IR#46s,47s
AMPCO IR#6,7 Supplemental IR#35s
Energy Probe IR#5,6,7 Supplemental IR#24s
VECC IR#1,3, Supplemental IR#49s

For the purposes of settlement, the Parties accept net capital expenditures of $13,239,139[1]- as amended from Thunder Bay's original Application of $12,372,305[2] and reflecting, *inter alia*, the deferral of the truck with the single bucket purchase as per Thunder Bay's response to 2-EP-6 and as further amended to reflect settlement. The resulting continuity schedules are shown in Appendix B.

The following is for information purposes and provides a reconciliation of the capital asset changes:

	Original Application	Interrogatory Adjustments	Net Change	Supplemental Interrogatory Adjustments	Net change	Settlement Agreement	Net Change
2012							
Total Additions	8,836,615	9,132,744	296,129			9,132,744	0
Add: Opening WIP	2,950,259	2,950,259	0				
Less: Closing WIP	(1,268,794)	(3,204,185)	(1,935,391)				
WIP Change	1,681,465	(253,926)	(1,935,391)			(253,926)	0
	10,518,080	8,878,818	(3,574,653)			8,878,818	0
Less ARO Additions	0	(137,886)	(137,886)			(137,886)	0
	10,518,080	8,740,932	(3,712,539)			8,740,932	0
Net Capital Asset		(1,639,262)					
WIP		1,935,391					
		296,129					
2013							
Total Additions	12,132,192			11,473,031	(659,161)	11,363,031	(110,000)
Add: Opening WIP	1,268,794			3,204,185	1,935,391	3,204,185	
Less: Closing WIP	(983,556)			(1,282,952)	(299,396)	(1,282,952)	
WIP Change	285,238			1,921,233	1,635,995	1,921,233	0
	12,417,430			13,394,264	976,834	13,284,264	(110,000)
Less ARO Additions	(45,125)			(45,125)	0	(45,125)	0
	12,372,305			13,349,139	976,834	13,239,139	(110,000)
Infrastructure Capital net of Contributed Capital				1,206,834		(110,000)	
WIP				(1,635,995)		0	
Part C-Single Bucket Truck				(230,000)		0	
				(659,161)		(110,000)	

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[1] This amount is calculated as $11,363,031, as per Appendix B, plus the change between the updated opening and closing 2013 WIP of $1,921,233 less the $45,125 ARO addition as further amended to reflect settlement.
[2] This amount is calculated as $12,132,192, per Table 2-5.1-Fixed Asset Continuity Schedule at Exhibit 2, Tab 5, Schedule 1, plus the change between opening and closing 2013 WIP of $285,238 less $45,125 ARO addition.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 2, Tab 3, Schedule 4 Application: Exhibit 2, Tab 5, Schedules 1-4 Energy Probe Supplemental IR# 23s VECC IR#34

For the purposes of settlement, the Parties accept Thunder Bay's capitalization policy as it was set out in Exhibit 2, Tab 3, Schedule 4 of the Application and the impacts as set out in Exhibit 2, Tab 5, Schedules 1-4 of the Application.

3. LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 3, Tab 2, Schedule 1
Board Staff IR#11,12a,b,d,13a,c, 14a,b,c,e Supplemental IR#50s, 52s, 51s
VECC IR#7, 8, 9,10, 12, 14, 16 Supplemental IR#52s, 53s
Energy Probe Supplemental IR#25s

For the purposes of settlement, the Parties accept Thunder Bay's load forecast methodology, including weather normalization, as modified through the interrogatory responses and settlement process as follows:

- Changes to the load forecast for the purposes of settlement, included the CDM manual adjustment from gross to net based on the 2011 Final OPA program results. The adjustment also reflects a half year being applied to 2011 programs persisting into 2013, a full year of 2012 programs persisting into 2013 along with the half year rule being applied to 2013 programs.

This results in a billed consumption forecast of 956,387,714 kWh and 1,384,348 kW in the 2013 Test Year. The accepted CDM adjustment for 2011, 2012 and 2013 CDM programs is 10,797,875 kWh and 15,630 kW for the 2013 Test Year.

3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 3, Tab 2, Schedule 1 Board Staff IR#11 Supplemental IR#54s Energy Probe IR#10 VECC IR#13

For the purposes of settlement, the Parties agree that the 2013 customer forecast will be revised by adjusting for each customer class, the 2013 forecast by an amount equal to the difference between the 2012 customer forecast included in the Application for such class and the actual number of customers for such class in 2012.

With respect to the load forecast, for the purposes of settlement, the Parties agree to modify the movement of the CDM manual adjustment from gross to net consumption. The changes made to the consumption for all classes reflect the CDM manual adjustment from gross to net consumption, and also reflects the discussion under Section 3.1 above. Settlement Table #4: Load Forecast, details the above changes. Appendix D reflects the revised load forecast.

Settlement Table #4: Load Forecast

	Initial Application	Settlement Adjustment	Settlement Agreement
Residential			
Customers	45,158	-277	44,881
kWh	335,941,782	3,779,280	339,721,062
General Service < 50 kW			
Customers	4,330	162	4,492
kWh	129,942,565	1,461,829	131,404,394
General Service > 50 to 999 kW			
Customers	507	7	515
kWh	285,190,036	3,208,333	288,398,369
kW	774,872	8,717	783,589
General Service > 1000 kW			
Customers	19	0	19
kWh	181,491,144	2,041,740	183,532,884
kW	562,588	6,329	568,917
Streetlights			
Connections	13,180	37	13,217
kWh	11,059,201	124,414	11,183,615
kW	31,152	350	31,502
Sentinel Lights			
Connections	151	18	169
kWh	121,120	1,363	122,483
kW	336	4	340
Unmetered Scattered Load			
Connections	481	-5	475
kWh	2,002,380	22,527	2,024,907
Total of Above			
Customer/Connections	63,827	-59	63,767
kWh	945,748,229	10,639,486	956,387,714
kW from applicable classes	1,368,948	15,400	1,384,348

3.3 Is the impact of CDM appropriately reflected in the load forecast?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 3, Tab 2, Schedule 1
Board Staff IR#12c, 13b, 14d, 15, 16, 17 Supplemental IR# 51s, 53s
VECC IR#11, 15

For the purposes of settlement, the Parties agree that the CDM adjustment should be changed from gross to net, and the half year rule being applied to 2011 programs persisting into 2013, a full year of 2012 programs persisting into 2013 along with the half year rule being applied to 2013 programs. The CDM adjustment for the 2013 Test Year load forecast has been allocated to each rate class based on the proportion of the class kWh to the total. The result is a reduction from 967,185,590 kWh to 956,387,714 kWh. Settlement Table #5: CDM Adjusted Forecast, below provides the CDM impact on billed kW and kWh per customer class.

Settlement Table #5: CDM Adjusted Forecast

	Billed Load Forecast before CDM Adjustment (kWh)	Billed Load Forecast after CDM Adjustment (kWh)	CDM Adjustment (kWh)
Residential	343,556,604	339,721,062	3,835,542
General Service < 50 kW	132,887,985	131,404,394	1,483,591
General Service > 50 to 999 kW	291,654,465	288,398,369	3,256,095
General Service > 1000 kW	185,605,020	183,532,884	2,072,136
Streetlights	11,309,881	11,183,615	126,266
Sentinel Lights	123,866	122,483	1,383
Unmetered Scattered Load	2,047,769	2,024,907	22,862
TOTAL	967,185,590	956,387,714	10,797,875

	Billed Load Forecast before CDM Adjustment (kW)	Billed Load Forecast after CDM Adjustment (kW)	CDM Adjustment (kW)
General Service > 50 to 999 kW	792,436	783,589	8,847
General Service > 1000 kW	575,340	568,917	6,423
Streetlights	31,858	31,502	356
Sentinel Lights	344	340	4
TOTAL	1,399,978	1,384,348	15,630

The CDM adjustment of 10,797,875 kWh represents one half of the 2011 programs (i.e. 1/2 of 2,157,479 kWh = 1,078,740 kWh) persisting into 2013, a full year of 2012 programs (i.e. 6,479,424 kWh) persisting into 2013 along with the half year rule being applied to 2013 programs (i.e. 1/2 of 6,479,424 kWh = 3,239,712 kWh).

For the purposes of settlement, the Parties agree the 2013 LRAMVA amount of 15,116,327 kWh and 21,881 kW has been calculated using the OPA's 2011-2014 CDM targets assigned to Thunder Bay, which reflects the actual 2011 CDM results and the persistence of 2011 into 2013. The LRAMVA amount differs from the CDM adjustment of 10,797,875 kWh and 15,630 kW as the full year persistent savings from 2011 must be included in the LRAMVA calculation in order to capture the correct amount of targets assigned to Thunder Bay for 2013. Therefore, the 2013 LRAMVA includes the 2011 persistent savings of 2,157,479 kWh as provided by the OPA's 2011 Final Annual Report, 2012 persistent savings of 6,479,424 kWh and the full year 2013 forecasted savings of 6,479,424 kWh.

Settlement Table #6: LRAMVA Calculation, below provides details of the 2013 kWh and kW savings which will be used in the calculation of the LRAMVA account.

Settlement Table #6: LRAMVA Calculation

	2011	2012	2013	2014	Total
2011 Programs	4.6%	4.6%	4.6%	4.3%	17.9%
2012 Programs		13.7%	13.7%	13.7%	41.0%
2013 Programs			13.7%	13.7%	27.4%
2014 Programs				13.7%	13.7%
	4.6%	18.2%	31.9%	45.3%	100.0%
kWh					
2011 Programs	2,157,479	2,157,479	2,157,479	2,031,020	8,503,456
2012 Programs		6,479,424	6,479,424	6,479,424	19,438,272
2013 Programs			6,479,424	6,479,424	12,958,848
2014 Programs				6,479,424	6,479,424
	2,157,479	8,636,903	15,116,327	21,469,292	47,380,000

The Parties agree, for the purposes of settlement, the LRAMVA amount is to be allocated to the customer classes based on the percentages outlined in proportion of the class kWh to the total. Settlement Table #7: LRAMVA Allocation per Customer Class, below provides details of this allocation.

Settlement Table #7: LRAMVA Allocation per Customer Class

		Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
kWh		5,369,511	2,076,931	4,558,323	2,900,856	176,764	1,936	32,005	15,116,327
kW where applicable				12,385	8,992	498	5		21,881

3.4 Is the proposed forecast of test year throughput revenue appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 3, Tab 3, Schedule 1 VECC IR#17

For the purposes of settlement, the Parties agree on the throughput revenue as set out in Appendix M: Throughput Revenue.

3.5 Is the test year forecast of other revenues appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 3, Tab 3, Schedule 3 Energy Probe IR#11 Energy Probe 26s, 27s VECC IR#18 Supplemental IR#54s, 55s

For the purposes of settlement, the Parties agree upon a forecast of $1,778,000 in Other Distribution Revenue, an increase of $26,264 from $1,751,736 as set out in the Application. Appendix E – 2013 Other Revenue provides additional detail.

The revised other revenue values include the following changes:

- Student funding estimate of $16,500 has been included in Miscellaneous Non-Operating Revenue.
- Amortization of deferred revenue has been increased by $3,986.
- Revenue and Expenses from non-utility operations have been revised to exclude all “non-wires” activity.
- Interest income has been adjusted to remove carrying charges on the regulatory accounts and to reflect the increase such that total Operating Revenues equal the agreed upon amount of $1,778,000.00.

4. OPERATING COSTS

4.1 Is the overall OM&A forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence:
Application: Exhibit 4, Tab 1&2, Schedule 1-4
Board Staff IR# 18, 19, 20, 21, 22, 24, 25, 26 Supplemental IR#55s, 56s
AMPCO IR#9, 10, 11, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29 Supplemental IR#36s, 37s
Energy Probe IR#12, 13 Supplemental IR#28s, 29s
SEC IR#7, 8, 9, 10, 11, 12, 13, 14 Supplemental IR#19s
VECC IR#19, 20, 21, 22, 23, 24, 25 Supplemental IR#55s, 56s

For the purposes of settlement, the Parties agree the 2013 OM&A for the Test Year should be $14,300,000 (MCGAAP), a decrease of $382,415 from the $14,682,415 in the Application Filing. The Parties rely on Thunder Bay's view that it can safely and reliably operate the distribution system based on the total OM&A budget proposed.

Thunder Bay has provided, in Settlement Table #8: OM&A Expense Budget below, a revised OM&A budget based on this proposed total amount. The breakdown of the budget into categories is not intended by the Parties to be in any way a deviation from the normal rule that, once the budget is established, it is up to management to determine through the year how best to spend that budget given the actual circumstances and priorities of the company throughout the test year.

Settlement Table #8: OM&A Expense Budget

	COS Application Filing	Supplemental Interrogatory Adjustments	Supplemental Interrogatory Response	Settlement Adjustments	Settlement Agreement
Operations	$ 3,559,704	$ 25,000	$ 3,584,704		$ 3,584,704
Maintenance	$ 3,978,898	$ (25,372)	$ 3,953,526		$ 3,953,526
Billing & Collecting	$ 2,134,694	$ -	$ 2,134,694		$ 2,134,694
Community Relations	$ 141,862	$ -	$ 141,862		$ 141,862
Administrative and General	$ 4,867,257	$ 5,249	$ 4,872,506		$ 4,872,506
Settlement Agreement Reduction**				$ (387,292)	$ (387,292)
Total	$ 14,682,415	$ 4,877	$ 14,687,292	$ (387,292)	$ 14,300,000

**Thunder Bay Hydro has not yet determined where the reductions will be achieved

4.2 Is the proposed level of depreciation/amortization expense for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 4, Tab 2, Schedule 7
Energy Probe IR#16 Supplemental IR#31s,

For the purposes of settlement, the Parties accept the useful lives and the depreciation expense reported in the continuity schedules in Appendix B.

As cited in the Application, Thunder Bay adopted revised depreciation rates under MCGAAP as detailed in Exhibit 1, Tab 2, Schedule 1 at Page 5. These rates are consistent with the useful lives indicated in the Kinectrics Study dated July 8, 2010 which was commissioned by the OEB as noted at Exhibit 4, Tab 2, Schedule 7. See Settlement Table #9: Depreciation Useful Lives.

Thunder Bay is implementing this depreciation approach effective from January 1, 2013 and has applied it to the Test Year in its evidence.

Settlement Table #9: Depreciation Useful Lives

Settlement Table #9: Depreciation and Useful Lives

OEB	Description	CGAAP Amortization Period	TUL/Useful Life Range per Kinetrics Report	MCGAAP Amortization Period
1805	**Land**	N/A	N/A	N/A
1806	**Land Rights**	N/A	N/A	N/A
1808	**Operations Centre**	50	50-75	50
1808	**Garage**	50	50-75	50
1810	**Leasehold Improvements**	5	5	5
1820	**Distribution Station Equipment -ARO**	30	N/I	Based on estimated date of demolition
1820	**Distribution Station Equipment - Normally Primary below 50 kV**	30	15-50	15-50
1830	**Poles, Towers and Fixtures**	25		
	Wood Poles		40	40
	Steel Cross Arms		70	70
	Fibre Glass Cross Arms		NI	80
1835	**Overhead Conductors and Devices**	25		
	Switches		45	40
	Primary and Neutral Cables		60	60
	Secondary Cables		60	60
1840	**Underground Conduit**	25		
	Trenches		N/I	40
	Conduits		50	80
	Foundations		55	55
1845	**Underground Conductors and Devices**	25		
	Primary Cables in Duct		40	40
	Primary Cables Direct Buried		30	30
	Secondary Cables in Duct		35	40
	Secondary Cables Direct Buried		30	40
	Underground Switchgear			30
1850	**Line Transformers**	25	40	40
1850	**Transformer ARO**	25		
1855	**Services (Underground, Overhead)**	25	40/60	40/60
1860	**Meters**			
	Smart Meters, Repeaters, Data Collectors		10-20	15
	Industrial	25	25-35	35
	Current & Potential Transformer		35-50	50
	Primary Meter		35-50	50
1915	**Office Furniture and Equipment**	10	5-15	10
1920	**Computer Equipment - Hardware**	5	3-5	3/5
1925	**Computer Software**	5	2-5	2
1930	**Transportation Equipment**			
	Trucks & Buckets		5-15	15
	Trailers	5/8	5-20	20
	Vans/Cars		5-10	12
1935	**Stores Equipment**	10	5-10	10
1940	**Tools, Shop and Garage Equipment**	10	5-10	10
1945	**Measurement and Testing Equipment**	10	5-10	10
1950	**Power Operated Equipment**	10	5-10	10
1955	**Communication Equipment**	5	2-10	5
1960	**Miscellaneous Equipment**	10	5-10	10
1980	**System Supervisory Equipment**	30	20	20
2440	**Deferred Revenue**	25	Based on asset	40-80
1995	**Contributions and Grants**	25	Based on asset	40-80
1609	**Hydro One Current & Voltage Transformer Upgrades**	25	15-30	30

N/A Not Applicable
N/I Not Indicated in Kinetrics Study

4.3 Are the 2013 compensation costs and employee levels appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 4, Tab 2, Schedule 4 AMPCO IR#21a-29a, Supplemental IR#37s SEC IR#11-14 VECC IR#24

For the purpose of settlement, the Parties accept that Thunder Bay's forecasted 2013 Test Year compensation costs and employee levels may be affected by the overall reduction in 2013 Test Year OM&A discussed above in Section 4.1.

All Parties accept that the compensation costs and employee levels in the revised OM&A budget are appropriate.

4.4 Is the test year forecast of property taxes appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 4, Tab 2, Schedule 5 Board Staff IR#22, Supplement IR#56s Energy Probe IR#15

Thunder Bay has included property taxes of $155,091 payable in the 2013 Test Year as part of OM&A expenses which have been agreed to by all Parties.

4.5 Is the test year forecast of PILs appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 4, Tab 3, Schedule 1

For the purpose of settlement, the parties accept Thunder Bay's 2013 Test Year PILs forecast of $0 as set out in Appendix F to this Settlement Agreement. Please see Appendix F – 2013 PILs (Updated), for additional details. The changes result from other changes throughout this Agreement.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC,AMPCO
Evidence:	Application: Exhibit 5, Tab 1, Schedule 1,2 Board Staff IR#29-30

Consistent with the terms of its shareholder's directive, Thunder Bay operates under a rate minimization philosophy which permits Thunder Bay to raise capital as necessary to fund its capital needs. Thunder Bay and its shareholder have otherwise minimized cost increases on existing ratepayers by setting the interest rate on the promissory note with the utility at zero, and foregoing dividend payments from the utility. The Intervenors acknowledge the efforts of Thunder Bay to reduce the impact on rates through its implementation of the rate minimization philosophy.

For the purposes of settlement, the Parties agree that Thunder Bay's proposed capital structure of 56% long term debt, 4% short term debt, and 40% equity is appropriate.

This Settlement Agreement has been prepared using Thunder Bay's applied for Return on Equity (7%) and the Board's updated Cost of Capital Parameters short term debt (2.07%) for cost of service applications for rates effective May 1, 2013, issued on February 14, 2013.

For the purposes of settlement, the Parties agree to the adjusted calculation of the long-term debt rate of 1.53% in accordance with Settlement Table #11: Long-Term Debt Rate for 2013 (see issue 5.2 below).

The revised cost of capital parameters are show in Settlement Table #10: Cost of Capital for 2013. Please also refer to Appendix G – 2013 Cost of Capital.

Settlement Table #10: Cost of Capital for 2013

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	52,269,909	56.00%	1.53%	797,185
Unfunded Short Term Debt	3,733,564	4.00%	2.07%	77,285
Total Debt	56,003,473	60.00%		874,470
Common Share Equity	37,335,649	40.00%	7.00%	2,613,495
Total equity	37,335,649	40.00%		2,613,495
Total Rate Base	93,339,122	100.00%	3.74%	3,487,965

5.2 Is the proposed long term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 5, Tab 1, Schedule 1
Board Staff IR#31, Supplemental IR#59s
Energy Probe IR#17, Supplemental IR#33s-a
SEC IR#16-17
VECC IR#27a

For the purposes of settlement, the Parties agree to the adjusted calculation of the long-term debt rate in accordance with Settlement Table #11: Long-Term Debt Rate for 2013. This reflects a pro-rating of debt to be issued in 2013 as well as Thunder Bay's proposal to convert in 2013 a portion equal to $7,000,000 of the long-term debt currently held by the City of Thunder Bay into equity, thereby reducing the value of the City note to $26,490,500. Thunder Bay's shareholder has agreed to such a conversion, the purpose of which is to ensure Thunder Bay maintains an appropriate debt-to-equity split with other third party lenders.

The calculation of the long term debt rate is set out in Appendix G to this Agreement.

Settlement Table #11: Long-Term Debt Rate for 2013

DEBT AND CAPITAL COST STRUCTURE							
Weighted Debt Cost							
Description	Debt Holder	Affliated with LDC?	Date of Issuance	Average Principal	Term (Years)	Rate%	Interest Cost
Promissory Note	The Corporation of the City of Thunder Bay**	Y	September 2011	26,490,500		0.00%	0
2012 Infrastructure Financing	Unknown	N	May 2013	3,866,667	30	4.12%	159,307
2013 Infrastructure Financing	Unknown	N	September 2013	2,050,000	30	4.12%	84,460
Smart Meter Financing in Rate Base	TD Commercial Bank	N	Jan. 1, 2012	6,688,761	15	5.27%	352,498
			2013 Total Long Term Debt	39,095,928	Total Interest Cost for 2013		596,264
**The Promissory Note for the City of Thunder Bay will be updated to reflect conversion of $7,000,000 of the debt to equity.					Weighted Debt Cost Rate for 2013		1.53%

6. STRANDED METERS

6.1 Is the proposal related to Stranded Meters appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 9, Tab 3, Schedule 1 VECC IR#46

For the purposes of settlement, the Parties accept Thunder Bay's proposal related to stranded meters at Exhibit 9, Tab 3, Schedule 1 of the Application.

In summary, Thunder Bay Hydro proposes to dispose of the stranded meter costs based on the principles of cost causality and practicality and recovered through a rate rider for the applicable customer classes over a 12 month period starting May 1, 2013 and using the 2013 forecasted number of customers to calculate the Stranded Asset Rate Rider ("SMRR") by rate class. Below is Table 9-3.2 (from the original application) summarizing the SMRR, updated to actual 2012 balance and to reflect the revised customer forecast numbers arising from this Settlement.

Table 9-3.2 REVISED – Rate Rider Calculation

Stranded Meter Costs				
Net Book Value as at Dec. 31/12	$1,568,091			A
	Residential	**GS < 50 kW**	**Total**	
Number of Customers - 2013 Forecast	44,881	4,492	49,373	B
Porportion of Stranded NBV $	78%	22%	100%	C
Allocation of NBV to rate classes	$1,229,064	$339,028	$1,568,091	D = A * C
Proposed Disposition Period	12 months			E
SMRR per month	**$2.28**	**$6.29**		F = D / B / 12

7. COST ALLOCATION

7.1 Is Thunder Bay's cost allocation appropriate

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 7, Tab 1, Schedule 1
AMPCO IR#30a & 32a
VECC IR#28, Supplemental 57s

For the purposes of settlement, the Parties have agreed that Thunder Bay's cost allocation methodology is appropriate and the revenue-to-cost ratios for the 2013 Test Year, reflecting the agreed-upon 2013 Test Year Revenue Requirement, will be as set out in Settlement Table #12: 2013 Test Year Revenue to Cost Ratios, below.

Settlement Table #12: 2013 Test Year Revenue to Cost Ratios

Class	Revenue Requirement - 2013 Cost Allocation Model - Line 40 from O1 in CA	2013 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2013 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2013 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio
Residential	12,046,608	10,942,756	1,129,610	12,072,366	100.2%	100.2%	100.2%
GS < 50 kW	3,302,193	3,159,862	255,797	3,415,659	103.4%	103.4%	103.4%
GS >50 to 999 kW	3,846,055	2,588,386	266,564	2,854,950	74.2%	74.2%	87.1%
GS >1000 to 4999 kW	1,378,292	1,639,977	90,251	1,730,228	125.5%	125.5%	120.0%
Sentinel Lights	16,421	15,288	1,961	17,248	105.0%	105.0%	105.0%
Street Lighting	346,396	784,119	29,114	813,233	234.8%	234.8%	120.0%
Unmetered and Scattered	52,647	80,224	4,703	84,928	161.3%	161.3%	120.0%
TOTAL	**20,988,612**	**19,210,613**	**1,778,000**	**20,988,613**			

7.2 Are the proposed revenue-to-cost ratios for each class appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 7, Tab 1, Schedule 2 Board Staff IR#33a-33b, 34a AMPCO IR#31a, 33a-33g, Supplemental IR#38s

For the purposes of settlement, the Parties accept the revenue-to-cost ratios for the 2013 Test Year, as set out under issue 7.1, above, and that no further adjustments will be required from 2014-2016 as part of this Agreement. The Parties acknowledge that Thunder Bay's revenue to cost ratios remain subject to further Board policy changes of general application over this period.

8. RATE DESIGN

8.1 Are the fixed-variable splits for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 8, Tab 1, Schedule 1
Board Staff IR#37a
AMPCO IR#34a
VECC IR#31a-31b, #32a-32b, Supplemental IR#58s-a

For the purposes of settlement, the Parties agree to the fixed and variable rates as set out in Settlement Table #14: 2013 Base Revenue Distribution Rates, below. The derivation of these fixed and variable rates is set out below in detail in Settlement Table #13: Fixed Charge Analysis and the explanatory note below.

Settlement Table #13: Fixed Charge Analysis

Fixed Charge Analysis							
Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2012 Rates From OEB Approved Tariff Plus SMIRR	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)	Proposed Fixed Charges at Settlement
Residential	44.26%	55.74%	100.00%	11.33	11.72	13.19	13.53
GS < 50 kW	63.98%	36.02%	100.00%	21.11	24.68	26.29	27.25
GS >50 to 999 kW	39.99%	60.01%	100.00%	299.57	241.78	113.94	311.68
GS >1000 to 4999 kW	59.60%	40.40%	100.00%	2,770.91	2,794.55	526.11	2,848.01
Sentinel Lights	11.88%	88.12%	100.00%	6.66	6.40	7.80	6.89
Street Lighting	54.57%	45.43%	100.00%	1.11	2.16	6.29	1.15
Unmetered and Scattered	34.12%	65.88%	100.00%	6.75	8.91	5.70	6.96

For the purposes of settlement, the Parties agree to the adjusted monthly fixed charges for each class as defined below and is based on the information provided in Settlement Table #13: Fixed Charge Analysis.

- For Residential the monthly fixed charge will be $12.63 which is the halfway point of the approved 2012 monthly fixed charge including SMIRR of $11.72 and the proposed 2013 monthly fixed charge of $13.53.

- For GS < 50 kW the monthly fixed charge will be $25.96 which is the halfway point of the approved 2012 monthly fixed charge included SMIRR of $24.68 and the proposed 2013 monthly fixed charge of $27.25.

- For GS > 50 to 999 kW the monthly fixed charge will be $195.33 which is the halfway point of $276.73 and Minimum System with PLCC Adjustment (i.e. Ceiling from Cost Allocation model) value of $113.94. The $276.73 represents the halfway point of the approved 2012 monthly fixed charge of $241.78 and the proposed 2013 monthly fixed charge of $311.68.

- For GS > 1000 to 4999 kW the monthly fixed charge is set at the approved 2012 monthly fixed charge.

- For Sentinel Lighting, Street Lighting and Unmetered Scattered Load the current fixed/variable is used to define the fixed portion of the revenue assigned to the class and the resulting monthly fixed charge.

Settlement Table #14: 2013 Base Revenue Distribution Rates

Customer Class	Connection	Customer	kW	kWh
Residential	0.00	12.63		0.0122
GS < 50 kW	0.00	25.96		0.0134
GS >50 to 999 kW	0.00	195.33	2.4857	
GS >1000 to 4999 kW	0.00	2,794.55	2.2079	
Sentinel Lights	6.66		5.3399	
Street Lighting	1.11		6.6959	
Unmetered and Scattered	6.75			0.0099

8.2 Are the proposed retail transmission service rates ("RTSR") appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 8, Tab 1, Schedule 2
Board Staff IR#39

For the purposes of settlement the Parties agree the Retail Transmission Service Rates ("RTSRs"), based on the updated Uniform Transmission Rates issued by the Board on December 20, 2012 in EB-2012-0031, are appropriate, and are as set out in Settlement Table #15: RTSR Network and RTSR Connection Rates, below.

Settlement Table #15: RTSR Network and RTSR Connection Rates

Settlement Table #15: RTSR Network and RTSR Connection Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	0.0065	0.0047
General Service Less Than 50 kW	kWh	0.0062	0.0044
General Service 50 to 999 kW	kW	2.4536	1.6885
General Service 50 to 999 kW - Interval Metered	kW	2.6027	1.8662
General Service 1,000 to 4,999 kW	kW	2.6027	1.8662
Unmetered Scattered Load	kWh	0.0062	0.0044
Sentinel Lighting	kW	1.8599	1.3327
Street Lighting	kW	1.8503	1.3053

8.3 Are the proposed loss factors appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 8, Tab 1, Schedule 3

For the purposes of settlement, the Parties accept the proposed loss factors set out in Thunder Bay's Application at Exhibit 8, Tab 1, Schedule 3 as appropriate.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 9, Tab 1 & 2, Schedule 1 & 2 Board Staff IR#44a-44e, Supplemental IR#60s-a-60s-d VECC IR#33a-33c

For the purposes of settlement, the Parties agree the account balances, cost allocation methodology and disposition period for the deferral and variance accounts as presented in the Evidence cited above, adjusted for the matters discussed below, are appropriate.

- For the purposes of settlement, the Parties agree to adjust the LRAM (1568) account to reflect the removal of the persistence of 2011 CDM programs in 2012 on the basis that final OPA results are not yet available for 2012. The Parties agree that Thunder Bay will be entitled to recover these LRAM amounts at the next rate filing once final OPA results are available for the 2012 year.

Settlement Table #16: Deferral and Variance Accounts, below summarizes the Parties' agreement with respect to the disposal of the balances of the accounts, including the updates that have occurred to the deferral and variance accounts for which disposal is sought in 2013:

Settlement Table #16: Deferral and Variance Accounts

Group 1 Deferral / Variance Accounts – Excluding 1588 GA sub-account

Group 1 Deferral / Variance Accounts		Total
1580	RSVA - Wholesale Market Service Charge	($1,470,667)
1584	RSVA - Retail Transmission Network Charge	($244,701)
1586	RSVA - Retail Transmission Connection Charge	($436,592)
1588	RSVA - Power (excluding Global Adjustment)	($1,203,459)
1590	Recovery of Regulatory Asset Balances	$11
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	($38,086)
1595	Disposition and Recovery/Refund of Regulatory Balances (2009)	($118,956)
Total		($3,512,450)

Group 2 Deferral / Variance Accounts

Group 2 Deferral / Variance Accounts		Total
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$121

1508	Other Regulatory Assets - Sub-Account - Pension Contributions	$474
1518	Retail Cost Variance Account - Retail	$148,737
1525	Misc. Deferred Debits	$1
1548	Retail Cost Variance Account - STR	$137,892
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	($92,434)
Total		$194,791

1588 GA Sub-Account

		Total
1588	RSVA - Power - Sub-account - Global Adjustment	$1,022,422

1568 LRAM Variance Account

		Total
1568	LRAM Variance Account	$20,418

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Thunder Bay, Energy Probe, SEC, VECC, AMPCO
Evidence:	Application: Exhibit 9, Tab 2, Schedule 3 Board Staff IR#43a-43b

For the purposes of settlement, the Parties accept the proposed rate riders to dispose of those account balances that are the subject of disposition at this time on a final basis. The Parties have agreed to a disposition period of 12 months. Settlement Table #17: Deferral and Variance Account Disposition Balances below reflects the balances of the accounts being disposed.

Settlement Table #17: Deferral and Variance Account Disposition Balances

	COS Application Filing	First Round Interrogatory Adjustments	First Round Interrogatory Response	Supplemental Interrogatory Adjustments	Supplemental Interrogatory Response	Settlement Adjustments	Settlement Agreement
DVA Allocated Account Balances							
Residential	(1,006,759)	62,697	(944,062)	(30,131)	(974,193)	(13,437)	(987,630)
General Service Less Than 50 kW	(474,072)	12,315	(461,757)	(8,345)	(470,102)	(6,282)	(476,384)
General Service 50 to 999 kW	(1,081,340)	6,695	(1,074,645)	(7,306)	(1,081,951)	(140)	(1,082,091)
General Service 1,000 to 4,999 kW	(685,888)	(11,876)	(697,764)	(3,902)	(701,666)	(37)	(701,703)
Unmetered Scattered Load	(4,889)	(1,814)	(6,703)	(377)	(7,080)	(0)	(7,080)
Sentinel Lighting	326	94	420	(40)	380	(0)	380
Street Lighting	27,568	(68,112)	(40,544)	(2,189)	(42,733)	0	(42,733)
	(3,225,054)	(1)	(3,225,055)	(52,290)	(3,277,345)	(19,896)	(3,297,241)
			Note 1		Note 2		
Global Adjustment - Non-RPP Customers							
Residential	67,882	0	67,882	0	67,882	0	67,882
General Service Less Than 50 kW	40,981	0	40,981	0	40,981	0	40,981
General Service 50 to 999 kW	508,342	0	508,342	0	508,342	0	508,342
General Service 1,000 to 4,999 kW	380,914	0	380,914	0	380,914	0	380,914
Unmetered Scattered Load	784	0	784	0	784	0	784
Sentinel Lighting	0	0	0	0	0	0	0
Street Lighting	23,518	0	23,518	0	23,518	0	23,518
	1,022,421	0	1,022,421	0	1,022,421	0	1,022,421

Note 1 - Corrections made in 9-Staff-41 to 43 for customer count and recovery share percentages
Note 2 - The net refund changed due to the decision to defer IFRS costs of $52,290
Note 3- The 2011 LRAM persistence in 2012 has been removed ($19,896).

Settlement Table #18: Deferral and Variance Account Disposition Rate Riders below reflects the rate riders for disposition over a period of 12 months, as was submitted in its second round of interrogatories dated March 25, 2013 in the EDDVAR file and updated to remove the 2011 programs persisting into 2012 for LRAM as per the Settlement Agreement.

Settlement Table #18: Deferral and Variance Account Disposition Rate Riders

2013 Deferral and Variance Account Rate Rider by Class

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	337,828,768	(987,630)	**(0.0029)**	$/kWh
General Service Less Than 50 kW	kWh	135,513,010	(476,384)	**(0.0035)**	$/kWh
General Service 50 to 999 kW	kW	741,149	(1,082,091)	**(1.4600)**	$/kW
General Service 1,000 to 4,999 kW	kW	518,430	(701,703)	**(1.3535)**	$/kW
Unmetered Scattered Load	kWh	1,965,510	(7,080)	**(0.0036)**	$/kWh
Sentinel Lighting	kW	337	380	**1.1274**	$/kW
Street Lighting	kW	31,834	(42,733)	**(1.3424)**	$/kW
Total			**(3,297,241)**		

Rate Rider Calculation for RSVA - Power - Sub-account - Global Adjustment

2013 Non-RPP Global Adjustment Rate Rider by Class

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -	
Residential	kWh	33,772,368	67,882	**0.0020**	$/kWh
General Service Less Than 50 kW	kWh	20,388,898	40,981	**0.0020**	$/kWh
General Service 50 to 999 kW	kW	651,576	508,342	**0.7802**	$/kW
General Service 1,000 to 4,999 kW	kW	539,790	380,914	**0.7057**	$/kW
Unmetered Scattered Load	kWh	389,969	784	**0.0020**	$/kWh
Sentinel Lighting	kW	-	-	**-**	$/kW
Street Lighting	kW	33,125	23,518	**0.7100**	$/kW
Total			**1,022,422**		

10. GREEN ENERGY ACT PLAN

10.1 Is Thunder Bay's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

Status: **Complete Settlement**

Supporting Parties: Thunder Bay, Energy Probe, SEC, VECC, AMPCO

Evidence: Application: Exhibit 9, Tab 4, Schedule 1

For the purposes of settlement, the Parties accept Thunder Bay's Green Energy Plan as set out in the Application, subject to the following adjustments that were made during the interrogatory process:

Below please find a summary of Thunder Bay's proposal for funding its GEA Capital Expenditures for 2013:

GEA Capital Expenditure Forecast for 2013 (MCGAAP)

	Application	Feb. 20/13	Mar. 25/13	Settlement
Funded by TBH Rate Base	210,440	210,440	77,643	77,643
External Funding	353,239	353,239	353,239	353,239
Total	563,679	563,679	430,882	430,882
Reference	E2-T3-S2 pg. 17	2-Staff-9	2-Staff-48s	

Please note as discussed in 2-Staff-48s, the reduction in capital expenditures funded by Thunder Bay's rate base is due to the recent change in its GEA Plan in which the number of RESOP reclosers required dropped from 3 to 1.

For clarification, the amount of capital expenditures included in Thunder Bay's rate base for 2013 is $77,643 and the amount to be funded by the IESO is $353,239 which will be included in Account 1531. The Parties anticipate that the Board will facilitate the compensation payments from the IESO to Thunder Bay as per O.Reg. 330/09.

Appendix A – Summary of Significant Changes

In response 1-VECC-47s, Thunder Bay provided a summary showing the proposed adjustments arising from the first and supplementary interrogatories. Using the same table format as was proposed by VECC in that supplemental interrogatory, and starting with those adjusted values in the row titled "Supplemental Submission", the table below provides a summary of the significant changes arising under this Proposed Settlement Agreement.

Reference	Item	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILS	OM&A	Service Revenue Requirement	Revenue Offsets	Base Revenue Requirement	Gross Revenue Deficiency
	Supplemental Submission	3,631,812	3.89%	93,304,978	109,417,716	14,224,303	3,201,779	0	14,687,292	21,520,883	1,772,099	19,748,785	1,407,064
	LTD/STD Rate Change	3,486,689	3.74%	93,304,978	109,417,716	14,224,303	3,201,779	0	14,687,292	21,375,761	1,772,099	19,603,662	1,261,941
	Change	(145,123)	-0.16%	0	0	0	0	0	0	(145,123)	0	(145,123)	(145,123)
	OM&A Reduction	3,484,808	3.74%	93,254,630	109,030,424	14,173,955	3,201,779	0	14,300,000	20,986,587	1,772,099	19,214,489	872,768
	Change	(1,881)	0.00%	(50,348)	(387,292)	(50,348)	0	0	(387,292)	(389,173)	0	(389,173)	(389,173)
	Other Revenue Increase	3,484,808	3.74%	93,254,630	109,030,424	14,173,955	3,201,779	0	14,300,000	20,986,587	1,778,000	19,208,588	866,866
	Change	0	0.00%	0	0	0	0	0	0	0	5,901	(5,901)	(5,902)
	Cost of Power Update	3,489,999	3.74%	93,393,556	110,099,088	14,312,881	3,201,779	0	14,300,000	20,991,779	1,778,000	19,213,779	872,058
	Change	5,191	0.00%	138,926	1,068,664	138,926	0	0	0	5,191	0	5,191	5,192
	Depreciation Reduction	3,490,020	3.74%	93,394,122	110,099,088	14,312,881	3,200,647	0	14,300,000	20,990,668	1,778,000	19,212,668	870,926
	Change	21	0.00%	566	0	0	(1,132)	0	0	(1,111)	0	(1,111)	(1,132)
	Capital Reduction	3,487,965	3.74%	93,339,122	110,099,088	14,312,881	3,200,647	0	14,300,000	20,988,613	1,778,000	19,210,613	868,892
	Change	(2,055)	0.00%	(55,000)	0	0	0	0	0	(2,055)	0	(2,055)	(2,034)
	Load Forecast Adjustments	3,487,965	3.74%	93,339,122	110,099,088	14,312,881	3,200,647	0	14,300,000	20,988,613	1,778,000	19,210,613	737,237
	Change	0	0.00%	0	0	0	0	0	0	0	0	0	(131,655)

Total Change (669,827)

Appendix B – Continuity Table (Updated)

Year 2013MCGAAP

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	1,175,257	77,200	-	1,252,457	(958,380)	(51,926)	-	(1,010,306)	242,151
CEC	1612	Land Rights (Formally known as Account 1906)				-				-	-
N/A	1805	Land	133,038			133,038	-			-	133,038
47	1808	Buildings	3,932,848	3,500	(123,959)	3,812,389	(1,862,466)	(72,044)	58,640	(1,875,870)	1,936,518
47	1808	Garage		3,300,000		3,300,000	-	(25,250)		(25,250)	3,274,750
13	1810	Leasehold Improvements	63,262			63,262	(5,218)	(8,399)		(13,617)	49,645
47	1820	Distribution Equipment - ARO	-	45,125		45,125		(7,386)		(7,386)	37,738
47	1820	Distribution Equpment Normally Primary below 50 kV	8,124,042	776		8,124,818	(5,873,488)	(319,827)		(6,193,315)	1,931,503
47	1825	Storage Battery Equipment				-				-	-
47	1830	Poles, Towers & Fixtures	32,612,443	3,411,550	(216,435)	35,807,558	(11,375,483)	(718,067)	213,933	(11,879,617)	23,927,941
		Steel Cross Arms	114,893	9,541	(1,274)	123,160	(19,030)	(1,601)	422	(20,210)	102,950
		fibre Glass Cross Arms	10,810	1,274		12,084	(1,274)	(138)		(1,412)	10,672
47	1835	O/H Conductors & Devices - Switches	2,604,170	210,276	(27,097)	2,787,350	(1,574,157)	(57,326)	26,024	(1,605,459)	1,181,891
		O/H Conductors & Devices - Primary & Neutral Cables	26,122,867	1,970,919	(328,450)	27,765,335	(12,741,860)	(326,782)	305,947	(12,762,696)	15,002,640
		O/H Conductors & Devices - Secondary Cables	3,528,724	569,243		4,097,967	(1,348,473)	(50,952)		(1,399,425)	2,698,542
		O/H Conductors & Devices - Reclosures	880,852	541,664		1,422,516	(245,126)	(22,587)		(267,712)	1,154,804
47	1840	U/G Conduit - Trenches	1,384,431	-		1,384,431	(1,246,119)	(14,463)		(1,260,582)	123,849
		U/G Conduit - Conduits	11,187,379	331,344		11,518,723	(6,521,167)	(74,246)		(6,595,412)	4,923,311
		U/G Conduit - Foundations	1,204,383	211,852		1,416,235	(290,603)	(20,164)		(310,767)	1,105,468
47	1845	U/G Conductors & Devices - Primary Cables in Duct	11,137,128	532,482		11,669,610	(3,351,962)	(243,833)		(3,595,795)	8,073,815
		U/G Conductors & Devices - Primary Cables Direct Buried	4,878,456			4,878,456	(4,361,795)	(58,711)		(4,420,507)	457,949
		U/G Conductors & Devices - Secondary Cables in Duct	1,076,901			1,076,901	(508,962)	(19,441)		(528,403)	548,498
		U/G Conductors & Devices - Secondary Cables Direct Buried	1,161,140			1,161,140	(1,067,314)	(7,215)		(1,074,529)	86,610
		U/G Conductors & Devices - UG Switchgear	688,012	50,000		738,012	(191,937)	(20,772)		(212,709)	525,303
47	1850	Line Transformers - Vault Combined	914,194	-	(17,024)	897,170	(850,678)	(11,082)	16,128	(845,632)	51,538
		Line Transformers - Enclosure Combined	397,326		(21,896)	375,430	(338,715)	(5,522)	20,745	(323,492)	51,938
		Line Transformers - Pole Top Combined	15,369,516	1,239,335	(243,541)	16,365,310	(8,091,333)	(314,814)	167,194	(8,238,953)	8,126,356
		Line Transformers - Pad MountTransformer Single Phase	5,530,618		(5,460)	5,525,158	(3,208,301)	(105,096)	5,179	(3,308,219)	2,216,939
		Line Transformers - Pad Mount Transformer 3 Phase	5,244,150		(85,722)	5,158,427	(3,021,786)	(94,510)	54,556	(3,061,739)	2,096,688
47	2320	ARO	299,629			299,629	(79,665)	(9,752)		(89,417)	210,212
47	1855	Services (O/H & U/G) - O/H Conductors	8,759,986	584,059	(112,593)	9,231,452	(4,844,203)	(100,596)	139,045	(4,805,754)	4,425,698
		Services (O/H & U/G) - U/G in Duct	7,507,523	293,624	(31,895)	7,769,252	(5,036,417)	(103,717)		(5,140,135)	2,629,117
		Services (O/H & U/G) -U/G Direct Buried	4,714,182			4,714,182	(4,436,160)	(34,772)		(4,470,932)	243,250
47	1860	Meters - Industrial/Commercial Energy Meters	98,013	-		98,013	(68,516)	(2,254)		(70,770)	27,243
		Meters - CT & PT	367,615			367,615	(260,486)	(4,314)		(264,800)	102,815
		Meters - Primary	716,681	28,229		744,910	(509,240)	(8,369)		(517,609)	227,301
										-	-
47	1860	Meters (Smart Meters) - Phase 1	5,667,456	118,374		5,785,830	(1,344,320)	(380,533)		(1,724,853)	4,060,977
		Meters (Smart Meters) - Phase 2	560,165			560,165	(136,029)	(37,319)		(173,349)	386,817
		Meters (Smart Meters) - Phase 3	1,227,479			1,227,479	(249,823)	(81,630)		(331,453)	896,026
		Meters (Smart Meters) - Repeaters Data Coll	402,195			402,195	(90,124)	(26,756)		(116,879)	285,316
N/A	1905	Land				-				-	-
47	1908	Buildings & Fixtures				-				-	-
13	1910	Leasehold Improvements				-				-	-
8	1915	Office Furniture & Equipment (10 years)	1,420,041	36,050		1,456,091	(1,168,737)	(42,182)		(1,210,919)	245,172
8	1915	Office Furniture & Equipment (5 years)	-	-		-	-	-		-	-
10	1920	Computer Equipment - Hardware	3,015,735	81,600	(44,200)	3,053,135	(2,705,432)	(182,002)	37,880	(2,849,554)	203,581
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				-				-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			-				-	-
10	1930	Transportation Equipment - Trailers	473,519	-	-	473,519	(473,519)	0	-	(473,519)	(0)
10	1930	Transportation Equipment - Buckets and Heavy Equipment	4,833,179	595,345	(181,812)	5,246,712	(3,229,801)	(184,208)	181,812	(3,232,197)	2,014,515
10	1930	Transportation Equipment - Light Vehicles	1,233,315	135,000	(181,698)	1,186,617	(851,488)	(37,358)	181,698	(707,147)	479,470
8	1935	Stores Equipment	63,417			63,417	(62,835)	-		(62,835)	582
8	1940	Tools, Shop & Garage Equipment	2,490,345	73,700		2,564,045	(2,263,684)	(69,194)		(2,332,877)	231,168
8	1945	Measurement & Testing Equipment	291,550	22,940		314,490	(159,853)	(25,371)		(185,224)	129,267
8	1950	Power Operated Equipment	204,487	13,400		217,887	(59,790)	(20,758)		(80,548)	137,339
8	1955	Communications Equipment	237,543	104,756		342,299	(164,718)	(9,446)		(174,164)	168,135
8	1955	Communication Equipment (Smart Meters)				-				-	-
8	1960	Miscellaneous Equipment				-				-	-
47	1975	Load Management Controls Utility Premises				-				-	-
47	1980	System Supervisor Equipment	515,152	-		515,152	(378,896)	(34,343)		(413,239)	101,913
47	1985	Miscellaneous Fixed Assets				-				-	-
	2440	Deferred Revenue		(1,308,894)		(1,308,894)		16,698		16,698	(1,292,196)
47	1995	Contributions & Grants	(17,276,089)	-		(17,276,089)	3,726,998	456,959		4,183,957	(13,092,132)
47	1996	Hydro One Current & Voltage Transformer	1,272,321	-		1,272,321	(137,026)	(42,411)		(179,437)	1,092,884
WIP		Work in Process	3,204,185	(1,921,233)		1,282,952	-	-		-	1,282,952
		Total	**171,776,463**	**11,363,031**	**(1,623,058)**	**181,516,435**	**(94,039,392)**	**(3,615,784)**	**1,409,204**	**(96,245,972)**	**85,270,463**

Amortization allocation to other t/b accounts and o/h	431,835
Hydro One Current & Voltage Transformer posted to separate account	42,411
Govt assistance directly credited to income 4245	(16,698)
	(3,158,235)

The following table provides a reconciliation of the above continuity table and the Average Net Fixed Assets as shown at Row C in the Settlement Agreement Column of Table #2: Rate Base. The following provides detail as to the amounts that have been removed for the Asset Retirement Obligations (AROs) and the Work in Progress (WIP).

Year	Cost	Accumulated Depreciation	Net Book Value	WIP	ARO	NBV for Rate Base
2012	$ 171,776,463	$ 94,039,392	$ 77,737,071	$ (3,204,185)	$ (219,964)	$ 74,312,922
2013	$ 181,516,435	$ 96,245,972	$ 85,270,463	$ (1,282,952)	$ (247,951)	$ 83,739,560
Average Net Fixed Assets -C- Settlement Agreement Column in Table 2 Rate Base						$ 79,026,241

Appendix C – Cost of Power Calculation (Updated)

REVISED: Table 2-4.2 - Cost of Power

2013 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	339,721,062		90%
General Service < 50 kW	131,404,394		86%
General Service 50 to 999 kW	288,398,369	783,589	16%
General Service > 1,000 kW	183,532,884	568,917	1%
Street Lighting	11,183,615	31,502	0%
Sentinel Lighting	122,483	340	100%
Unmetered Scattered Load	2,024,907		81%
TOTAL	**956,387,714**	**1,384,348**	
	0	0	

Electricity - Commodity RPP	**2013**	**2013 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	307,194,322	1.0389	319,133,922	$0.07932	$25,313,703
General Service < 50 kW	112,511,645	1.0389	116,884,590	$0.07932	$9,271,286
General Service 50 to 999 kW	46,301,202	1.0389	48,100,772	$0.07932	$3,815,353
General Service > 1,000 kW	1,796,542	1.0389	1,866,368	$0.07932	$148,040
Street Lighting	0	1.0389	0	$0.07932	$0
Sentinel Lighting	122,483	1.0389	127,243	$0.07932	$10,093
Unmetered Scattered Load	1,639,631	1.0389	1,703,358	$0.07932	$135,110
TOTAL	**469,565,825**		**487,816,254**		**$38,693,585**

Electricity - Commodity Non-RPP	**2013**	**2013 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	32,526,740	1.0389	33,790,944	$0.08001	$2,703,613
General Service < 50 kW	18,892,749	1.0389	19,627,046	$0.08001	$1,570,360
General Service 50 to 999 kW	242,097,167	1.0389	251,506,662	$0.08001	$20,123,048
General Service > 1,000 kW	181,736,342	1.0389	188,799,817	$0.08001	$15,105,873
Street Lighting	11,183,615	1.0389	11,618,284	$0.08001	$929,579
Sentinel Lighting	0	1.0389	0	$0.08001	$0
Unmetered Scattered Load	385,276	1.0389	400,250	$0.08001	$32,024
TOTAL	**486,821,889**		**505,743,003**		**$40,464,498**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	352,924,866	$0.0065	$2,294,012
General Service < 50 kW		kWh	136,511,637	$0.0062	$846,372
General Service 50 to 999 kW non interval		kW	691,991	$2.4536	$1,697,869
General Service 50 to 999 kW interval		kW	91,598	$2.6027	$238,402
General Service > 1,000 kW		kW	568,917	$2.6027	$1,480,720
Street Lighting		kW	31,502	$1.8503	$58,288
Sentinel Lighting		kW	340	$1.8599	$633
Unmetered Scattered Load		kWh	2,103,608	$0.0062	$13,042
TOTAL					**$6,629,338**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	352,924,866	$0.0047	$1,658,747
General Service < 50 kW		kWh	136,511,637	$0.0044	$600,651
General Service 50 to 999 kW non interval		kW	691,991	$1.6885	$1,168,427
General Service 50 to 999 kW interval		kW	91,598	$1.8662	$170,940
General Service > 1,000 kW		kW	568,917	$1.8662	$1,061,712
Street Lighting		kW	31,502	$1.3053	$41,120
Sentinel Lighting		kW	340	$1.3327	$453
Unmetered Scattered Load		kWh	2,103,608	$0.0044	$9,256
TOTAL					**$4,711,306**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential		kWh	352,924,866	$0.0044	$1,552,869
General Service < 50 kW		kWh	136,511,637	$0.0044	$600,651
General Service 50 to 999 kW		kWh	299,607,435	$0.0044	$1,318,273
General Service > 1,000 kW		kWh	190,666,185	$0.0044	$838,931
Street Lighting		kWh	11,618,284	$0.0044	$51,120
Sentinel Lighting		kWh	127,243	$0.0044	$560
Unmetered Scattered Load		kWh	2,103,608	$0.0044	$9,256
TOTAL			**993,559,258**		**$4,371,661**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential		kWh	352,924,866	$0.0012	$423,510
General Service < 50 kW		kWh	136,511,637	$0.0012	$163,814
General Service 50 to 999 kW		kWh	299,607,435	$0.0012	$359,529
General Service > 1,000 kW		kWh	190,666,185	$0.0012	$228,799
Street Lighting		kWh	11,618,284	$0.0012	$13,942
Sentinel Lighting		kWh	127,243	$0.0012	$153
Unmetered Scattered Load		kWh	2,103,608	$0.0012	$2,524
TOTAL			**993,559,258**		**$1,192,271**

	2013
4705-Power Purchased	$79,158,083
4708-Charges-WMS	$4,371,661
4714-Charges-NW	$6,629,338
4716-Charges-CN	$4,711,306
4730-Rural Rate Assistance	$1,192,271
Rounding Adjustment	($2)
TOTAL	**96,062,657**

Appendix D – 2013 Customer Load Forecast (Updated)

Forecast Data For 2013 Test Year Projection		
Sum of Quantity		
Class	**Unit of Measure**	**2013 Test Year Normalized**
Residential	**Connection**	44,881
		339,721,062
GS < 50 kW	**# of Customers**	4,492
	kWh	131,404,394
GS >50 to 999 kW	**# of Customers**	515
	kW	783,589
	kWh	288,398,369
GS >1000 to 4999 kW	**# of Customers**	19
	kW	568,917
	kWh	183,532,884
Sentinel Lights	**# of Connections**	169
	kW	340
	kWh	122,483
Street Lighting	**# of Connections**	13,217
	kW	31,502
	kWh	11,183,615
Unmetered and Scattered	**# of Connections**	475
	kWh	2,024,907
Total Check	**# of Cust/Con**	63,767
	kW	1,384,348
	kWh	956,387,714

Appendix E – 2013 Other Revenue (Updated)

Table 3-3.1-Summary of Other Operating Revenue

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Test (CGAAP)	2013 Test (MCGAAP)
Other Operating Revenues							
Specific Service Charges	$ 308,700	$ 320,631	$ 322,428	$ 270,471	$ 303,162	$ 267,807	$ 267,807
Late Payment Charges	$ 282,000	$ 289,447	$ 261,868	$ 297,478	$ 285,249	$ 297,000	$ 297,000
SSS Revenue	$ 131,500	$ 128,694	$ 127,920	$ 131,704	$ 141,004	$ 131,340	$ 131,340
RS Rev	$ 71,800	$ 75,266	$ 66,688	$ 55,954	$ 40,681	$ 59,150	$ 59,150
Serv Tx Requests	$ 3,400	$ 1,681	$ 5,629	$ 1,786	$ 1,605	$ 1,900	$ 1,900
Electric Services Incidental to Energy Sales	$ -	$ -	$ -	$ -		$ -	$ -
Interdepartmental Rents		$ -	$ -	$ -		$ -	$ -
Rent from Electric Property	$ 436,300	$ 460,835	$ 462,179	$ 477,108	$ 481,153	$ 471,000	$ 471,000
Other Utility Operating Income		$ -	$ -	$ -	$ -	$ -	$ -
Other Electric Revenues	$ 2,710	$ 93,337	$ 139,302	$ 202,431	$ 143,980	$ 180,818	$ 180,818
Provision for Rate Refunds		$ (361,129)	$ -	$ -	$ -	$ -	$ -
Government Assistance Directly Credited to Income		$ -	$ -	$ -	$ -	$ -	$ 16,698
Regulatory Debits		$ -	$ -	$ -		$ -	$ -
Regulatory Credits		$ -	$ -	$ -		$ -	$ -
Revenues from Electric Plant Leased to Others		$ -	$ -	$ -		$ -	$ -
SPC Recovery		$ -	$ 224,891	$ 164,329	$ 7,181	$ -	$ -
Revenues from Merchandise, Jobbing, Etc.		$ -	$ -	$ -		$ -	$ -
Costs and Expenses of Merchandising, Jobbing, Etc		$ -	$ -	$ -		$ -	$ -
Profits and Losses from Financial Instrument Hedges		$ -	$ -	$ -		$ -	$ -
Profits and Losses from Financial Instrument Investments		$ -	$ -	$ -		$ -	$ -
Gains from Disposition of Future Use Utility Plant		$ -	$ -	$ -		$ -	$ -
Losses from Disposition of Future Use Utility Plant		$ -	$ -	$ -		$ -	$ -
Gain on Disposition of Utility and Other Property		$ 14,336	$ 400	$ 26,513	$ (7,939)	$ 49,850	$ (14,120)
Loss on Disposition of Utility and Other Property		$ -	$ -	$ -		$ -	$ -
Loss from Retirement of Utility and Other Property		$ -	$ -	$ -		$ (30,000)	$ (30,000)
Gains from Disposition of Allowances for Emission		$ -	$ -	$ -		$ -	$ -
Losses from Disposition of Allowances for Emission	$ 25,000	$ -	$ -	$ -		$ -	$ -
Revenues from Non-Utility Operations	$ (18,114)	$ 83,489	$ 57,979	$ 45,958	$ 70,252	$ 23,750	$ 23,750
Expenses of Non-Utility Operations		$ (59,306)	$ (53,080)	$ (39,817)	$ (67,382)	$ (15,335)	$ (15,335)
Expenses of Non-Utility Operations		$ -	$ -	$ -		$ -	$ -
Miscellaneous Non-Operating Income	$ 124,494	$ 182,056	$ 251,896	$ 277,307	$ 266,934	$ 288,500	$ 288,500
Rate-Payer Benefit Including Interest		$ -	$ -	$ -		$ -	$ -
Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest and Dividend Income	$ 130,000	$ 159,335	$ 178,369	$ 747,158	$ 134,685	$ 78,000	$ 99,492
Total	**$ 1,497,790**	**$ 1,388,672**	**$ 2,046,469**	**$ 2,658,379**	**$ 1,800,565**	**$ 1,803,780**	**$ 1,778,000**

Appendix F – 2013 PILS (Updated)

2013 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	Rev Def	2,613,495
Tax Adj to Accounting Income	Rev Def	(2,758,339)
Taxable Income		**(144,844)**
Combined Income Tax Rate	PILs Rates	0.000%
Total Income Taxes		**-**
Investment Tax Credits		
Apprentice Tax Credits		
Other Tax Credits (SBD)		-
Total PILs		**-**

2013 Total Taxes

Description	Tax Payable
Total PILs	-
PILs including Capital Taxes	-

Appendix G – 2013 Cost of Capital (Updated)

DEBT AND CAPITAL COST STRUCTURE

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Average Principal	Term (Years)	Rate%	Interest Cost
Promissory Note	The Corporation of the City of Thunder Bay**	Y	September 2011	26,490,500		0.00%	0
2012 Infrastructure Financing	Unknown	N	May 2013	3,866,667	30	4.12%	159,307
2013 Infrastructure Financing	Unknown	N	September 2013	2,050,000	30	4.12%	84,460
Smart Meter Financing in Rate Base	TD Commercial Bank	N	Jan. 1, 2012	6,688,761	15	5.27%	352,498
			2013 Total Long Term Debt	39,095,928	**Total Interest Cost for 2013**		596,264
						Weighted Debt Cost Rate for 2013	1.53%

**The Promissory Note for the City of Thunder Bay will be updated to reflect conversion of $7,000,000 of the debt to equity.

Appendix H – 2013 Revenue Deficiency (Updated)

Thunder Bay Hydro Electricity Distribution Inc.
Revenue Deficiency Determination

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**737,237**
Distribution Revenue	21,252,629	18,473,376	18,473,376
Other Operating Revenue (Net)	1,213,545	1,778,000	1,778,000
Total Revenue	**22,466,174**	**20,251,375**	**20,988,613**
Costs and Expenses			
Administrative & General, Billing & Collecting	6,628,425	6,737,570	6,737,570
Operation & Maintenance	6,644,694	7,538,230	7,538,230
Depreciation & Amortization	6,786,257	3,200,647	3,200,647
Charitable Donation (LEAP)	332,080	24,200	24,200
Deemed Interest	293,824	874,470	874,470
Total Costs and Expenses	**20,685,279**	**18,375,117**	**18,375,117**
Utility Income Before Income Taxes	**1,780,894**	**1,876,258**	**2,613,495**
Income Taxes:			
Corporate Income Taxes	472,822	-	-
Total Income Taxes	**472,822**	**0**	**0**
Utility Net Income	**1,308,072**	**1,876,258**	**2,613,495**
Income Tax Expense Calculation:			
Accounting Income	1,780,894	1,876,258	2,613,495
Tax Adjustments to Accounting Income	607,114	(2,758,339)	(2,758,339)
Taxable Income	**2,388,008**	(882,081)	(144,844)
Income Tax Before Tax Credits	**632,822**	**0**	0
Tax Credits	**160,000**	**0**	**0**
Income Tax Expense	472,822	0	0
Tax Rate Refecting Tax Credits	26.50%	0.00%	0.00%
Actual Return on Rate Base:			
Rate Base	84,657,458	93,339,122	93,339,122
Interest Expense	293,824	874,470	874,470
Net Income	1,308,072	1,876,258	2,613,495
Total Actual Return on Rate Base	**1,601,896**	**2,750,728**	**3,487,965**
Actual Return on Rate Base	1.89%	2.95%	3.74%
Required Return on Rate Base:			
Rate Base	84,657,458	93,339,122	93,339,122
Return Rates:			
Return on Debt (Weighted)	0.58%	1.56%	1.56%
Return on Equity	3.75%	7.00%	7.00%
Deemed Interest Expense	293,824	874,470	874,470
Return On Equity	1,269,862	2,613,495	2,613,495
Total Return	**1,563,686**	**3,487,965**	**3,487,965**
Expected Return on Rate Base	1.85%	3.74%	3.74%
Revenue Deficiency After Tax	**(38,210)**	**737,237**	**(0)**
Revenue Deficiency Before Tax	**(51,987)**	**737,237**	**(0)**

Appendix I – Proposed 2013 Schedule of Rates and Charges (Updated)

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0167

RESIDENTIAL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.63
Smart Meter Disposition - Effective Until April 30, 2014	$	-1.58
Stranded Asset Rate Rider - Effective Until April 30, 2014	$	2.28
Distribution Volumetric Rate	$/kWh	0.0122
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0029
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.0020
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0167

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	25.96
Smart Meter Disposition - Effective Until April 30, 2014	$	4.19
Stranded Asset Rate Rider - Effective Until April 30, 2014	$	6.29
Distribution Volumetric Rate	$/kWh	0.0134
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0035
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.00200
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0167

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	195.33
Distribution Volumetric Rate	$/kW	2.4857
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.46
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.7802
Retail Transmission Rate – Network Service Rate	$/kW	2.4536
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.6027
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6885
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8662

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0167

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	2,794.55
Distribution Volumetric Rate	$/kW	2.2079
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.3535
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.7057
Retail Transmission Rate – Network Service Rate	$/kW	2.6027
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8662

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0167

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.75
Distribution Volumetric Rate	$/kWh	0.0099
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0036
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.00200
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

EB-2012-0167

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SENTINEL LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.66
Distribution Volumetric Rate	$/kW	5.3399
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	1.1274
Retail Transmission Rate – Network Service Rate	$/kW	1.8599
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3327

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.
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Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0167

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1.11
Distribution Volumetric Rate	$/kW	6.6959
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.3424
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.7100
Retail Transmission Rate – Network Service Rate	$/kW	1.8503
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3053

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
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EB-2012-0167

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be notedthat this schedule does not list any charges, assessments, or credits that are required by law to beinvoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
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Implementation Date May 1, 2013

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EB-2012-0167

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment	$	30.00
Service Call - Customer-owned Equipment - After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles - per pole/year	$	22.35

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

EB-2012-0167

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Secondary Metered Customers - Cusomers < 5,000 (RS, GU, GC, GS, G3, G8, M3, ST)	1.0342
Primary Metered Customers - Customers < 5,000 (GP, G1, G2, G9, M1, M2)	1.0239

Appendix J - Customer Impact – Residential (Updated)

Customer Class: **Residential**

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.8500	1	$ 9.85	$ 12.6300	1	$ 12.63	$ 2.78	28.22%
Smart Meter Incremental Rev Rec	Monthly	$ 1.8667	1	$ 1.87	$ -	1	$ -	$ (1.87)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0124	800	$ 9.92	$ 0.0122	800	$ 9.76	$ (0.16)	(1.61%)
Smart Meter Disposition Rider	Monthly	$ (1.3167)	1	$ (1.32)	$ (1.3167)	1	$ (1.32)	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.00004	800	$ 0.03	$ -	800	$ -	$ (0.03)	(100.00%)
Stranded Asset Rate Rider	Monthly	$ -	1	$ -	$ 2.2800	1	$ 2.28	$ 2.28	
Sub-Total A				$ 20.35			$ 23.35	**$ 3.00**	**14.75%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0034)	800	$ (2.72)	$ (0.0029)	800	$ (2.32)	$ 0.40	(14.71%)
Tax Charge Rate Rider	per kWh	$ (0.0003)	800	$ (0.24)		800	$ -	$ 0.24	(100.00%)
						1	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.39**			**$ 21.03**	**$ 3.64**	**20.94%**
RTSR - Network	per kWh	$ 0.0064	836	$ 5.35	$ 0.0065	827	$ 5.38	$ 0.03	0.53%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	836	$ 4.10	$ 0.0047	827	$ 3.89	$ (0.21)	(5.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 30.30**	**$ 3.46**	**12.90%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	836	$ 4.35	$ 0.0044	827	$ 3.64	$ (0.71)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	836	$ 0.92	$ 0.0012	827	$ 0.99	$ 0.07	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	836	$ 5.85	$ 0.0070	827	$ 5.79	$ (0.06)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	535	$ 33.70	$ 0.0630	530	$ 33.36	$ (0.34)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	150	$ 14.89	$ 0.0990	149	$ 14.74	$ (0.15)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	150	$ 17.75	$ 0.1180	149	$ 17.57	$ (0.18)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 38.20**			**$ 40.97**	**$ 2.77**	**7.25%**
HST		13%		$ 4.97	13%		$ 5.33	$ 0.36	7.25%
Total Bill (including HST)				$ 43.17			$ 46.30	$ 3.13	7.25%
Ontario Clean Energy Benefit [1]				$ (4.32)			$ (4.63)	$ (0.31)	7.18%
Total Bill on RPP (including OCEB)				**$ 38.85**			**$ 41.67**	**$ 2.82**	**7.26%**
Total Bill on TOU (before Taxes)				**$ 104.55**			**$ 106.65**	**$ 2.10**	**2.01%**
HST		13%		$ 13.59	13%		$ 13.86	$ 0.27	2.01%
Total Bill (including HST)				$ 118.14			$ 120.51	$ 2.37	2.01%
Ontario Clean Energy Benefit [1]				$ (11.81)			$ (12.05)	$ (0.24)	2.03%
Total Bill on TOU (including OCEB)				**$ 106.33**			**$ 108.46**	**$ 2.13**	**2.00%**
Loss Factor (%)		4.48%			3.42%				

Appendix J - Customer Impact - General Service < 50 kW (Updated)

Customer Class: **General Service Less Than 50 kW**

Consumption 2000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 17.8400	1	$ 17.84	$ 25.9600	1	$ 25.96	$ 8.12	45.52%
Smart Meter Incremental Rev Rec	Monthly	$ 6.8417	1	$ 6.84	$ -	1	$ -	$ (6.84)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0130	2000	$ 26.00	$ 0.0134	2000	$ 26.80	$ 0.80	3.08%
Smart Meter Disposition Rider	Monthly	$ 3.4917	1	$ 3.49	$ 3.4917	1	$ 3.49	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	$ (0.40)	(100.00%)
Stranded Asset Rate Rider	Monthly		1	$ -	$ 6.2900	1	$ 6.29	$ 6.29	
Sub-Total A				$ 54.57			$ 62.54	**$ 7.97**	**14.60%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0030)	2000	$ (6.00)	$ (0.0035)	2000	$ (7.00)	$ (1.00)	16.67%
Tax Charge Rate Rider	per kWh	$ (0.0002)	2000	$ (0.40)	$ -	2000	$ -	$ 0.40	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.17**			**$ 55.54**	**$ 7.37**	**15.30%**
RTSR - Network	per kWh	$ 0.0061	2090	$ 12.75	$ 0.0062	2068	$ 12.82	$ 0.08	0.61%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2090	$ 9.61	$ 0.0044	2068	$ 9.10	$ (0.51)	(5.32%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 70.53**			**$ 77.47**	**$ 6.93**	**9.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2090	$ 10.87	$ 0.0044	2068	$ 9.10	$ (1.76)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2090	$ 2.30	$ 0.0012	2068	$ 2.48	$ 0.18	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 98.57**			**$ 103.78**	**$ 5.20**	**5.28%**
HST		13%		$ 12.81	13%		$ 13.49	$ 0.68	5.28%
Total Bill (including HST)				$ 111.39			$ 117.27	$ 5.88	5.28%
Ontario Clean Energy Benefit [1]				$ (11.14)			$ (11.73)	$ (0.59)	5.30%
Total Bill on RPP (including OCEB)				**$ 100.25**			**$ 105.54**	**$ 5.29**	**5.28%**
Total Bill on TOU (before Taxes)				**$ 264.45**			**$ 267.97**	**$ 3.52**	**1.33%**
HST		13%		$ 34.38	13%		$ 34.84	$ 0.46	1.33%
Total Bill (including HST)				$ 298.82			$ 302.80	$ 3.98	1.33%
Ontario Clean Energy Benefit [1]				$ (29.88)			$ (30.28)	$ (0.40)	1.34%
Total Bill on TOU (including OCEB)				**$ 268.94**			**$ 272.52**	**$ 3.58**	**1.33%**

	Current	Proposed
Loss Factor (%)	4.48%	3.42%

Appendix J - Customer Impact - General Service > 50 kW to 999 kW (Updated)

Customer Class: General Service 50 to to 999 kW

Consumption 100 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 195.3300	1	$ 195.33	$ (46.45)	(19.21%)
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 2.4857	100	$ 248.57	$ 112.54	82.73%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 443.90	**$ 66.09**	**17.49%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4600)	100	$ (146.00)	$ (54.73)	59.96%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 375.92**	**$ 103.99**	**38.24%**
RTSR - Network	per kW	$ 2.4300	104	$ 253.89	$ 2.4536	103	$ 253.75	$ (0.14)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.7458	104	$ 182.40	$ 1.6885	103	$ 174.62	$ (7.78)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 708.22**			**$ 804.30**	**$ 96.08**	**13.57%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	31344	$ 162.99	$ 0.0044	31026	$ 136.51	$ (26.47)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	31344	$ 34.48	$ 0.0012	31026	$ 37.23	$ 2.75	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	31344	$ 219.41	$ 0.0070	31026	$ 217.18	$ (2.23)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	20060	$ 1,263.79	$ 0.0630	19857	$ 1,250.97	$ (12.82)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	5642	$ 558.55	$ 0.0990	5585	$ 552.88	$ (5.67)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	5642	$ 665.75	$ 0.1180	5585	$ 658.99	$ (6.75)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 1,125.34**			**$ 1,195.47**	**$ 70.13**	**6.23%**
HST		13%		$ 146.29	13%		$ 155.41	$ 9.12	6.23%
Total Bill (including HST)				$ 1,271.64			$ 1,350.89	$ 79.25	6.23%
Ontario Clean Energy Benefit [1]				$ (127.16)			$ (135.09)	$ (7.93)	6.24%
Total Bill on RPP (including OCEB)				**$ 1,144.48**			**$ 1,215.80**	**$ 71.32**	**6.23%**
Total Bill on TOU (before Taxes)				**$ 3,613.43**			**$ 3,658.32**	**$ 44.89**	**1.24%**
HST		13%		$ 469.75	13%		$ 475.58	$ 5.84	1.24%
Total Bill (including HST)				$ 4,083.18			$ 4,133.90	$ 50.72	1.24%
Ontario Clean Energy Benefit [1]				$ (408.32)			$ (413.39)	$ (5.07)	1.24%
Total Bill on TOU (including OCEB)				**$ 3,674.86**			**$ 3,720.51**	**$ 45.65**	**1.24%**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

Customer Class: **General Service 50 to to 999 kW Interval Metered**

Consumption 100 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 195.3300	1	$ 195.33	$ (46.45)	(19.21%)
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 2.4857	100	$ 248.57	$ 112.54	82.73%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 443.90	**$ 66.09**	**17.49%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4600)	100	$ (146.00)	$ (54.73)	59.96%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 375.92**	**$ 103.99**	**38.24%**
RTSR - Network	per kW	$ 2.5777	104	$ 269.32	$ 2.6027	103	$ 269.17	$ (0.15)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	104	$ 201.59	$ 1.8662	103	$ 193.00	$ (8.59)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 742.84**			**$ 838.09**	**$ 95.25**	**12.82%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	31344	$ 162.99	$ 0.0044	31026	$ 136.51	$ (26.47)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	31344	$ 34.48	$ 0.0012	31026	$ 37.23	$ 2.75	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	31344	$ 219.41	$ 0.0070	31026	$ 217.18	$ (2.23)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	20060	$ 1,263.79	$ 0.0630	19857	$ 1,250.97	$ (12.82)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	5642	$ 558.55	$ 0.0990	5585	$ 552.88	$ (5.67)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	5642	$ 665.75	$ 0.1180	5585	$ 658.99	$ (6.75)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 1,159.97**			**$ 1,229.27**	**$ 69.30**	**5.97%**
HST		13%		$ 150.80	13%		$ 159.81	$ 9.01	5.97%
Total Bill (including HST)				$ 1,310.76			$ 1,389.08	$ 78.31	5.97%
Ontario Clean Energy Benefit [1]				$ (131.08)			$ (138.91)	$ (7.83)	5.97%
Total Bill on RPP (including OCEB)				**$ 1,179.68**			**$ 1,250.17**	**$ 70.48**	**5.97%**
Total Bill on TOU (before Taxes)				**$ 3,648.05**			**$ 3,692.12**	**$ 44.06**	**1.21%**
HST		13%		$ 474.25	13%		$ 479.97	$ 5.73	1.21%
Total Bill (including HST)				$ 4,122.30			$ 4,172.09	$ 49.79	1.21%
Ontario Clean Energy Benefit [1]				$ (412.23)			$ (417.21)	$ (4.98)	1.21%
Total Bill on TOU (including OCEB)				**$ 3,710.07**			**$ 3,754.88**	**$ 44.81**	**1.21%**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

Appendix J - Customer Impact - General Service > 1000 kW to 4999 kW (Updated)

Customer Class: **General Service 1,000 to 4,999 kW**

Consumption 2000 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$2,794.5500	1	$ 2,794.55	$ 2,794.5500	1	$ 2,794.55	$ -	0.00%
Distribution Volumetric Rate	per kW	$ 2.2314	2000	$ 4,462.80	$ 2.2079	2000	$ 4,415.80	$ (47.00)	(1.05%)
Sub-Total A				$ 7,257.35			$ 7,210.35	**$ (47.00)**	**(0.65%)**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.7755)	2000	$ (1,551.00)	$ (1.3535)	2000	$ (2,707.00)	$ (1,156.00)	74.53%
Global Adjustment Rate Rider	per kW	$ (0.0924)	2000	$ (184.80)	$ 0.7057	2000	$ 1,411.40	$ 1,596.20	(863.74%)
Tax Charge Rate Rider	per kW	$ (0.0371)	2000	$ (74.20)	$ -	2000	$ -	$ 74.20	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,447.35**			**$ 5,914.75**	**$ 467.40**	**8.58%**
RTSR - Network	per kW	$ 2.5777	2090	$ 5,386.36	$ 2.6027	2068	$ 5,383.42	$ (2.94)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	2090	$ 4,031.88	$ 1.8662	2068	$ 3,860.05	$ (171.84)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,865.60**			**$ 15,158.22**	**$ 292.63**	**1.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	754346	$ 3,922.60	$ 0.0044	746692	$ 3,285.45	$ (637.15)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	754346	$ 829.78	$ 0.0012	746692	$ 896.03	$ 66.25	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	754346	$ 5,280.42	$ 0.0070	746692	$ 5,226.85	$ (53.57)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	482781	$ 30,415.21	$ 0.0630	477883	$ 30,106.64	$ (308.58)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	135782	$ 13,442.44	$ 0.0990	134405	$ 13,306.06	$ (136.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	135782	$ 16,022.30	$ 0.1180	134405	$ 15,859.75	$ (162.55)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 24,898.64**			**$ 24,566.80**	**$ (331.84)**	**(1.33%)**
HST		13%		$ 3,236.82	13%		$ 3,193.68	$ (43.14)	(1.33%)
Total Bill (including HST)				$ 28,135.47			$ 27,760.48	$ (374.98)	(1.33%)
Ontario Clean Energy Benefit [1]				$ (2,813.55)			$ (2,776.05)	$ 37.50	(1.33%)
Total Bill on RPP (including OCEB)				**$ 25,321.92**			**$ 24,984.43**	**$ (337.48)**	**(1.33%)**
Total Bill on TOU (before Taxes)				**$ 84,778.60**			**$ 83,839.24**	**$ (939.36)**	**(1.11%)**
HST		13%		$ 11,021.22	13%		$ 10,899.10	$ (122.12)	(1.11%)
Total Bill (including HST)				$ 95,799.81			$ 94,738.34	$ (1,061.47)	(1.11%)
Ontario Clean Energy Benefit [1]				$ (9,579.98)			$ (9,473.83)	$ 106.15	(1.11%)
Total Bill on TOU (including OCEB)				**$ 86,219.83**			**$ 85,264.51**	**$ (955.32)**	**(1.11%)**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

Appendix J - Customer Impact – Unmetered Scattered Load (Updated)

Customer Class: **Umetered Scattered Load**

Consumption 150 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 8.9100	1	$ 8.91	$ 6.7500	1	$ 6.75	$ (2.16)	(24.24%)
Distribution Volumetric Rate	per kWh	$ 0.0130	150	$ 1.95	$ 0.0099	150	$ 1.49	$ (0.47)	(23.85%)
Sub-Total A				$ 10.86			$ 8.24	**$ (2.63)**	**(24.17%)**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0044)	150	$ (0.66)	$ (0.0036)	150	$ (0.54)	$ 0.12	(18.18%)
Tax Charge Rate Rider	per kWh	$ (0.0005)	150	$ (0.08)	$ -	150	$ -	$ 0.08	(100.00%)
Smart Meter Entity Charge					$ -	150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.13**			**$ 7.70**	**$ (2.43)**	**(24.00%)**
RTSR - Network	per kWh	$ 0.0061	157	$ 0.96	$ 0.0062	155	$ 0.96	$ 0.01	0.61%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	157	$ 0.72	$ 0.0044	155	$ 0.68	$ (0.04)	(5.32%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.80**			**$ 9.34**	**$ (2.46)**	**(20.87%)**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157	$ 0.81	$ 0.0044	155	$ 0.68	$ (0.13)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	157	$ 0.17	$ 0.0012	155	$ 0.19	$ 0.01	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157	$ 1.10	$ 0.0070	155	$ 1.09	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	100	$ 6.32	$ 0.0630	99	$ 6.25	$ (0.06)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	28	$ 2.79	$ 0.0990	28	$ 2.76	$ (0.03)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	28	$ 3.33	$ 0.1180	28	$ 3.29	$ (0.03)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 14.14**			**$ 11.54**	**$ (2.59)**	**(18.34%)**
HST		13%		$ 1.84	13%		$ 1.50	$ (0.34)	(18.34%)
Total Bill (including HST)				$ 15.97			$ 13.04	$ (2.93)	(18.34%)
Ontario Clean Energy Benefit [1]				$ (1.60)			$ (1.30)	$ 0.30	(18.75%)
Total Bill on RPP (including OCEB)				**$ 14.37**			**$ 11.74**	**$ (2.63)**	**(18.29%)**
Total Bill on TOU (before Taxes)				**$ 26.58**			**$ 23.86**	**$ (2.72)**	**(10.23%)**
HST		13%		$ 3.45	13%		$ 3.10	$ (0.35)	(10.23%)
Total Bill (including HST)				$ 30.03			$ 26.96	$ (3.07)	(10.23%)
Ontario Clean Energy Benefit [1]				$ (3.00)			$ (2.70)	$ 0.30	(10.00%)
Total Bill on TOU (including OCEB)				**$ 27.03**			**$ 24.26**	**$ (2.77)**	**(10.25%)**

	Current	Proposed
Loss Factor (%)	4.48%	3.42%

Appendix J - Customer Impact – Sentinel Lighting (Updated)

Customer Class: **Sentinel Lighting**

Consumption 0.2 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 6.4000	1	$ 6.40	$ 6.6600	1	$ 6.66	$ 0.26	4.06%
Distribution Volumetric Rate	per kW	$ 5.1350	0.2	$ 1.03	$ 5.3399	0.2	$ 1.07	$ 0.04	3.99%
Sub-Total A				$ 7.43			$ 7.73	**$ 0.30**	**4.05%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (2.4061)	0.2	$ (0.48)	$ 1.1274	0.2	$ 0.23	$ 0.71	(146.86%)
Tax Charge Rate Rider	per kW	$ (0.4698)	0.2	$ (0.09)		0.2	$ -	$ 0.09	(100.00%)
Smart Meter Entity Charge						0.2	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.85**			**$ 7.95**	**$ 1.10**	**16.08%**
RTSR - Network	per kW	$ 1.8420	0	$ 0.38	$ 1.8599	0	$ 0.38	$ (0.00)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.3779	0	$ 0.29	$ 1.3327	0	$ 0.28	$ (0.01)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.52**			**$ 8.61**	**$ 1.09**	**14.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	73	$ 0.38	$ 0.0044	72	$ 0.32	$ (0.06)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	73	$ 0.08	$ 0.0012	72	$ 0.09	$ 0.01	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	73	$ 0.51	$ 0.0070	72	$ 0.51	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	47	$ 2.95	$ 0.0630	46	$ 2.92	$ (0.03)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	13	$ 1.30	$ 0.0990	13	$ 1.29	$ (0.01)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	13	$ 1.55	$ 0.1180	13	$ 1.54	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 8.75**			**$ 9.78**	**$ 1.03**	**11.76%**
HST		13%		$ 1.14	13%		$ 1.27	$ 0.13	11.76%
Total Bill (including HST)				$ 9.88			$ 11.05	$ 1.16	11.76%
Ontario Clean Energy Benefit [1]				$ (0.99)			$ (1.10)	$ (0.11)	11.11%
Total Bill on RPP (including OCEB)				**$ 8.89**			**$ 9.95**	**$ 1.05**	**11.83%**
Total Bill on TOU (before Taxes)				**$ 14.55**			**$ 15.52**	**$ 0.97**	**6.66%**
HST		13%		$ 1.89	13%		$ 2.02	$ 0.13	6.66%
Total Bill (including HST)				$ 16.44			$ 17.54	$ 1.10	6.66%
Ontario Clean Energy Benefit [1]				$ (1.64)			$ (1.75)	$ (0.11)	6.71%
Total Bill on TOU (including OCEB)				**$ 14.80**			**$ 15.79**	**$ 0.99**	**6.66%**

Loss Factor (%)	4.48%	3.42%

Appendix J - Customer Impact – Streetlighting (Updated)

Customer Class: **Street Lighting**

Consumption **2400** **kW**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 2.1600	1	$ 2.16	$ 1.1100	1	$ 1.11	$ (1.05)	(48.61%)
Distribution Volumetric Rate	per kW	$ 13.0610	2400	$ 31,346.40	$ 6.6959	2400	$ 16,070.16	$ (15,276.24)	(48.73%)
Sub-Total A				$ 31,348.56			$ 16,071.27	**$ (15,277.29)**	**(48.73%)**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (1.5474)	2400	$ (3,713.76)	$ (1.3424)	2400	$ (3,221.76)	$ 492.00	(13.25%)
Global Adjustment Rate Rider	per kW	$ (0.1097)	2400	$ (263.28)	$ 0.7100	2400	$ 1,704.00	$ 1,967.28	(747.22%)
Tax Charge Rate Rider	per kW	$ (0.2863)	2400	$ (687.12)	$ -	2400	$ -	$ 687.12	(100.00%)
Smart Meter Entity Charge						2400	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,684.40**			**$ 14,553.51**	**$ (12,130.89)**	**(45.46%)**
RTSR - Network	per kW	$ 1.8325	2508	$ 4,595.03	$ 1.8503	2482	$ 4,592.59	$ (2.44)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.3496	2508	$ 3,384.15	$ 1.3053	2482	$ 3,239.86	$ (144.29)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 34,663.58**			**$ 22,385.96**	**$ (12,277.62)**	**(35.42%)**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	940320	$ 4,889.66	$ 0.0044	930780	$ 4,095.43	$ (794.23)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	940320	$ 1,034.35	$ 0.0012	930780	$ 1,116.94	$ 82.58	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	940320	$ 6,582.24	$ 0.0070	930780	$ 6,515.46	$ (66.78)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2	per kWh	$ 0.0870		$ -	$ 0.0870		$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	601805	$ 37,913.70	$ 0.0630	595699	$ 37,529.05	$ (384.65)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	169258	$ 16,756.50	$ 0.0990	167540	$ 16,586.50	$ (170.00)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	169258	$ 19,972.40	$ 0.1180	167540	$ 19,769.77	$ (202.63)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 47,170.09**			**$ 34,114.04**	**$ (13,056.05)**	**(27.68%)**
HST		13%		$ 6,132.11	13%		$ 4,434.83	$ (1,697.29)	(27.68%)
Total Bill (including HST)				$ 53,302.20			$ 38,548.86	$ (14,753.33)	(27.68%)
Ontario Clean Energy Benefit [1]				$ (5,330.22)			$ (3,854.89)	$ 1,475.33	(27.68%)
Total Bill on RPP (including OCEB)				**$ 47,971.98**			**$ 34,693.97**	**$ (13,278.00)**	**(27.68%)**
Total Bill on TOU (before Taxes)				**$ 121,812.69**			**$ 107,999.36**	**$ (13,813.33)**	**(11.34%)**
HST		13%		$ 15,835.65	13%		$ 14,039.92	$ (1,795.73)	(11.34%)
Total Bill (including HST)				$ 137,648.34			$ 122,039.27	$ (15,609.06)	(11.34%)
Ontario Clean Energy Benefit [1]				$ (13,764.83)			$ (12,203.93)	$ 1,560.90	(11.34%)
Total Bill on TOU (including OCEB)				**$ 123,883.51**			**$ 109,835.34**	**$ (14,048.16)**	**(11.34%)**

	Current Board-Approved	Proposed
Loss Factor (%)	4.48%	3.42%

Appendix J - Customer Impact – Microfit (Updated)

Customer Class: **Microfit**

Consumption 5 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 5.2500	1	$ 5.25	$ 5.4000	1	$ 5.40	$ 0.15	2.86%
Sub-Total A				$ 5.25			$ 5.40	**$ 0.15**	**2.86%**
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
						5	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
RTSR - Network			5	$ -		5	$ -	$ -	
RTSR - Line and Transformation Connection			5	$ -		5	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
Wholesale Market Service Charge (WMSC)			5	$ -		5	$ -	$ -	
Rural and Remote Rate Protection (RRRP)			5	$ -		5	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 1			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 2			0	$ -		0	$ -	$ -	
TOU - Off Peak			3	$ -		3	$ -	$ -	
TOU - Mid Peak			1	$ -		1	$ -	$ -	
TOU - On Peak			1	$ -		1	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on RPP (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**
Total Bill on TOU (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on TOU (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**

Loss Factor (%)	4.48%	3.42%

Appendix K – Cost Allocation Sheet O1 (Updated)

Rate Base Assets		Total	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$18,473,376	$10,522,811	$3,038,597	$2,489,053	$1,577,040	$754,028	$14,701	$77,146
mi	Miscellaneous Revenue (mi)	$1,778,000	$1,129,610	$255,797	$266,564	$90,251	$29,114	$1,961	$4,703
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$20,251,375	$11,652,421	$3,294,394	$2,755,617	$1,667,291	$783,142	$16,662	$81,849
	Factor required to recover deficiency (1 + D)	1.0399							
	Distribution Revenue at Status Quo Rates	$19,210,613	$10,942,756	$3,159,862	$2,588,386	$1,639,977	$784,119	$15,288	$80,224
	Miscellaneous Revenue (mi)	$1,778,000	$1,129,610	$255,797	$266,564	$90,251	$29,114	$1,961	$4,703
	Total Revenue at Status Quo Rates	$20,988,612	$12,072,366	$3,415,659	$2,854,950	$1,730,228	$813,233	$17,248	$84,928
	Expenses								
di	Distribution Costs (di)	$7,290,355	$3,913,210	$1,170,660	$1,457,165	$577,593	$143,411	$6,692	$21,623
cu	Customer Related Costs (cu)	$2,382,569	$1,777,870	$299,369	$266,780	$32,367	$5,446	$273	$464
ad	General and Administration (ad)	$4,363,507	$2,565,305	$663,858	$778,314	$275,399	$67,451	$3,160	$10,021
dep	Depreciation and Amortization (dep)	$3,464,216	$1,872,586	$603,377	$673,960	$241,471	$60,399	$2,861	$9,562
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$874,470	$480,772	$141,634	$167,935	$63,044	$17,472	$862	$2,752
	Total Expenses	$18,375,117	$10,609,743	$2,878,898	$3,344,154	$1,189,874	$294,179	$13,846	$44,422
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,613,495	$1,436,865	$423,295	$501,901	$188,417	$52,217	$2,575	$8,226
	Revenue Requirement (includes NI)	$20,988,612	$12,046,608	$3,302,193	$3,846,055	$1,378,292	$346,396	$16,421	$52,647
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$174,419,224	$97,687,820	$29,261,795	$32,314,362	$11,055,645	$3,396,795	$167,353	$535,454
gp	General Plant - Gross	$16,319,680	$9,092,158	$2,666,254	$3,072,133	$1,091,709	$329,013	$16,408	$52,004
accum dep	Accumulated Depreciation	($95,054,448)	($53,351,852)	($16,266,682)	($17,439,399)	($5,832,639)	($1,794,445)	($87,285)	($282,146)
co	Capital Contribution	($16,658,215)	($9,953,289)	($2,856,624)	($2,784,845)	($636,714)	($351,766)	($18,541)	($56,436)
	Total Net Plant	$79,026,240	$43,474,837	$12,804,743	$15,162,251	$5,678,000	$1,579,597	$77,936	$248,876
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$96,062,659	$34,122,676	$13,198,680	$28,967,660	$18,434,633	$1,123,318	$12,303	$203,388
	OM&A Expenses	$14,036,431	$8,256,386	$2,133,887	$2,502,259	$885,359	$216,308	$10,124	$32,107
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$110,099,090*	*$42,379,062*	*$15,332,567*	*$31,469,919*	*$19,319,993*	*$1,339,627*	*$22,427*	*$235,496*
	Working Capital	$14,312,882	$5,509,278	$1,993,234	$4,091,089	$2,511,599	$174,151	$2,915	$30,614
	Total Rate Base	$93,339,122	$48,984,115	$14,797,977	$19,253,340	$8,189,599	$1,753,748	$80,852	$279,490
		Rate Base Input equals Output							
	Equity Component of Rate Base	$37,335,649	$19,593,646	$5,919,191	$7,701,336	$3,275,840	$701,499	$32,341	$111,796
	Net Income on Allocated Assets	$2,613,495	$1,462,623	$536,761	($489,204)	$540,354	$519,054	$3,402	$40,506
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,613,495	$1,462,623	$536,761	($489,204)	$540,354	$519,054	$3,402	$40,506
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	100.21%	103.44%	74.23%	125.53%	234.77%	105.04%	161.31%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($737,237)	($394,187)	($7,799)	($1,090,438)	$289,000	$436,745	$240	$29,202
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$25,758	$113,465	($991,104)	$351,936	$466,837	$827	$32,280
	RETURN ON EQUITY COMPONENT OF RATE BASE	7.00%	7.46%	9.07%	-6.35%	16.50%	73.99%	10.52%	36.23%

Appendix L– Revenue Requirement Work Form (Updated)

Version 3.00

Rate Year:

Utility Name	Thunder Bay Hydro Electricity Distribution Inc.
Service Territory	Thunder Bay
Assigned EB Number	EB-2012-0167
Name and Title	Jenni Pajala, Supervisor of Regulatory Affairs
Phone Number	807-343-1016
Email Address	japajala@tbhydro.on.ca

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$174,982,258		($1,091,563.88)	$ 173,890,694			$173,890,694	
	Accumulated Depreciation (average)	($95,076,084)	(5)	$211,631.27	($94,864,453)			($94,864,453)	
	Allowance for Working Capital:								
	Controllable Expenses	$14,418,846		($382,415)	$ 14,036,431			$14,036,431	
	Cost of Power	$97,020,439		($957,782)	$ 96,062,657			$96,062,657	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		13.00%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$18,341,720		$131,656	$18,473,376		$0	$18,473,376	
	Distribution Revenue at Proposed Rates	$19,901,055		($690,442)	$19,210,613		$0	$19,210,613	
	Other Revenue:								
	Specific Service Charges	$267,807		$0	$267,807		$0	$267,807	
	Late Payment Charges	$297,000		$0	$297,000		$0	$297,000	
	Other Distribution Revenue	$856,920		$3,986	$860,906		$0	$860,906	
	Other Income and Deductions	$330,008		$22,279	$352,287		$0	$352,287	
	Total Revenue Offsets	$1,751,736	(7)	$26,265	$1,778,000		$0	$1,778,000	
	Operating Expenses:								
	OM+A Expenses	$14,682,415		($382,415)	$ 14,300,000			$14,300,000	
	Depreciation/Amortization	$3,247,244	(10)	($46,596)	$ 3,200,647			$3,200,647	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,831,251)	(3)		($2,758,339)			($2,758,339)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$ -			$ -			$ -	
	Income taxes (grossed up)	$ -			$ -			$ -	
	Federal tax (%)	0.00%	(12)		0.00%			0.00%	
	Provincial tax (%)	0.00%	(13)		0.00%			0.00%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	1.89%			1.53%			1.53%	
	Short-term debt Cost Rate (%)	2.08%			2.07%			2.07%	
	Common Equity Cost Rate (%)	7.00%			7.00%			7.00%	
	Prefered Shares Cost Rate (%)								
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	$ -	(11)	$0	$0	(11)	($0)	$ -	(11)

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(12) & (13) Inputted as 0% in order to force income tax payable as $0 for 2013 since taxable income is negative.

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$174,982,258	($1,091,564)	$173,890,694	$ -	$173,890,694
2	Accumulated Depreciation (average)	(3)	($95,076,084)	$211,631	($94,864,453)	$ -	($94,864,453)
3	Net Fixed Assets (average)	(3)	$79,906,174	($879,933)	$79,026,241	$ -	$79,026,241
4	Allowance for Working Capital	(1)	$14,487,107	($174,226)	$14,312,881	$ -	$14,312,881
5	**Total Rate Base**		$94,393,281	($1,054,158)	$93,339,122	$ -	$93,339,122

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$14,418,846	($382,415)	$14,036,431	$ -	$14,036,431
7	Cost of Power		$97,020,439	($957,782)	$96,062,657	$ -	$96,062,657
8	Working Capital Base		$111,439,285	($1,340,197)	$110,099,088	$ -	$110,099,088
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$14,487,107	($174,226)	$14,312,881	$ -	$14,312,881

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$19,901,055	($690,442)	$19,210,613	$ -	$19,210,613
2	Other Revenue (1)	$1,751,736	$26,265	$1,778,000	$ -	$1,778,000
3	Total Operating Revenues	$21,652,790	($664,177)	$20,988,613	$ -	$20,988,613
	Operating Expenses:					
4	OM+A Expenses	$14,682,415	($382,415)	$14,300,000	$ -	$14,300,000
5	Depreciation/Amortization	$3,247,244	($46,596)	$3,200,647	$ -	$3,200,647
6	Property taxes	$ -	$ -		$ -	
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$17,929,659	($429,011)	$17,500,647	$ -	$17,500,647
10	Deemed Interest Expense	$1,080,120	($205,650)	$874,470	$ -	$874,470
11	Total Expenses (lines 9 to 10)	$19,009,779	($634,661)	$18,375,117	$ -	$18,375,117
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -	$0	$0	($0)	$ -
13	**Utility income before income taxes**	$2,643,012	($29,516)	$2,613,496	$0	$2,613,496
14	Income taxes (grossed-up)	$ -	$ -	$ -	$ -	$ -
15	**Utility net income**	$2,643,012	($29,516)	$2,613,496	$0	$2,613,496

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$267,807	$ -	$267,807	$ -	$267,807
	Late Payment Charges	$297,000	$ -	$297,000	$ -	$297,000
	Other Distribution Revenue	$856,920	$3,986	$860,906	$ -	$860,906
	Other Income and Deductions	$330,008	$22,279	$352,287	$ -	$352,287
	Total Revenue Offsets	$1,751,736	$26,265	$1,778,000	$ -	$1,778,000

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,643,012	$2,613,495	$2,613,495
2	Adjustments required to arrive at taxable utility income	($2,831,251)	($2,758,339)	($2,758,339)
3	Taxable income	($188,239)	($144,844)	($144,844)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$52,860,237	1.89%	$1,001,585
2	Short-term Debt	4.00%	$3,775,731	2.08%	$78,535
3	**Total Debt**	60.00%	$56,635,968	1.91%	$1,080,120
	Equity				
4	Common Equity	40.00%	$37,757,312	7.00%	$2,643,012
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$37,757,312	7.00%	$2,643,012
7	**Total**	100.00%	$94,393,281	3.94%	$3,723,132
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$52,269,909	1.53%	$797,185
2	Short-term Debt	4.00%	$3,733,565	2.07%	$77,285
3	**Total Debt**	60.00%	$56,003,473	1.56%	$874,470
	Equity				
4	Common Equity	40.00%	$37,335,649	7.00%	$2,613,495
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$37,335,649	7.00%	$2,613,495
7	**Total**	100.00%	$93,339,122	3.74%	$3,487,965
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$52,269,909	1.53%	$797,185
9	Short-term Debt	4.00%	$3,733,565	2.07%	$77,285
10	**Total Debt**	60.00%	$56,003,473	1.56%	$874,470
	Equity				
11	Common Equity	40.00%	$37,335,649	7.00%	$2,613,495
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$37,335,649	7.00%	$2,613,495
14	**Total**	100.00%	$93,339,122	3.74%	$3,487,965

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,559,334		$737,236		$737,236
2	Distribution Revenue	$18,341,720	$18,341,720	$18,473,376	$18,473,377	$18,473,376	$18,473,377
3	Other Operating Revenue Offsets - net	$1,751,736	$1,751,736	$1,778,000	$1,778,000	$1,778,000	$1,778,000
4	**Total Revenue**	$20,093,456	$21,652,790	$20,251,376	$20,988,613	$20,251,376	$20,988,613
5	Operating Expenses	$17,929,659	$17,929,659	$17,500,647	$17,500,647	$17,500,647	$17,500,647
6	Deemed Interest Expense	$1,080,120	$1,080,120	$874,470	$874,470	$874,470	$874,470
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$0 **(2)**	$0	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$19,009,779	$19,009,779	$18,375,117	$18,375,117	$18,375,117	$18,375,117
9	**Utility Income Before Income Taxes**	$1,083,677	$2,643,012	$1,876,259	$2,613,496	$1,876,259	$2,613,496
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,831,251)	($2,831,251)	($2,758,339)	($2,758,339)	($2,758,339)	($2,758,339)
11	**Taxable Income**	($1,747,574)	($188,240)	($882,080)	($144,843)	($882,080)	($144,843)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,083,677	$2,643,012	$1,876,259	$2,613,496	$1,876,259	$2,613,496
16	**Utility Rate Base**	$94,393,281	$94,393,281	$93,339,122	$93,339,122	$93,339,122	$93,339,122
17	Deemed Equity Portion of Rate Base	$37,757,312	$37,757,312	$37,335,649	$37,335,649	$37,335,649	$37,335,649
18	Income/(Equity Portion of Rate Base)	2.87%	7.00%	5.03%	7.00%	5.03%	7.00%
19	Target Return - Equity on Rate Base	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
20	Deficiency/Sufficiency in Return on Equity	-4.13%	0.00%	-1.97%	0.00%	-1.97%	0.00%
21	Indicated Rate of Return	2.29%	3.94%	2.95%	3.74%	2.95%	3.74%
22	Requested Rate of Return on Rate Base	3.94%	3.94%	3.74%	3.74%	3.74%	3.74%
23	Deficiency/Sufficiency in Rate of Return	-1.65%	0.00%	-0.79%	0.00%	-0.79%	0.00%
24	Target Return on Equity	$2,643,012	$2,643,012	$2,613,495	$2,613,495	$2,613,495	$2,613,495
25	Revenue Deficiency/(Sufficiency)	$1,559,334	($0)	$737,236	$1	$737,236	$1
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,559,334 **(1)**		$737,236 **(1)**		$737,236 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$14,682,415		$14,300,000		$14,300,000	
2	Amortization/Depreciation	$3,247,244		$3,200,647		$3,200,647	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,080,120		$874,470		$874,470	
	Return on Deemed Equity	$2,643,012		$2,613,495		$2,613,495	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$0		$ -	
8	**Service Revenue Requirement (before Revenues)**	$21,652,791		$20,988,613		$20,988,613	
9	Revenue Offsets	$1,751,736		$1,778,000		$1,778,000	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$19,901,055		$19,210,612		$19,210,612	
11	Distribution revenue	$19,901,055		$19,210,613		$19,210,613	
12	Other revenue	$1,751,736		$1,778,000		$1,778,000	
13	**Total revenue**	$21,652,790		$20,988,613		$20,988,613	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	$1	(1)	$1	(1)

Notes

(1) Line 11 - Line 8

Appendix M – Throughput Revenue (Updated)

Customer Class	Customers/Connections	Consumption	Demand	Proposed Monthly Service Charge	Proposed Volumetric Rate	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	44,881	339,721,062		12.63	0.0122	$ 6,802,164	$ 4,144,597		$ 10,946,761	$ 10,942,756
GS < 50 kW	4,492	131,404,394		25.96	0.0134	$ 1,399,348	$ 1,760,819		$ 3,160,167	$ 3,159,862
GS >50 to 999 kW	515	288,398,369	783,589	195.33	2.4857	$ 1,207,139	$ 1,947,767	($70,602)	$ 3,084,305	$ 3,083,973
GS >1000 to 4999 kW	19	183,532,884	568,917	2,794.55	2.2079	$ 637,157	$ 1,256,112	($329,598)	$ 1,563,671	$ 1,563,699
Sentinel Lights	169	122,483	340	6.66	5.3399	$ 13,506	$ 1,816		$ 15,322	$ 15,288
Street Lighting	13,217	11,183,615	31,502	1.11	6.6959	$ 176,050	$ 210,934		$ 386,985	$ 386,561
Unmetered and Scattered	475	2,024,907		6.75	0.0099	$ 38,475	$ 20,047		$ 58,522	$ 58,473
Total	**63,768**	**956,387,714**	**1,384,348**			**$ 10,273,841**	**$ 9,342,091**	**($400,200)**	**$ 19,215,732**	**$ 19,210,613**