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ONTARIO ENERGY BOARD

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

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

APPLICATION

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

2. Hydro One Networks is applying to the Ontario Energy Board (the "Board"), pursuant to Section 78 of the *Ontario Energy Board Act*, *1998*, for an Order or Orders approving the customer rates for the distribution of electricity, to be effective on January 1, 2013.

3. The scope of this Application includes:

   - The review of Distribution rates effective January 1, 2013 based on 2011 rates adjusted by:

     - 0.88% by application of the Board's IRM Price Cap Index Adjustment formula;

- The establishment of a rate rider to recover 2013 incremental in-service capital of approximately $645 million per Hydro One’s proposed adjustments to the Board’s Incremental Capital Module (“ICM”) as outlined in Hydro One’s submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012;

- The disposition of the Group 1 Deferral and Variance accounts balance of $(37.5) million as at December 31, 2011 and the determination of a rate rider to refund those balances over two years as outlined in the Report of the Board on Electricity Distributor’s Deferral and Variance Account Review Initiative, EB – 2008-0046 dated July 31, 2009;

- The establishment of a rate rider associated with the 50%/50% sharing of the impact of decrease in income tax rate per the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors (EB-2007-0673) – September 17, 2008; also, pursuant to section 2.5 (Tax Changes) of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011;

- The establishment of a Smart Grid rate adder to recover Smart Grid OM&A spending of $19.8 million in 2013; and

- Approval to implement the final step of rate harmonization approved under EB-2007-0681.

- An adjustment to the retail transmission service rates as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 3.0 June 22, 2011) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012; and

- Approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision.

4. The written evidence filed with the Board may be amended, if necessary, at any time prior to the Board's final decision on the Application. Further, the Applicant may seek meetings with Board staff in an attempt to identify and reach agreements to settle issues arising out of this Application.

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

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

   a) The Applicant:

   Mr. Pasquale Catalano
   Regulatory Coordinator
   Hydro One Networks Inc.

Address for personal service: 8th Floor, South Tower
483 Bay Street
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b) The Applicant's counsel:

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Address for personal service: 100 Wellington Street West
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Toronto, ON M5K 1J5

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DATED at Toronto, Ontario, this 25th day of May 2012.

HYDRO ONE NETWORKS INC.
By its counsel,

ORIGINAL SIGNED BY DON H. ROGERS
Don H. Rogers

SUMMARY OF APPLICATION

Hydro One Networks ("Hydro One" or "Hydro One Distribution") is applying for an adjustments to rates and charges in accordance with directions provided by the Board pursuant to the 3rd Generation Incentive Rate Mechanism ("IRM3") effective on January 1, 2013 under the assigned Docket Number EB-2012-0136. Hydro One Distribution's rates were last rebased for the 2011 test year as per the Board's Decision in EB-2009-0096. This summary provides a brief description of the approvals being sought through this Application and a summary of reasons for the requested adjustments in customer rates.

1.0 SCOPE OF APPLICATION

The scope of this Application includes:

- the review of Hydro One Distribution's evidence in support of the revised Distribution rates effective January 1, 2013;
- an adjustment to the Retail Transmission Service Rates ("RTSR") as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 3.0 June 22, 2011) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012; and
- the request for approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision.

This submission reflects Hydro One Distribution's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability; system growth requirements and investments required to facilitate renewable generation connections.

This Application by Hydro One Distribution is substantially consistent with the requirements of the 2006 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on May 11, 2005 and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the Board on November 14, 2006 and updated Chapter 3 issued by the Board on June 22, 2011.

Hydro One is requesting the use of the 2013 Board Approved Cost of Capital parameters in the calculation of revenue requirement associated with the Incremental Capital Module. For rates effective January 1, 2013, the Board would determine the return on equity ("ROE") and other Cost of Capital parameters for Hydro One Distribution based on the September 2012 Consensus Forecasts and Bank of Canada data which would be available in October 2012. Further discussion on Cost of Capital can be found in Exhibit B, Tab 1, Schedule 2.

Hydro One also undertook a stakeholder consultation process to increase understanding of the issues in this Application and to provide a forum for early identification of stakeholder concerns, as documented in Exhibit A, Tab 4, Schedule 1.

2.0 APPROVALS REQUESTED

2.1 Distribution Rates

The Company is seeking approvals for Distribution rates effective January 1, 2013 based on Board approved 2011 rates adjusted by:

1. The OEB's 2012 IRM3 Rate Generator Model calculated a Price Cap Index increase of 0.88% for Hydro One Distribution based on a Price Escalator ("GDP-IPI") of 2.0%, minus a Productivity Factor of 0.72% minus a Stretch Factor of 0.40%. The price escalator (or inflation index) of 2%, for the 3rd Generation Incentive Regulation

mechanisms for adjusting electricity distribution rates effective May 1, 2012, was announced by the Board on March 13, 2012. Hydro One understands that the Price Escalator will be adjusted for those distributors whose rate year has been aligned with their fiscal year. Similarly, Hydro One recognizes that the Stretch Factor of 0.40% represents the 2011 amount as determined in the report "Third Generation Incentive Regulation Stretch Factor Updates for 2011 (EB-2009-0392)" issued by the OEB. Hydro One expects that the OEB will update each distributor's 2013 IRM3 Rate Generator Model and therefore the distributor specific Price Cap Index for the 2013 stretch factor. It is expected that the information to update the stretch factors will be available before the implementation date of the 2013 Tariff of Rates and Charges;

2. The establishment of a rate rider to recover 2013 incremental in-service capital of approximately $645 million per Hydro One's proposed adjustments to the Board's Incremental Capital Module ("ICM") consistent with Hydro One's submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012. The detailed description on the Incremental Capital Module can be found in Exhibit B of this application and the calculations of the revenue requirement for the requested ICM recovery can be found in Exhibit B, Tab 1, Schedule 2. Hydro One Distribution proposes to recover this amount by means of a variable rate rider, as outlined in Exhibit E1, Tab 2, Schedule 1, which will remain in effect until Hydro One Distribution's next cost of service application;

3. The establishment of a Smart Grid rate adder to recover Smart Grid OM&A spending of $19.8 million in 2013 as discussed in Exhibit C1, Tab 1, Schedule 1. Hydro One Distribution proposes to recover this amount by means of a variable rate rider which will remain in effect until Hydro One Distribution's next cost of service application. The calculation of Smart Grid Rate Riders by rate class can be found in Exhibit E1, Tab 2, Schedule 1;

4. The establishment of a rate rider associated with the 50%/50% sharing of $1.7 million as a result of the decrease in income tax rate from 28.25% to 25.5%, in accordance with the Board's requirement set out in the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) dated September 17, 2008; also, pursuant to section 2.5 (Tax Changes) of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011. The calculation of Shared Tax Savings Rate Riders by rate class can be found in Exhibit E1, Tab 2, Schedule 1;

5. The disposition of the Group 1 Deferral and Variance audited accounts balance of $(37.5) million as at December 31, 2011. This amount results in a total credit claim of $0.00104 per kWh, which exceeds the disposition threshold established by the Board in the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative, EB-2008-0046 dated July 31, 2009. Hydro One Distribution is proposing to dispose this credit amount over a two-year period in order to mitigate rate volatility. Details on Group 1 Deferral and Variance accounts disposition can be found in Exhibit E, Tab 2, Schedule 1 and the continuity schedules of these accounts can be found in Exhibit E, Tab 2, Schedule 1, Attachment 4; and

6. Hydro One Distribution is not applying for a Z-factor Claim in this application, however, Hydro One is undertaking a pension valuation and may consider applying for a Z-factor Claim in the future, depending on the results of the valuation.

2.2 Other Approvals

1. Hydro One also requests the Board approve the implementation of the final step of rate harmonization approved under EB-2007-0681. Details can be found in Exhibit E1, Tab 1, Schedule 1 of this application;

2. Hydro One is also making an adjustment to the RTSR as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 3.0 June 22, 2011) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012. The proposed RTSR charges for each rate class can be found in Exhibit C, Tab 2, Schedule 1; and

3. Hydro One seeks the Board's approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision. The results of the Density Study are discussed in detail in Exhibit D, Tab 1, Schedule 1 and attachments.

3.0 CONCLUSION

If the proposed adjustments are approved by the Board, distribution rates for a residential customer with an annual consumption of 800 kWh will rise by approximately 2.9% or 1.0% on a total bill basis in 2013. Including previously Board approved RTSR adjustments for 2011 and 2012, the total bill impact would be approximately 2.1%.

STAKEHOLDER CONSULTATION

1.0 OVERVIEW

This Exhibit reports on the stakeholder consultation process in support of the 2013 Distribution IRM Rate Application and provides a summary of the discussions held during five interactive consultation sessions. Hydro One Distribution's experience has been that early involvement with stakeholders is critical to developing a submission that reflects the broad interests and concerns of the Ontario Energy Board ("OEB") and Hydro One Distribution's constituencies.

Hydro One Distribution sought stakeholder input for three key areas of this Application including: the Board directed study and analysis of density and cost allocation relationships and its filing in this current application, details and schedule for replacing Hydro One's Customer Information System ("CIS") and Hydro One's plans for an ICM module as part of the 2013 IRM Application.

To assist in developing, implementing and facilitating this process, Hydro One Networks retained several expert consultants. The stakeholder consultation sessions were held beginning in September 2010 through to June 2012.

The overall goal was to improve the quality and comprehensiveness of the pre-filed evidence and to minimize the issues to be addressed at the OEB hearing. The consultation program consisted of presentations of information to stakeholders followed by discussion sessions on the issues raised. The presented information and notes of meeting were also made available through Hydro One Networks' website for those stakeholders that could not attend the sessions. In addition, Hydro One staff were available for informal dialogue with stakeholders throughout the process.

Input received during the consultation sessions was documented and considered in finalizing the application. Examples of this input include: (i) valuable feedback for the density study included focusing the study on first establishing the relationship between density and cost, and then relating that understanding to what it says about customer classes, and (ii) additional information stakeholders would like to see filed in support of the CIS replacement program and (iii) the preferred option for reflecting the density study findings in the IRM application.

Overall, Hydro One believes the stakeholder consultation process was effective in achieving many of its objectives as listed in Section 2.2.

2.0 CONSULTATION PRINCIPLES, DESIGN AND PROCESS

The following principles and objectives guided the consultation design and implementation.

2.1 Principles

- Hydro One is entering into the stakeholder consultation process in good faith with a view to facilitating and streamlining future OEB proceedings related to the application;
- Hydro One will receive and consider all submissions made by stakeholders, but will retain control over the process of developing its application;
- All consultations are carried out on a without-prejudice basis;
- An independent facilitator will document and report the discussions and any agreements reached with all or some stakeholders; and,
- Agreements reached will be submitted to the OEB as part of its evidence.

The goal for the stakeholder sessions was to create a forum for stakeholders and Hydro One to discuss issues related to the Hydro One Distribution Rate Application and to identify areas of agreement and concern to shape the pre-filed evidence. To further this mandate, participants were asked to:

- Represent the various views of their customers/constituencies; and,
- Assist Hydro One to understand their goals and issues through participation in a process of open dialogue and submissions.

2.2 Objectives

The objectives for stakeholder consultation included:

- Inform and update key stakeholders about Hydro One's Distribution business, and the approaches and methodology used to determine funding requirements, rider requests and rate adjustments;
- Give stakeholders a range of opportunities to provide input and feedback on all aspects of the application;
- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application;
- Act as a forum for the exchange of information and views;
- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences; and,
- Clarify and scope as many issues as possible prior to the Hydro One submission to the OEB.

2.3 Participants in the Consultation Process

Stakeholder groups including intervenors from previous Hydro One rate proceedings, OEB staff, LDCs and large distribution customers were invited to participate in the stakeholder sessions via an invitation letter by e-mail. Approximately, forty groups were invited to participate in the stakeholder sessions in person or via teleconference. Hydro One believes that those invited were representative of the interests of the majority of its stakeholders.

Those who were not able to attend were invited to monitor the process through the company's website and to provide input throughout the process.

Stakeholder participation was guided by a Terms of Reference and funding was made available to eligible intervenors consistent with the current OEB's Practice Direction on Cost Awards.

2.4 Website

As part of the consultation process, Hydro One created a 2013 Distribution Rate Application web page. The intent was to provide interested stakeholders the opportunity to monitor the consultation process and to provide input throughout the consultation.

The 2013 Distribution Rate Application web page http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx was updated regularly and contained meeting agendas, presentations made available at the stakeholder sessions and the meeting notes. Hydro One Distribution stakeholders were advised by email about the sessions, agendas, and how they could participate or follow the proceedings via the regulatory website if they could not attend.

2.5 Consultation Process Design

Five consultation sessions were held in beginning in September 2010 through to June 2012:

- September 8, 2010—Density and Cost Allocation Study, Metropolitan Hotel, Toronto
- March 22, 2011—CDM Study and Density and Cost Allocation Study, Hydro One Head Office, Toronto
- June 29, 2011- CIS Replacement Project, Metropolitan Hotel, Toronto
- October 19, 2011— CDM, Density Cost Allocation, CIS Replacement Project Update, Hydro One Head Office, Toronto
- June 5, 2012 – 2013 Distribution IRM Application and Density and Cost Allocation Study

Sessions involved presentations on the pertinent topic followed by a facilitated discussion, which provided stakeholders an opportunity to ask questions and to comment on the presentations and proposed approach to the studies and content of the Application.

3.0 CONSULTATIONS

3.1 Density and Cost Allocation Study

In its Decision for EB-2009-0096, the Board directed Hydro One to comply with its prior direction to complete a study on the issue of density, cost allocation and rate class structure noting that “The Board expects Hydro One to work cooperatively with the parties but leaves it to Hydro One’s discretion to determine how best to conduct the study taking into consideration timing, feasibility and cost”.

Four consultation sessions were devoted to discussing and obtaining stakeholder input on the density and cost allocation study.

The first session, held September 8, 2010, had 11 stakeholder attendees representing 10 stakeholders and OEB staff.

John Todd (President, Elenchus Research Associates) provided a brief review of the expert evidence with respect to density-based rates that Elenchus and Dr. Woo (on behalf of the School Energy Coalition) provided to the OEB in 2009 (EB-2009-0096). John's presentation covered the conclusions of the two sets of evidence, their similarities and differences, the issues that remain to be resolved, and suggestions with respect to how outstanding issues might be dealt with. The ensuing discussion focused on questions of clarification related to John's presentation, and general questions relevant to his expertise.

Henry Andre (Manager, Pricing) provided further detail and history with respect to the OEB's past directives regarding the Distribution Density Study, presented an overview of Hydro One's existing density based rate classes and density weighting factors, and outlined next steps and potential elements of the scope of the study for discussion with stakeholders.

The Meeting Notes of this session are found in Appendix A.

The second session, held March 22, 2011, had 17 stakeholder attendees representing 16 stakeholders and OEB staff. The two general objectives for the stakeholder session were to reach a general agreement on the proposed methodology and to receive specific feedback from stakeholders. A joint presentation to stakeholders was given by London

Economics International LLC and PowerNex Associates, Inc. The presentation generated stakeholder feedback and discussion throughout.

The Meeting Notes of this session are found in Appendix B.

The third meeting regarding the density cost allocation study was held October 19, 2011. Eighteen attendees representing 16 stakeholders and OEB staff attended the session. Results of the Density study were presented by Benjamin Grunfeld on behalf of London Economics International and PowerNex Associates Inc. The econometric analysis undertaken indicates a negative or inverse relationship between cost and customer density. Four distinct models were analyzed and all showed a negative relationship. Two independent analyses confirm that the average cost to serve Hydro One customers increases as the customer density decreases with 99% statistical confidence. Further details of the results can be found in the meetings notes of the session in Appendix D.

The fourth meeting respecting the density cost allocation study was held June 5, 2012. Sixteen attendees representing 12 stakeholders and OEB staff attended the session. Results of the Density study were summarized and Hydro One’s implementation plan for the study results were presented by Henry Andre, Hydro One’s Manager, Pricing, including the immediate need to adjust the cost allocation between residential rate classes. Henry presenteds two options for stakeholder consideration. It was agreed that both options would be included in the prefiled evidence and Hydro One’s recommendation would reflect stakeholder feedback.

Further details of the results can be found in the meetings notes of the session in Appendix E.

3.2 Customer Information System Replacement

On June 29, 2011, Hydro One held a stakeholder session on the development and replacement of Hydro One's Customer Information System. Twelve attendees representing 11 stakeholders and OEB staff attended the session. At the session, Hydro One informed stakeholders of the project plan and cost of the the replacement CIS project which is Phase 4 of the Conerstone initiative. The anticipated benefits were also reviewed. Hydro One presenters included Mike Winters, Vice President, Information Technology, Myles D'Arcey, Senior Vice President, Customer Operations and Jeff Smith, Director, Project Management and Control. The existing Customer 1 system was developed in 1998 and is no longer supported by the vendor. The new CIS SAP system is widely used worldwide and allows for easier integration with current systems.

Stakeholders requested the cost-benefit analysis provided to Hydro One's Board of Directors and the template used by Enbridge Gas Distribution Inc. be included in the filing and Hydro One agreed to do so.

The Meeting Notes of this session are found in Appendix C.

On October 19, 2011, Hydro One held a stakeholder session which included an update on the progress of the the Cornerstone Phase 4 CIS intitiative. Brad Bowness, Hydro One's Director, Business Architecture provided an update on the status of the CIS project. Further details of the presentation can be found in the meetings notes of the session in Appendix D.

3.3 Overview of 2013 IRM Application

At the June 5, 2012 Stakeholder Session, Allan Cowan, Director Major Applications provided an overview of Hydro One's 2013 Distribution IRM Application indicating the supporting evidence would be filed in mid-June once stakeholder input has been received at the session today. Allan indicated the application would include; a Price Cap Index adjustment of 0.88%; an ICM to recover total in-service capital additions; a rider to recover 2013 Smart Grid OM&A expenditures; a Tax Sharing Credit Refund and the disposition of the Group 1 Deferral and Variance accounts.

Allan also indicated Hydro One would be seeking adjustment to Retail Transmission Service Rates, approval to implement the final phase of the rate harmonization process and approval to implement the results of the Board directed Density Study.

Susan Frank, Vice President and Chief Regulatory Officer and Ian Malpass, Director, Regulatory Pricing and Support provided stakeholders with an overview of Hydro One's proposed ICM module and reviewed the current concerns with the current OEB ICM model. Hydro One's proposed ICM follows the approach outlined by Hydro One in its submission to the Board in the Renewed Regulatory Framework for Electricity consultation process. Ian indicated that based on the existing OEB Threshold Test, Hydro One was eligible to file for an ICM.

Further details of the presentations can be found in the meetings notes of the session in Appendix E.

4.0 STAKEHOLDER CONSULTATION SUMMARY

Hydro One initiated the stakeholder consultation process to meet the objectives described in Section 2.2. Based on the discussions that took place, the consultation process met these objectives. Hydro One believes that the enhanced understanding by stakeholders of Hydro One operations and business practices resulting from the dialogue at these sessions should reduce the effort required by Hydro One to explain its rate application during the OEB proceeding. Hydro One also obtained a good understanding of stakeholder issues and concerns through the consultation process.

In conclusion, stakeholder input helped Hydro One to refine and shape the elements of its Distribution IRM rate application and helped to ensure that customer and stakeholder concerns were understood and addressed.

5.0 LIST OF APPENDICES

A. Meeting Notes: Stakeholder Discussion Sessions – September 8, 2010
B. Meeting Notes: Stakeholder Discussion Session – March 22, 2011
C. Meeting Notes: Stakeholder Discussion Session – June 29, 2011
D. Meeting Notes: Stakeholder Discussion Sessions – October 19, 2011
E. Meeting Notes: Stakeholder Discussion Session – June 5, 2012

Stakeholder Consultation
2012/2013 Distribution Rate Application

September 8, 2010 Stakeholder Session

Responding to the OEB Directive on the Study of the Relationship Between Density and Cost Allocation

Meeting Notes

Metropolitan Hotel
108 Chestnut Street, Toronto
Victoria Room

Prepared for:
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Prepared by:
Haussmann Consulting Inc.
435 Roehampton Ave.
Toronto, Ontario
M4P 1S3

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1. Agenda Package and Participant List
2. Discussion Questions and Answers
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4. Cost Allocation Methodology

1. BACKGROUND

Hydro One Networks Inc. is in the process of preparing its 2012/13 Distribution Rate Application for submission to the Ontario Energy Board (OEB) during the autumn of 2011 for rates effective January 1, 2012 and January 1, 2013.

In its Decision with Reasons on Hydro One Network's 2008 Distribution Rates Application the Ontario Energy Board (OEB) directed Hydro One to provide a study on the relationship between density and cost allocation (EB-2007-0681, pg. 30-31).

Hydro One has three different residential year-round customer classes and two General Service customer classes reflecting different density definitions. The current density definitions approved by the OEB are Urban (U), Medium Density (R1) and Low Density (R2). Urban density is defined as areas containing more than 3,000 customers with line density higher than 60 customers per kilometre. Medium density is defined as areas with at least 100 customers with line density higher than 15 customers per kilometre. All other customers are Low density. These density definitions were established by Ontario Hydro and have been in use for many years.

The Cost Allocation methodology used by Hydro One to apportion distribution line and transformer assets and costs to customer classes uses weighting factors as a means to reflect the differences in costs of serving its density-based rate classes. The weighting factors were developed by Hydro One based on feeder specific data and were used in Hydro One's Cost of Service application in proceedings EB-2007-0681 and EB-2009-0096.

A Phase 1 report prepared by John Todd of Elenchus Research was included in Hydro One Network's 2010/2011 Distribution Rates Application (EB-2009-0096). The Phase 1 report (which was presented to and discussed with stakeholders at a consultation session on May 25, 2009) outlined the principles and possible alternatives that could be considered to address the OEB directive. In its Decision on EB-2009-0096, at page 66-67, the OEB directed Hydro One to complete a study of the relationship between density and cost allocation (the "Study"). The OEB chose not to specify the precise methodology or approach to use, leaving it to Hydro One's discretion to determine how best to conduct the study taking into consideration timing, feasibility and cost. The results of this study are to be presented at Hydro One's next cost of service application.

Hydro One invited key stakeholders who have participated in previous Hydro One Networks rate proceedings to participate in a consultation session to provide input regarding the approach, methodology, scope and Terms of Reference (ToR) for the required study. Proposed discussion questions and a high-level outline of a density and cost allocation study ToR were emailed to stakeholders prior to the session. This document reports on the stakeholder consultation that took place on September 8, 2010.

1.1 Welcome and Agenda

Ian Malpass (Director, Major Applications, Hydro One Networks) welcomed participants and provided an overview of the day's agenda. He thanked participants for their attendance and encouraged them to provide their ideas and perspectives regarding the methodology, scope and ToR for the density/cost allocation study that the OEB has directed Hydro One to complete, noting the importance of their input to how Hydro One addresses the OEB's directive and the specific approach taken to the study.

1.2 Introductions

Chris Haussmann of Haussmann Consulting Inc. (HCI) introduced himself as facilitator for the workshop. He then asked participants to introduce themselves. In attendance were representatives from the Association of Major Power Consumers of Ontario, Canadian Manufacturers and Exporters, Energy Probe, EnviroCentre, Federation of Ontario Cottagers' Associations, Ontario Energy Board, Ontario Federation of Agriculture, Powerstream, and Vulnerable Energy Consumers Coalition. Also present were Hydro One staff, John Todd, President of Elenchus Research (for only the first part of the session), and the HCI facilitation team.

The full list of participants, together with the agenda, is provided in Attachment #1. Attachment #2 presents the more detailed questions and answers raised in the discussions that followed each of the presentations.

2. PRESENTATIONS AND DISCUSSION

The following sections provide brief descriptions of the presentations made by Hydro One staff. Questions of clarification and discussion following each presentation are summarized in bullet form. Points in *italics* represent responses or comments from Hydro One. All meeting presentation slides are available on the Hydro One Regulatory Web site at:
http://www.hydroonenetworks.com/en/regulatory/

2.1 Review of 2009 Density and Cost Allocation Evidence

John Todd (President, Elenchus Research Associates) provided a brief review of the expert evidence with respect to density-based rates that Elenchus and Dr. Woo (on behalf of the School Energy Coalition) provided to the OEB in 2009 (EB-2009-0096). John's presentation covered the conclusions of the two sets of evidence, their similarities and differences, the issues that remain to be resolved, and suggestions with respect to how outstanding issues might be dealt with.

The Elenchus evidence concluded (Slide 3) that:

- rate making principles provide little support for separate urban and rural classes based on customer or demand densities that affect causal costs;
- density-based definitions of urban and rural customer classes are more or less unique to Hydro One, with most utilities using municipal boundaries to define these classes; and,
- costs could be allocated to urban and rural customer classes using either sample data or engineering analysis.

John then outlined the conclusions (Slide 4) that flowed from Dr. Woo's expert evidence to the OEB:

- Hydro One Distribution's density-based rates are not adequately supported by a reasonably done cost allocation analysis and should be simplified to urban/rural rates;
- urban/rural cost allocation can be developed from available information, using a seven step process; and,
- the econometric model in Lowry, Getachew and Fenrick should be used to compute the log of total OM&A expenses for urban and rural areas.

John noted the similarities and differences in his and Dr. Woo's expert evidence to the OEB (Slide 5). Both sets of evidence suggest that density-based classes should be replaced with urban and rural classes based on (or linked to) municipal boundary definitions. Elenchus identifies the use of either sample data or engineering analysis as the most practical and cost effective way to allocate costs to urban and rural classes, while Dr. Woo's evidence proposes econometric analysis to define area-specific cost drivers. It is noteworthy that all three proposed cost allocation options are estimation techniques that estimate the cost *differences* between classes (however they are defined) that will then be used as the allocator, rather than a true cost allocation model in which drivers are used to allocate costs to classes.

All of the options for estimating urban and rural costs are imperfect and give rise to certain issues (Slide 6). Using the sample data approach would reflect actual Hydro One costs, but the results will vary with how representative the chosen urban and rural samples are of Hydro One's territory. The engineering method would generate actual urban and rural characteristics, but would reflect future costs, not embedded costs. In general, and in Ontario, cost allocation models are based on embedded costs. To do an engineering study that reflects what is embedded in Hydro One's system today could be very difficult and expensive. The econometric approach would be based on industry data, not Hydro One data, and therefore may not accurately reflect Hydro One's system characteristics. Furthermore, Dr. Woo's proposed econometric method is based on OM&A costs and excludes capital costs, although there may be ways to include capital costs in the analysis.

Based on the expert evidence provided to the OEB by Elenchus and Dr. Woo, John concluded his presentation by making the following suggestions for consideration, as appropriate, by stakeholders and Hydro One with respect to the study (Slide 7):

- Adopt urban and rural definitions consistent with standard practice (linked to Ontario municipal boundaries in an appropriate way);
- Address the details of the class definitions to determine whether it is practical to use municipal boundaries;

- Identify and assess alternate methods of determining urban and rural class costs
- Ensure chosen method is cost effective; and,
- If estimation method is used (rather than direct cost allocation), multiple estimation methods should not be ruled out.

The ensuing discussion focused on questions of clarification related to John's presentation, and general questions relevant to his expertise. John left the meeting following his presentation and related discussion. He did not participate in the discussion of the density/cost allocation ToR.

Discussion

The following summarizes the main points raised in the lively discussion that accompanied John Todd's presentation.

- It was noted that using municipal boundaries as delineators of urban and rural customer classes is problematic in Ontario. Due to numerous amalgamations, including the Harris government's province-wide reconfiguration of municipal boundaries, many municipalities contain a variety of urban population centres as well as rural areas with rural densities. Also, some municipalities are served in their historic urban centres by a local distribution company and by Hydro One in the remaining, more rural or new urban areas. While this traditional and widely applied means of delineating urban and rural customer classes may not be ideal or even applicable in Ontario, it does have the advantage of being an independent definition of the customer class. The definition of urban and rural classes should be based on a practical and objective definition of the customer classes.

- Concern was expressed that the discussion was focusing on the urban versus rural customer class definition. While it may be difficult to avoid the urban/rural paradigm when considering density, the OEB direction was to look at the relationship between density and cost allocation, not the definition of urban and rural customer classes. It was suggested that the study should focus first on the cost drivers that relate to density. Neither the current system, nor municipal boundaries, nor the number of customers per kilometre may be the correct cost drivers. The OEB did not ask Hydro One to go to the next step and define new customer classes. But people would like an examination of whether the current density-based customer class definition makes any sense from a cost allocation fairness perspective.

- The methodology that may be used to determine cost drivers was discussed at length. It was noted that:
    - The econometric model approach is technically feasible, but challenging in that the data base used should incorporate both OM&A and Capital expenses. There is great variability in cost drivers among Ontario utilities and it would be difficult to construct a model that incorporates them all. Missing one or more of the variables may result in an inaccurate coefficient for the density related cost drivers.

    - It may be wise to apply more than one method or model to the problem in order to increase the accuracy of the outcome.

- Neither the Elenchus nor the Woo study commented on the distinction between R1 and R2 rural rates. The intent is to characterize the cost drivers related to density. The findings may or may not reveal natural density-related customer class delineations, but these are not pre-determined. Of course, any variance of the R1 and R2 distinction would also affect the Rural and Remote Rate Protection (RRRP), which applies only to the R2 customer class.

- It may be helpful at the outset of the study to ask the question whether it is even possible to reach rigorous conclusions within a reasonable time period and at reasonable cost.

- It was suggested that the study might look at how cost allocation relates to density in other industries (e.g. telecommunications) and in other countries (e.g. Eastern Europe). The telecommunications industry has a very different business model (value for service) than the electricity industry (cost of service), and European countries operate under a very different regulatory regime, making comparisons difficult and complex.

- When asked, no one suggested that Dr. Woo's submissions were not accurately represented in the discussion. One participant expressed the view that Dr. Woo's position was indeed fairly represented, and no one disagreed with that view.

2.2 Distribution Density Study: Background and Scope of Study

Henry Andre (Manager, Major Applications) provided further detail and history with respect to the OEB's past directives regarding the Distribution Density Study, presented an overview of Hydro One's existing density based rate classes and density weighting factors, and outlined next steps and potential elements of the scope of the study for discussion with stakeholders.

During the 2008 Distribution Rate Application (Slide 2), a number of interveners raised concerns as to whether the density weighting factors Hydro One uses in its cost allocation process accurately reflect the costs that are attributable to those rate classes and whether the weighting factors should also be applied to other rate classes. In response, the OEB's Decision with Reasons (EB-2007-0681, pgs. 30-31) addressed these issues by directing Hydro One to:

- provide a more detailed analysis of the relationship between density and cost allocation;
- consider whether the number of Residential and General Service classes is adequate and whether the approved customer class demarcations offer the best reflection of cost causation;
- include consideration of alternative density weightings; and,
- provide comparisons with the costs of distributors similar in size and location to Acquired Distributors.

Hydro One addressed the density/cost allocation issue in its 2010/2011 Distribution Application with the Phase 1 report by Elenchus Research (Slide 3). The OEB also heard the School Energy Coalition's intervenor evidence. In response, the OEB's Decision with Reasons (EB-2009-0096, pgs. 66-67): reiterated its prior direction; indicated that it would not specify the precise methodology or approach Hydro One should use; and, asked Hydro One to work cooperatively with the parties while leaving it to Hydro One's discretion to determine how best to conduct the study, taking into account timing, feasibility, cost and project efficiency.

The current Hydro One Residential rate classes (Slide 4) that are density-based include the Urban, R1 (High Density) and R2 (Normal Density). General Service customers are also split by density and include Urban General Service Energy (UGSe – small commercial), Urban General Service Demand (UGSd – greater than 60 kW), General Service Energy (GSe), and General Service Demand (GSd). Residential and General Service customers within a cluster of more than 3,000 customers and with a line density of more than 60 customers/kilometre fall into the urban rate class.

Hydro One uses density weighting factors to allocate Overhead Lines and Transformers costs (Slide 5) that take into account both fixed costs (number of customers/line or Net Book Value (NBV) of transformer assets by class for each feeder) and variable costs (energy by customer class by feeder). The current methodology attempts to allocate costs across rate classes (Slide 6) by taking into account an admittedly limited number of factors (number of customers, length of feeders, energy consumed, NBV of transformers).

Henry indicated (Slide 7) that Hydro One fully intends to complete the Density Study as directed by the OEB, but that it is struggling with what the study should look like. It is therefore seeking input from stakeholders at this session on the scope of the study in order to help shape a Request for Proposal (RFP) and engage a suitable consultant before the end of the year. Following this consultation process, Hydro One intends to communicate to the OEB what it has heard from stakeholders and the approach it intends to follow to ensure that the OEB is satisfied that the proposed approach will fully address the OEB's Direction.

Henry then provided for discussion the potential elements of a draft scope of study and a proposed timeline (Slides 8-10). In order to address the OEB's directive to assess the relationship between density and cost allocation, the most challenging and key component of the scope will be to develop options for the "density" definitions (variation of status quo, feeders, municipal or regional boundaries, etc.) that will be evaluated by the study. Subsequent elements of the study (determine data to be collected, develop data collection methodologies, data gathering and analysis, rate class/weighting alternatives, cost allocation model results and impacts on customer bills) will be driven by the choice of definition options. Hydro One expects that an RFP can be issued and contract awarded to do the study by December 2010, with a final report available in August 2011, and submitted as part of the pre-filed evidence for the next cost of service application.

Discussion

Stakeholders asked questions throughout Henry's presentation. The following summarizes the points raised during that dialogue. The complete exchange can be found in Appendix 2.

- Two points of clarification arose at the outset:
  - It was explained that, currently, a density weighting factor of "1" is applied to four rate classes: Dgen, ST, StLgt and SenLgt, because these rate classes are not deemed to be density driven.
  - Also, a distinction is made between R1 and R2 to distinguish those customers (R2) who qualify for the RRRP subsidy. Some GSe and GSd farm customers do receive the RRRP subsidy. These will all be moved to R2 once rate harmonization is completed by the end of 2011. So all customers receiving RRRP will be in the R2 class at that time.

- There was extensive discussion about the order of tasks in the study. It was considered important to avoid bias in favour of the current classification by starting with definitions of density options before mining the data to ascertain whether there were logical breaks in the density/cost relationship that then indicated where the customer class breaks should be. By gathering as much data as possible on cost drivers and doing relatively "unstructured" analysis, Hydro One may find that the data shows there are drivers more important than density.

- It was suggested that Hydro One first should establish the relationship between density and cost. Once that is established, Hydro One should determine what data it can readily collect to quantify these density related cost drivers and how they relate to customer classes. The rate implications of the density definitions that result from this analysis could then be calculated.

- This raised the question of what data should be collected. A starting point would be the data Hydro One currently uses to determine density related cost allocation (customers and MWH per kilometre). Other suggestions included:
  - Differential analysis of service depot data (from some 40 service depots) such as travel distance to service calls, weather, forestry costs, planned/unplanned outages, and including customer density could provide a reasonable indicator of the real cost drivers fairly quickly and at limited cost;
  - Capital costs;
  - Asset age;
  - Future cost trends (e.g. forestry, Green Energy Plan programs such as Micro-Fit);

- It was also noted that the data collected should be relevant to cost allocation. The practicality and benefit/cost of data gathering and analysis should be key watchwords keeping in mind the impact on customers. It could turn out that density reviews may become a regular requirement in rate making.

- A great deal of data is already available through the OEB. Suggested data sources included:
  - PEG (Pacific Economics Group) report to the OEB;
  - The triple Rs (Reporting and Record Keeping Requirements) from the OEB year book
  - OM&A data; and,
  - Assessment of costs across the LDCs in Ontario.

- Other possible starting points mentioned were to:
  - Validate (or disprove) the current density-based class definitions using Hydro One sample data; and,
  - Identify an independent LDC with characteristics similar to an acquired LDC and compare their respective costs of service (this would require Hydro One to draw a sample from the acquired LDC area that has now been integrated into the Hydro One system).

- Provincial policy trends (e.g. no distance-based rates) also need to be respected.

- One participant felt that the study should also consider the experience of other jurisdictions beyond North America because operating under a different regulatory regime may in fact reveal density-related cost factors more clearly.

2.3 Prepared Questions Discussion

In preparation for the session, stakeholders received an agenda package that included a summary overview of the Terms of Reference and the six questions below to consider for discussion. The facilitator turned people's attention to these questions after the presentations and related discussion.

1. a) Is now the right time to study rate classification/density (in light of pending TOU rates, Smart Meters, rate increases, etc.)?

   b) How much tolerance is there for rate changes at this time?

2. Is density an appropriate factor to define rate classes?

3. Are there factors other than density that distinguish urban versus rural rate classes?

4. Is there value to more precisely determining the costs applicable to existing density-based residential classes?

5. What are the cost factors applicable to urban and rural rate classes?

6. How precisely should the data collected in the study reflect actual cost of service, and how should these best be determined (e.g., using sample data from Hydro One, using benchmark data from a variety of LDCs, engineering analysis, connectivity analysis)?

Discussion

Question 1

Hydro One expressed concern that a considerable amount of money and human resources could be devoted to this study when there was currently no appetite for making changes to customer classes or cost allocation that would result in rate changes creating winners and losers, especially in light of the many other changes still working their way through the system (e.g. rate harmonization, Green Energy Plan, Time of Use rates etc.). Hydro One sought assurances from intervenors that they would be receptive to cost allocation or customer class definitions if the study recommended this.

Intervenors responded that the OEB had ordered a study of the relationship between density and cost allocation without making any pre-judgments about carrying through with changes to rates or customer classes. In the first instance, intervenors support conducting the study to determine whether the current density-related cost allocation model is fair or not, and whether there are other, more valid cost drivers that should be reflected in the cost allocation model. In the absence of knowing the study findings, they could not commit to supporting changes to the cost allocation model or customer class definitions. However, it was noted that should the findings conclude that such changes are warranted, the OEB does have mechanisms for implementing change gradually without creating rate shock among ratepayers.

In relation to this question, the matter of cost of the study was also discussed. What would be a reasonable resource allocation given the uncertainty of concrete follow-through changes in cost allocation? Cost estimates provided ranged from $250,000 to $1.5M, depending on the study methodology used and the degree of data granularity collected. Intervenors were unable to provide a quantitative guideline as to what would be a reasonable cost, but stated that the cost allocation should be sufficient to provide useful information. In this regard, it was suggested that there were numerous sources of data readily available (see discussion in Section 2.2), and that the application of several methodological approaches to data analysis could help to produce a useful result with some confidence and at reasonable cost (see also discussion in Section 2.1).

It should be expected that the study will reveal the extent to which there exist cross-subsidies among customer classes. Depending on the extent of such subsidies, there may be more or less appetite for changing the cost allocation and customer class definitions.

Questions 2-5

These four questions relate to the nature of the distribution cost drivers and their relationship to density. They were discussed to varying degrees interchangeably throughout the dialogue. The following summarizes the key points raised in the discussion.

- The study should address two fundamental questions:
    i. Assess whether density related cost drivers or some other cost drivers should be used to allocate costs; and,

ii. In light of the knowledge gained from (i), how should customer classes be defined to create the greatest degree of fairness (i.e. cost-based rates).

- The scope of the study should try to take into account historic use patterns as well as the likely effect of future trends to the extent possible (e.g. urbanization, distributed generation, smart grid, conservation, MicroFIT program, Time of Use demand shifts).

- Vegetation and storm management costs are clearly related to density insofar as they are much higher in low density as opposed to high density areas. On the other hand, there are also costs unique to high density areas, such as underground facilities.

- It is conceivable that factors such as asset age and average customer distance from service depots may be more influential cost drivers than density. Old acquired systems with moderately high density service areas may be more costly to serve than farms on upgraded feeders being served directly from a transformer station without a substation.

<u>Question 6</u>

Study methodologies were discussed in the context of John Todd's presentation (see Section 2.1), but some additional comments were also made or reiterated in this portion of the meeting.

- Differential analysis of service-depot based data could provide a relatively quick method to identify cost drivers.

- Relative to other factors, it is unlikely that the effect of the Green Energy Plan will be a significant cost driver. The Green Plan should not be used as a reason to delay the study.

- With respect to applying more than one methodology to provide greater confidence in the results, one suggestion was to supplement the Hydro One sampling methodology with engineering studies and simulations where sample data are questionable or difficult to obtain.

- Two tasks the study should accomplish are:
    - Test the current density definitions to see if they stand up to the analysis of cost drivers; and,
    - Assess the advantages and disadvantages of using municipal boundaries to delineate customer classes in Ontario.

- The question was raised, whether the study would look only at customer classes that currently have density-based rates, or all classes. The original intent was to study only density-based rate classes. However, following the suggested approach, all rate classes may be affected if new cost drivers identify different rate classes.

Follow-up Stakeholder Consultation

Suggestions were made to obtain additional input from stakeholders at two different points in the study process:

- Circulate draft Terms of Reference to stakeholders for comment before finalizing them;

- Meet with stakeholders to present and discuss preliminary study results.

3. CLOSING REMARKS/NEXT STEPS

Ian Malpass thanked stakeholders for their participation and input, and noted that their contributions will help Hydro One shape the ToR. Hydro One will consider the suggestion to circulate a draft ToR before issuing an RFP, and to meet again with stakeholders before finalizing the study report.

Chris Haussmann reminded participants to complete and submit the Consultation Evaluation Form before the end of the week. The meeting was adjourned at 12:30 pm.

4. MEETING EVALUATION

Appendix 3 presents a copy of the questionnaire stakeholder participants were asked to complete to evaluate the meeting, and the consolidated returns from the six forms that were received. The comments indicate that most participants agree or strongly agree that:

- The information presented was clear;
- Stakeholder participants had adequate opportunity to share their views with Hydro One;
- The consultation session met their expectations; and,
- Overall, the preparation package was thorough and included all relevant and essential information for the session.

Additional comments received indicate that:
- The topic is a difficult issue to address;
- The discussion was open and animated, although more time could have been useful;
- Some preconceptions created initial confusion and took time to clarify;
- Responsiveness of Hydro One to suggestions remains to be determined.
- One participant disapproved of the facilitation (no detail provided).

APPENDIX 1

AGENDA PACKAGE AND LIST OF PARTICIPANTS

Stakeholder Consultation
2012-2013 Distribution Rate Application

Responding to the OEB Directive on the Study of the Relationship Between Density and Cost Allocation

Agenda
September 8, 2010
Metropolitan Hotel, Victoria Room (2nd Floor)
108 Chestnut Street, Toronto
9:00 a.m. – 12:15 p.m.

8:30 a.m. Registration and Continental Breakfast served		
9:00 a.m.	Welcome	Ian Malpass, Director, Major Applications, Hydro One Networks
9:05 a.m.	Introductions and Agenda	Chris Haussmann, Facilitator, Haussmann Consulting Inc.
9:15 a.m.	Review of 2009 Density and Cost Allocation Evidence	John Todd, President, Elenchus Research Associates
10:15 a.m.	Background and OEB Directives	Henry Andre, Manager, Transmission and Distribution Pricing
10:30 a.m.	**BREAK**	
10:45 a.m.	Facilitated Discussion of Questions	Chris Haussmann
12:00 p.m.	Next Steps	Henry Andre
12:05 p.m.	Closing Remarks	Ian Malpass
12:15 p.m.	**Adjourn**	

Stakeholder Consultation
2012-2013 Distribution Rate Application

Responding to the OEB Directive on the Study of the Relationship Between Density and Cost Allocation
September 8, 2010

List of Confirmed Participants[1]

Name	Association
Hydro One	
Andre, Henry	Hydro One
Cancilla, Enza	Hydro One
Frank, Susan	Hydro One
Innis, Ian	Hydro One
Malpass, Ian	Hydro One
Wilson, Mark	Hydro One
Facilitator/Consultants	
Haussmann, Chris	Haussmann Consulting Inc.
Mueller, Peter	Haussmann Consulting Inc.
Todd, John	Elenchus Research Associates
Stakeholders	
Bradbury, Douglas	Canadian Niagara Power Company Ltd.
Clark, Wayne	Association of Major Power Consumers of Ontario
Cowan, Ted	Ontario Federation of Agriculture
Dade, Christine	Powerstream Inc.
DeRose, Vincent J.	Canadian Manufacturers and Exporters (CME)
Harper, Bill	Vulnerable Energy Consumers Coalition
MacIntosh, David (plus 1)	Energy Probe
McGee, John	Federation of Ontario Cottagers' Associations
Silk, Dana	EnviroCentre
Thiessen, Harold	Ontario Energy Board
Thompson, Peter	Canadian Manufacturers and Exporters (CME)

[1] Confirmed as of September 7, 2010

Discussion Questions for Density – Cost Allocation Consultation
September 8, 2010

1. a) Is now the right time to study rate classification/density (in light of pending TOU rates, Smart Meters, rate increases, etc.)?

   b) How much tolerance is there for rate changes at this time?

2. Is density an appropriate factor to define rate classes?

3. Are there factors other than density that distinguish urban versus rural rate classes?

4. Is there value to more precisely determining the costs applicable to existing density-based residential classes?

5. What are the cost factors applicable to urban and rural rate classes?

6. How precisely should the data collected in the study reflect actual cost of service, and how should these best be determined (e.g., using sample data from Hydro One, using benchmark data from a variety of LDCs, engineering analysis, connectivity analysis)?

September, 2010

DRAFT
Terms of Reference – Density Study

Introduction

Provide background material on the following:

- Evidence submitted on this issue in Hydro One Network's 2010/2011 Distribution Rates Application (EB-2009-0096).
- Decision with Reasons in EB-2009-0096.
- Decision with Reasons in Hydro One Network's 2008 Distribution Rates Application (EB-2007-0681).
- Existing density based rate classes and weighting factors used in Cost Allocation model

Scope of Work

Hydro One is seeking the services of an expert in the field of cost allocation and rate design to complete a Density Study. The consultant is required to complete the following items of work:

1. Develop options for the "density" definitions that will be evaluated as part of this study.
2. Develop methodology for collecting the data required to assess the relationship between costs and density for the various options.
3. Collect the necessary data.
4. Analyse data collected to develop rate class and weighting factor alternatives that will be put through the cost allocation model.
5. Evaluate cost allocation model results and assess the impact on customer's bills.
6. Prepare a final report documenting the work undertaken.

Schedule

Issue RFP and award contract: *by Dec 2010*
Develop study methodology and collect necessary data: *Jan to Apr 2011*
Analyze data and propose cost allocation model inputs: *May 2011*
Run cost allocation model, evaluate results and customer impacts: *Jun to Jul 2011*
Prepare final report: *Aug 2011*

APPENDIX 2

FACILITATED DISCUSSION
QUESTIONS AND ANSWERS

Answers are presented in italics

Review of 2009 Density and Cost Allocation Evidence Discussion

- There is a problem using municipal boundaries in Ontario (Slide 3) because of the uniqueness of the political boundaries. For example, in the City of Ottawa, Ottawa Hydro serves the high density customers, but the vast majority of the land mass of the city is served by Hydro One. The same is true in Hamilton, where Horizon serves Hamilton, Stoney Creek and Dundas, and the remaining two-thirds of the land mass is served by Hydro One. Most or many utilities in Ontario do not serve the entire customer base within their municipal boundaries.

  The standard is that the historical boundaries of towns and LDCs were in alignment. Through the Harris and other amalgamations, these alignments have changed. I am not suggesting using municipal boundaries is an automatic or simple thing. However, given that using municipal boundaries is the standard approach and for other reasons provided in the evidence to the OEB, using municipal definitions, perhaps with some modifications, should be considered to develop a practical basis for defining the territory that is urban and rural for Hydro One. This may not be simple to do, but as the evidence to the OEB noted, other alternatives are at least as difficult to apply. One of the challenges of the whole urban-rural concept is coming up with appropriate definitions, and it is easy to get into an impossible morass around, for example, the level of granularity. So regardless of who does the study, you may want the ToR to reflect that you want a simple, practical and independent way to define urban and rural classes based on municipal boundaries.

- I agree that using municipal boundaries is a problem. I work in Ottawa/Eastern Ontario and deal with people all the time that say that the City of Ottawa is half the size of Prince Edward Island, so the urban-rural approach certainly won't work in the City of Ottawa. I am a bit concerned that the direction of the OEB to look at density and cost allocation seems to be morphing into urban and rural. There are many highly densely populated areas within rural areas. So you can't simplify things down to urban and rural classes. I'd like to get back to density. In addition, people living in urban versus rural areas are not similar. They have very distinct demographic and other characteristics.

  There is a wide variety of customers within all classes. One of the issues in defining rate classes is the extent to which different classes overlap in terms of their variety, rather than being distinct. The more overlap there is, the harder it is to define different classes.)

- Is the econometric model (Slide 4) a viable option?

  The simple answer is yes.)

- What is the basis of the econometric model (Slide 4) proposed by Dr. Woo – where does it get developed, how big is the population of data, what jurisdiction, etc.?

Dr. Woo did not provide detail on the data exercise. He did a survey of several pieces of literature that had econometric models that identified costs in relation to density issues. He chose one of those pieces of work, the econometric model in Lowry, Getachew and Fenrick, in which one of the cost drivers is customers per kilometer of line (a density measure) as an illustrative example. But he is not using this driver to define customer classes. As you vary this driver, you have a coefficient that says that costs vary with the number of customers per kilometer of line. He did not do an econometric study, but had a table which illustrates that if the coefficient is x, the impact is y. What he is really saying is that the data is available, which is true for the inputs he identified. The limitation is that his model is based only on OM&A costs, not capital costs.)

- If you could get over this limitation, how do you determine what the parameters are and what the coefficients are going to be?

  Dr. Woo's expectation was that data available from Ontario LDCs could be used. These LDCs have different drivers – different number of customers/kilometer. So the input data for the analysis would be Ontario LDCs. For example, you know how many customers and how many kilometers of line they have. The costs per customer for all the LDCs are known. You plug in the three cost driver factors he had and run his equation. To the extent that the identified cost factors explain differences among the LDCs, you would have a model that explains the price difference and has reasonable coefficients on the cost drivers. However, econometric models have many technical problems. If you mis-specify an equation, you will end up with misleading coefficients. Dr. Woo has tried to identify an equation which explains differences in cost based on density-related factors, but is this a full explanation of the cost differences across LDCs? So I would say that the econometric approach is a viable alternative in Ontario and the data is available, but you have to recognize the pros and cons of this approach and the potential technical issues.

- There are problems in looking at Ontario LDCs. Some costs that show up in the rural don't show up in the local LDCs. For example, Hydro One's enormous forestry program doesn't show up in most local LDCs. The City of Toronto has relatively high rates and extremely high customer density. This can skew results, so you have to be careful to compare apples with apples.

  I agree. This is the type of practical problem I was referring to when I mentioned potential technical issues in the econometric approach. If part of the explanation for Toronto's high costs is the heavy density of utilities under the streets (especially in the downtown area), and if this factor is left out of the equation, you end up with a mis-specified equation and an incomplete explanation of cost differences because you have not captured all the drivers. It would be very difficult to get an equation with all the cost drivers in order to get at just the density related ones that are relevant for urban and rural. With respect to the ToR, you may want to specify that if an econometric technique is used, that it must be deemed to be appropriate by the researcher for estimating the difference in cost between urban and rural service.)

- If the purpose of the study is to find the best cost allocation method that somehow incorporates density in a manner that is acceptable to the OEB, and you are looking for measurement errors in a method, you are ill advised to think in terms of a single model. You need more than one model to find errors. And you also have to look at more drivers than just density.

- In the last bullet on Slide 7, you should say "required", rather than "not ruled out".

- Are the suggestions on Slide 7 yours or Hydro One's?

  They are mine, not Hydro One's.

- Is there anything in the suggestions on Slide 7 that would be a concern for Hydro One? I also have the same question with respect to Jay Shepherd's letter.

  These are John Todd's ideas as to how we might move forward. Hydro One is open to a broad discussion and stakeholder ideas as to how we should move forward, and we can talk about this later this morning in the context of the ToR.

- John Todd is here today to speak to previous studies and the differences between the Elenchus and Dr. Woo studies. He will be leaving after his presentation and will not be present when we discuss the ToR, since Elenchus may be a bidder when the RFP is released later this year. So please limit your questions to ones of clarification and general expertise. (Facilitator)

- I understand how urban and rural definitions came about for utilities as people organized into towns. But I don't understand how this has anything to do with cost causation. I would like some discussion as to why the standard practice should be honoured and how this is fair to customers. In Ontario, we have gone from having municipal systems that, with the exception of police villages, generally were based on density because municipalities basically provide high density services. How do you handle the issue where you have a Brockville (a relatively tight municipality), and a Timmins (which used to call itself the largest city on earth), or a Huntsville where you have a large number of cottagers (urban folks, maybe on bigger lots) that are just outside that boundary who are getting a rural rate?

  In my OEB evidence I suggested that conceptually we should get rid of the urban/rural split. The OEB's directions do not seem to be in conflict with that. Most other jurisdictions have one company serving an entire area. Ontario has many LDCs; hence, there is an issue of comparability for Hydro One that is quite unique to Ontatio. From a rate design perspective, Ontario does not have distance-based rates even though the cost of serving customers who are further from a transmission line is greater. The OEB has explicitly said we don't want distance-based rates. There are many ways in which customers who are essentially residential differ, and the cost of serving them differs. But we do not break up the residential class into sub classes based on those cost drivers. I could not find a rationale for the urban and rural density-based definitions, or anything that is different about this split from other things we don't use to create sub classes. The OEB direction has not asked whether we should have an urban/rural split or even whether Hydro One should consider changing the definition. But to do what the OEB has asked Hydro One to do, it is difficult not to ask the question whether the definition is right or *whether it is something we can work with. So what I said in my evidence was that it might make sense to expand the scope to look at how we define urban and rural and whether we can come up with a more standard way of doing it, but it will be imperfect unless you are prepared to go to the trouble and expense of a high level of granularity (for example Google maps to identify areas of high/low density for all LDCs). Since this is likely not a practical approach, we are looking for a simplified way to draw boundaries around urban and rural areas. I have suggested municipal boundaries because this approach is based on using or adapting provincial rather than Hydro One definitions of urban and rural, thereby providing a certain independence or neutrality for the definition .*

- Aren't you saying that Hydro One should abrogate its responsibility and simply follow Mike Harris's plans?

  We have to do something. This is my suggestion, but it is not my decision.

- The OEB's direction was to look at the effect of density on customer classes. It did not say give us a new definition of urban and rural. It didn't even use the words urban and rural. It might be better to start the conversation about the study with different words. Historically, the urban definition was developed by Hydro One not to produce a cost-based definition for customers but rather to stop amalgamations from other utilities. It was a defensive posture that Hydro One took around Ottawa and London to give away the least number of customers. So rather than have political elements drive urban and rural definitions, I would prefer that we follow the OEB's direction to look at density and see where that leads once we get into the data.

- The OEB did not ask that the definition be looked at. That is precisely the point. There is no cost justification for the current density definition. There is also no cost justification in using municipal boundaries. You may find that if you identify the proper cost drivers, municipal boundaries might be the right breakdown, but this should flow from the driver analysis rather than being the starting point of the process. Similarly, Dr. Woo's analysis assumes that customers/kilometre is the cost driver, which may not be the correct assumption to make. Maybe the first thing the consultant should do is look at cost drivers.

- The natural gas distribution industry does not serve rural customers because it is too expensive. In the telecom industry the monthly charge for a rural customer is far less than for an urban customer, the reverse of what happens in the electricity sector. It might be useful to look at how the telecom industry does it its cost allocation between urban and rural.

  The conceptual basis for cost allocation on the telecom industry is completely different from the electricity sector. In rural areas or small towns you pay a lower monthly fee because fewer of your calls are local. The basic monthly fee is a bit of a proxy for how much of your calling is local versus long distance. It is more of a value for service than cost of service concept. (John Todd)

- Neither John Todd nor Dr. Woo's analysis commented on Hydro One's further breakdown of the rural class into R1 and R2.

Neither of us commented on it. The concept is that there is a continuum – the lower the density, the higher the cost. The equation reflects this. The question then becomes where are the cutoff points? The convention elsewhere is that you simply have urban and rural. So if you want to study the cutoff points, finding the cost differential between R1 and R2 is difficult. There is also the complicating factor of the Rural and Remote Rate Protection (RRRP). So as some have suggested today, there may be an argument for staying with the current definitions, regardless of the rationale behind them.

- In your evidence, did you look at how other jurisdictions outside Canada and the U.S. deal with density and cost?

  I have in the past, but not for the work last year. We have done a number of cross-jurisdictional studies which suggest that other countries have very different regulatory regimes and therefore don't tell us much about how we should do things here.

- We should have a component of the study that addresses at an early stage whether it is possible to reach rigorous conclusions. It is quite possible that the data is sufficiently fuzzy that regardless of how good the models are and how thorough the work is, it may not be possible to reach rigorous conclusions. The data may simply not support the conclusions the theory points to.

- *This segment of today's meeting was to recall the history and how we got here. In the absence of Jay Shepherd to provide the Dr. Woo perspective, Hydro One asked John Todd to try and refresh our memory on this piece. Is there anything in the history that John Todd hasn't covered, is missing or we should be aware of?*

- I don't think the OEB necessarily agreed with either the Elenchus or Dr. Woo evidence when it came out with its conclusions. What the OEB said in its last report is what got you to this meeting today. The OEB has given you your marching orders in terms of what it wants to see. I think the key thing is what Henry Andre will cover in the next presentation.

- Since Dr. Woo and Jay Shepherd are not here, have the studies been fairly and accurately captured? Are we missing any key elements of the study?

- I think John Todd was quite fair to Dr. Woo.

NOTE: John Todd left the meeting at this point.

Distribution Density Study: Background and Scope of Study Discussion

- The first quote from the OEB directive on Slide 2 is the key one.

  Agreed.

- It is worth noting that the "1.00s" for the last four customer classes in Slide 6 are not the result of applying a weighting. They were simply set at 1.00.

  That's correct. Those classes are not density driven, so we simply set them at 1.00. Hydro One has also suggested that seasonal customers should have their weighting factor set at 1.00 because it is not a density based class. However, the OEB said in their decision that we should maintain the existing weighting factors that are in the current model.

- Why are there three residential but only two General Service classes (Slides 4 and 6)?

  Need to distinguish the residential customers who get the Rural and Remote Rate Protection (RRRP). All R2 customers get RRRP. R1customers (greater than 100 customers/customer cluster and more than 15 customers/kilometre) do not meet the legislative criteria. (Henry Andre)

- Some General Service customers (GSe and GSd) also get RRRP, for example farms with a house.

  When the current four year rate harmonization process designed to get us to a consistent set of rate classes is complete at the end of 2011, current GSe/GSd farm customers who get RRRP will be moving to R2. Under the new approved rate classes, only R2 customers will get RRRP after 2011.

- What OEB decision is the moving of GSe/GSd farm customers to R2 based on?

  This was part of the 2008 Distribution Rate Application. I believe the move to R2 resulted in a net reduction for farm customers previously in the General Service class. (Henry Andre)

- Would you do the three tasks on Slide 8 (density definition options, develop data collection methodologies, collect data) sequentially or simultaneously? Would you define the density options and then find the data, or would you look at the data and start to define a category or list of potential density definitions.

  It is a good point and a bit of a chicken and egg problem. If you can't get the data, why even consider that option. You have to have some confidence that the necessary data can be found to assess the options put forward. Nevertheless, I saw the three steps taking place chronologically.

- Looking at the data may lead to the identification of some additional definitions or taking some options off the table.

  I take your point, but perhaps you are confusing collecting the data (Slide 8) with data analysis (Slide 9). The data we see collecting is what drives costs, such as density, asset age, etc. At some point you have to analyze the data and then come to some conclusions as to what classes make sense and potential weighting factors, and then run the data through the cost allocation model to get a sense of the customer impacts.

- The OEB asked you to look at the relationship between density and cost allocation. If you are doing things chronologically (Slide 8), the second bullet (develop methodology to collect data required to assess relationship between costs and density for various density definition options) needs to comes first and needs to be divided into two pieces. Hydro One currently uses certain definitions (customers/kilometre, etc.) as cost drivers. The first question therefore is, are these the appropriate cost drivers to reflect differences in density across the province? In other words, establish the relationship between cost and density. Then it is a matter of determining what data can be collected that would allow you to put some quantification to those cost drivers and understand how these drivers vary across customer classes. Once you have the cost drivers and understand how they vary, you go to the first bullet (develop options for density definitions) and look for "natural or unnatural" density definitions that fall out. Having identified two or three definitions on this basis, you would then proceed to determine the implications of using these definitions (Slide 9).

  What data do you see getting collected?

- Perhaps Hydro One has the right cost drivers and obviously you have to have data on the cost drivers you are using. Hydro One has good data for various customer classes such as customers/kilometre for all its feeders, MWH/kilometre, etc. The question is, are these the appropriate cost drivers? How do a few versus many customers in an area affect the assets needed to serve those customers, and what is the cost? Are the existing cost drivers the right ones, or are there better ones, and if so can you get data for them? If I were to plot customers or MWH per kilometre and came up with a totally linear line, I would have a problem delineating classes because there are no natural break points. But if I had clusters, I could find natural break points and group like customers and separate unlike customers.

- It would be useful to have an explanation as to how the weighting factors (Slides 4-6) were determined.

  I can provide a slide on the methodology as part of the meeting notes (Appendix 4). It is geared to looking at the number of customers within a class that are supplied by various feeders, and how much of the feeder length they take up.

- Could you include in the study scope (Slide 8) other jurisdictions outside of North America with similar demographics, geography, trends over time (urban and rural areas) etc.

The Elenchus Phase 1 Study provided a review of what is out there in other jurisdictions in terms of policy issues and criteria driving differences in costs. Further review of other jurisdictions is unlikely to be helpful in addressing the OEB's direction to complete the study. However, trends over time are a factor that the study could address.

- Hydro One's service costs are impacted by where it chooses to locate its service depots. Everyone thinks it's more expensive to put in a transformer on a farm because it is farther away. If the service depot is in Wingham, it is more expensive to replace a transformer in Exeter where there is no depot, effectively making this a rural service call. The marginal cost of maintenance therefore has more to do with the proximity of a service depot than urban versus rural or density. The fact that Hydro One chose some years ago to centralize its service depots may have saved some costs but boosted other costs. So one of the things you should look at is not urban versus rural but the cost of getting to the customer wherever they are. I think you will find that you have a lot of urban customers that have the same or higher service access costs as rural customers.

- So what specific data should be collected? (Facilitator)

- Travel distance to the customer from a service depot. Hydro One has about 40 service depots in 13 regions. Each depot will have distinctly different average service costs. The cost of a transformer and installing it once you are on site should be known. The travel cost is not density related because there will be long distance travel to both urban and rural areas. If you don't look at both density and where you put your depots, you will think that the cost driver is the rural area.

- It is a matter of identifying the critical cost drivers. Capital costs account for half the costs in the system and are more critical to get at than OM&A cost.

- Capital cost may prove to be the most important driver. However, eliminating OM&A to focus on capital cost is irrelevant because the key thing about capital cost is when the asset was installed. If asset age is included as a driver in the study, I think you will find that the rural installations are on average much older than higher density installations because the latter are things like sub divisions around Wingham that were built in the late 1980s not the 1940s and 1950s. So the rural services were paid for long ago and the interest cost is no longer there. The capital costs are in the high density areas. So you need to look at the age of capital in urban/rural, higher/lower density. Asset age and distance to a service depot will be far more consequential than the number of pig farmers per kilometre.

- We have to be practical about what data we collect. We could spend a lot of time getting greater granularity only to find that the cost cannot be passed on to a customer group. Does the data that some have suggested we collect even exist for us to harvest from? Does Hydro One track the cost of travelling to a customer from a service depot for all the service areas across Ontario? I doubt it.

I would have to check. I know we are getting a lot more detail as a result of the new systems we are putting in place. The consultant will have to meet with Hydro One staff and get an understanding of what data is available.

- Yes, getting a handle on what data is available is an important step in order to understand what is possible and practical, now and in the future. Density will have to be studied and re-assessed perhaps every five years. There will be outliers and issues, and people will at the end of the study not be happy about how costs will be allocated.   My concern is practicality and the cost/benefit of trying to get data and costs, and whether at the end of the day any of this can be allocated to customer groups. My biggest concern is the impact on customers. As for looking at jurisdictions outside North America, we have looked at this, for example with smart meters. Ontario is different to some extent, so we need to stay within North America. We even have difficulty comparing LDCs within Ontario. There are options for getting data. We have a lot of cost data - the PEG (Pacific Economics Group) report that the OEB has, the triple Rs (Reporting and Record Keeping Requirements) that the OEB has processed that we can get from the year book information, the OM&A data, and the assessment of costs across the LDCs in Ontario. A lot of people were unhappy with some of these methodologies. I think we should use the data that is already available through the OEB and other avenues.

  I think there has been some confusion about what the first bullet on Slide 8 means? Before you can say what the relationship is between cost and density, you need to know what you are going to look at for density. Even though the OEB says distance isn't going to be a factor, should it be distance? If so, you need to have gradations if you are going to gather costs by some split, you need to know what the splits are. This is really what the first bullet is saying. How do you want the costs broken down? What are the options – customers/kilometre, distance from service centres, etc.? We may want more than one, but before we go out and look for data we need some ideas about how you want us to break things down. To the extent that these are different from what we currently do, we may have to go to the OEB and say that we have done our assessment and talked to our stakeholders who have suggested we use a new method. If, for example, this new method were distance (which the OEB does not want us to use), we would want the OEB to know about this before we proceed with the study so we are not subsequently told that they didn't want us to look at distance and we are using the wrong density definition.

- Perhaps the elephant in the room is the current definition. Maybe the first task of the study is to blow out of the water or validate the existing definition. If you blow it out of the water, use the work and data that got you to this conclusion to suggest alternative definitions or criteria. Given what John Todd suggested this morning, perhaps we are talking about the sample approach using Hydro One data that to some extent exists or could be developed, in which case you could take a sample of the areas that are now charged density based rates versus those that are not. I think you have to go after that initial definition and once you have validated it (or not), or said that it was made up in the sixties and doesn't make sense today, move on from there.

  What does "validate" mean? If we find that there is indeed a differential, that the costs are different for different groupings, is this validation? This would not mean that there aren't better *groupings with more differentiation. It just says that these give you differential costs. These are bell curves with good differentiation between them. Is that good enough?*

- What I meant by validate is that the data shows that you have a good definition or that you don't have the best definition and that there is a different definition that is close to that one that is even better that we developed because of the work that you did to validate the initial classification.

- The OEB gave you a clue as to one the first things you could do at a minimal cost. They want you to compare costs of distributors similar to the ones you acquired. That would be fairly easy to do. You have your definition of urban density and you must be able to find utilities that are still independent that could be compared to those urban density clusters. This would tell you whether the rates you've set for those clusters are in the ball park or not and what you are going to have to do. This would tell you if you are on the right track.

  The acquired LDCs are fully integrated into Hydro One's system and are no longer being tracked separately. But we certainly know the area that they represented. We could take the sample area that was formally an acquired utility and try to estimate what it costs to serve this area. But the costs themselves are not tracked by the former acquired utility.

- I would be careful about taking the clusters that were bought up by other utilities because there may be cross subsidization going on. You should be able to find similar utilities that are still independent and look roughly the same as one of your acquired utilities.

  Are you suggesting that doing this would achieve the objective of comparing density and cost allocation?

- It will give you a clue as to whether the rate you've set for urban density is correct and whether the criteria used make sense. Someone suggested earlier that there was no basis for setting up the urban density class in the first place.

  You are getting into something we do not all agree with. (Susan Frank)

- I did not say that the creation of the urban class was wrong, but that the way it was done and the motives at the time were not based on strict cost causality and trying to get fair allocation for everyone. It was done in the knowledge that the urban class would sit outside rural rate assistance. With respect to regional variations mentioned earlier, my sense is that this may not be a good approach because of the policy constraints.

  What do you mean by policy constraints?

- We would be opposing provincial policy, even though it is more costly to serve customers in the North than in the south for a variety of reasons that are driven by latitude (geography, climate).

- With respect to the service centre issue mentioned earlier, this is a chicken and egg thing. I assume that Hydro One attempts to minimize service costs by optimizing where it locates its centres.

- Traditionally, Hydro One has looked at density with two surrogates - transformers and kilometers of line. You may want to break out your major capital and OM&A program costs. For example, forestry seems to be growing faster than in the past. The issue of whether you should look at past or future costs was raised earlier. When you are busy changing your programs to deal with things like reliability and aging assets, an understanding of future costs will help to set rates that will stand up over time. Many of the acquired LDCs had well aged assets in stable areas.

- On the issue of gathering the data versus choosing the methodology, to the extent that you think you have data that may be a driver of cost, you want to gather as much such data as possible and do relatively "unstructured" analysis without specifically asking preset questions. Technology is available to analyze data and find things that you may not have thought were there. You may find things in the data that tell you there are drivers more important than density.

  So it is how you mine the data?

- You may actually want to get someone who has no utility experience.

- One of the problems with North American utilities is that they have tended to be inward looking and reluctant to look at other jurisdictions. The OEB has suggested you look at other distributors in Ontario similar to your acquired LDCs and I doubt the OEB would be concerned if you also looked at an analysis of similar utilities in other jurisdictions that have different regulatory regimes. In fact, because they have different regulatory regimes, they may have more clearly identified costs based on density and perhaps other factors that could be applied in Ontario. I would also include in the scope some reference to the green energy plan and the implications of the Smart Grid. For example, there might be a school in a remote area that thinks it is paying too high a rate for electricity. What if this school were to take advantage of the MicroFIT program and install solar collectors, thereby receiving 80 cents/kwh for power it puts into the system beyond its own needs. Hydro One would have to get that power to your customers in the area, with implications for the system.

- A practical and efficient way to get at data and the real cost drivers might be to use differential analysis. There are about 40 service centres, each with different densities, travel costs, customer mixes, etc. Presumably Hydro knows in detail what gets spent by each centre. Differential analysis would produce an extremely accurate picture of costs/customer time at each centre. You could add for each centre your weather and forestry events, planned/unplanned outages, etc. Your first cut analysis would therefore provide a great deal of detail on cost factors by customer class and by program, the things you already track. You know your cost by operating centre, and if you know your historical capital cost by operating centre, you would have data that I doubt could be matched by sampling or any search of individual records. If you have more than 20 service centres, you will have tremendous statistical rigour. Fewer than ten might be a problem.

Are you suggesting that rather than using density of customers, we use the physical location of assets, and that customers connected to those assets would have different rates?

- Density will be one of the factors that you will know by service center because you know how many customers, customers by class, average travel distance, how much line, etc. you have per centre. You also know the number of trees/sq. mile, how many trees are close to lines, average age of assets, etc. by centre. Differential analysis will generate very detailed and quite precise indications about the relative importance of the relative costs of each of these factors. This approach will be low cost and will quickly tell you what the real cost movers are, of which density will likely only be one. And if density is not a key cost driver, you will know pretty quickly.

- You said you expect the study to be finished August 2011 (Slide 10) and that you intend to submit it in evidence as part of the next cost of service application. Does this mean near the end of the application?

  No. We will not be filing in August. It will be later than that.

- Don't you need to get 2012 rates?

  We intend to file late in 2011. There are issues in 2011 with Hydro One in particular that will make it difficult to file a distribution application earlier in 2011.

- Will the results of the study be part of the pre-filed evidence? (Facilitator)

  Yes.

- Do you intend to seek more stakeholder input on the study?

  We would provide an update on the study as part of the first stakeholder session on the cost of service application.

Prepared Questions Discussion

1. a) Is now the right time to study rate classification/density (in light of pending TOU rates, Smart Meters, rate increases, etc.)?

   b) How much tolerance is there for rate changes at this time?

2. Is density an appropriate factor to define rate classes?

3. Are there factors other than density that distinguish urban versus rural rate classes?

4. Is there value to more precisely determining the costs applicable to existing density-based residential classes?

5. What are the cost factors applicable to urban and rural rate classes?

6. How precisely should the data collected in the study reflect actual cost of service, and how should these best be determined (e.g., using sample data from Hydro One, using benchmark data from a variety of LDCs, engineering analysis, connectivity analysis)?

- *Rather than eliminating question #1, since Canadian Manufacturers and Exporters (CME) is in attendance today, I would be interested in hearing their reaction to #1. We've heard about their reaction to things that change rates.*

- Are you referring to CME's pre-filed evidence? Is this the evidence that you are proposing on relevance?

  Yes, your pre-filed evidence. We're saying that the CME is concerned that there are many things that are impacting customer rates today, so should we move on those items that will impact rates when we know that this study will have no impact on our overall revenue requirement but some customers will see increases while others will see decreases. Is the CME supportive of driving differences because of the allocation study at this time?

- The CME sees this as an issue that was decided two years ago and again in the last rate case. The OEB has made it clear that it wants this done. It is not up to the CME to now say that this shouldn't be done. We are looking forward and just want this study done in a cost effective manner. So let's move on.

  So is the CME supportive of differing rates based on a study like this? Why do it if there is opposition to changing rates?

- I think we need to see what the study says.

  It will change rates.

- Fair enough, but we don't know how it will change rates. We will not oppose the study simply on the basis that it will change rates. We need to see the study results. The OEB has made a decision to have the study done. It didn't say change the rates.

  But if we knew that we don't want class allocation to change rates, we would write to the OEB and say that there is no sense in doing the study and incur the cost if we are not prepared to change rates on the basis of cost allocation.

- CME cannot take the position that we don't ever want to change rates. We are not opposed to the study. Let's see what it says.

- So the CME is saying that there is an interest in getting greater clarity around density and cost allocation. (Facilitator)

- Yes. The CME has publically supported doing the study in accordance with the OEB's direction in previous rate cases. Is anyone opposing conducting the study?

  Not officially.

- There may be people who take issue with the way that the study should be done, but the CME does not oppose doing the study.

- The Green Energy Plan will have a huge impact on Hydro One's cost structure, including distribution, in the years ahead. It will impact Hydro One far more than any other utility. What is the point of doing the study now if Hydro One's cost structure may change because of the Green Energy Plan? You would have to do the study all over again. And with the Green Energy Plan coming down the pike, you do not want to change rates tomorrow.

- So what you are saying in terms of recommendations regarding the scope of the study is: (Facilitator)
  - consider the impact of the Green Energy Plan
  - to the extent possible, consider the future as well as the past
  - a better understanding of the relationship between density and cost allocation does not imply that rates need to change immediately

- *I think there is a fourth point. Why do the study now based on the current paradigm if the environment is going to change so much that the results of the study may not be valid and might have to be re-done.*

- That raises the question of the level of effort that should be put into the study if you do the study now (Facilitator)

- I think you do a "quick and dirty" study and submit it to the OEB.

- The differential analysis approach will give you a cost effective and relatively quick method to identify the cost factors. I don't think there are enough green energy customers, apart from conservation (which is simply load shifting) to make a significant difference to Hydro One's cost structure. Green energy is one of several hundred cost factors and will not have a significant impact on outages, or weather, or trees. In distributed generation, we have 16,000 solar panels if they all get built. This will not have a big impact on a million plus customers. Are there factors other than density? Almost certainly, and they are asset age, distance, the location of service depots, etc.

- I think you need to look at the "topography" of the system in relation to customer groups. For example, in many of the small utilities that Hydro One bought the customers are fairly dense but served by fairly inefficient systems (lots of losses, more station maintenance costs over the long term). In some of the rural areas, the feed is now directly out of transformer stations and sub-stations are no longer needed. You may find that when you look at the total topography, not all the costs are going in one direction towards high density, but in the opposite direction. Look at the major elements of cost. What we have in Ontario is history, with half a dozen different voltage levels that were brought in over time in different parts of the province, and over time a lot of the old stuff has been taken out. Ten years ago, Hydro One bought a lot of assets that had not been harvested for a long time. These were old, high density and perhaps higher cost to maintain. They may even have higher costs associated with them than some farms that don't even have a sub-station associated with them. This isn't a simple distribution transformer and rural line issue. It is about what assets serve specific customers.

- Vegetation management costs are very significant in the rural areas and almost nothing in urban areas of the system and should be allocated accordingly.

  Would you agree that another big element of Hydro One distribution costs is storm costs? A big factor in outages during storms is vegetation.

- Storm management costs are related to poor vegetation management programs. They are very closely linked. If you were up to date on vegetation management, you would not have so many storm outages. Last weekend I went through an eight hour outage, and they had just cleared the line but they missed a few trees which fell during the storm.

  We are trying to get the cycle down as short as possible.

- We have talked about using the sample method to get costs. Perhaps if you find that the data is not very good or meaningful, or that the data is hard to get using this approach, you could use engineering studies and simulations as a secondary approach. This might give you data from two different perspectives. I said earlier that you could test the current density definition to see if it is good or bad, and maybe you come up with something else. As we saw in the evidence from Elenchus and Dr. Woo, everyone else uses municipal boundaries rather than density. So if necessary, I would say that the last step in the analysis is to consider the pros and cons of using municipal boundaries in Ontario.

- Your suggestions are really about methodology and address question 6. (Facilitator)

- Does Hydro One have a sense for the impact on the cost of the study in relation to which approach is used – sampling, engineering, econometrics?

  We have not yet priced the study and we have not looked at what it would cost as a function of the three approach options. We initially thought we would use a single approach and one that provided rapid results, keeping in mind the OEB's direction regarding timeliness and cost efficiency. We had not considered multiple approaches, although that suggestion has been made today.

We have looked at and attempted to do this study before. Our initial sense when we assumed a simplistic single approach was that the study costs would be in the $250,000 range. Once you assume the need for more detailed and better data, multiple testing, feeder information, etc., you are likely in the $1- 1.5 M range. So this is not an inexpensive study. We would like to only do it once and then put the issue aside for 10 or 15 years. We don't want to have to repeat it. You will not get what you are asking for, for $250,000.

- Clearly, we must balance cost effectiveness with how much work we do. Once you get an idea of what the cost will be, I think you should come back to this group or the OEB with your assessment of what you think is cost effective to do.

What is cost effective? What is the upper limit?

- I don't know. I can't tell you in a vacuum.

- How long has the current rate design been in place? Perhaps 30 or 40 years. Has it ever been looked at in all this time? Very little money has been spent in all these years to look at this question. Maybe this should be taken into account.

The OEB probably has a better idea of costs because it had some proposals and started a rate design study and then stopped or delayed it.

- Density was not the issue in that work. It was more about fixed and variable costs in the context of harmonization. We are going back to at least one hearing prior to 2008. Customers in acquired utilities were assigned to Hydro One classes. The question that was being asked was how these classes to which customers were being assigned got formed in the first place because there were significant bill impacts (arbitrary 10%/year bill increases during the phase-in years). The short answer as to how the classes came about in the first place was that nobody remembered and that it might have had something to do with cost. Density-based rates and factors were really inherited, so the OEB was asked and did take a lot on faith. The OEB has never said do away with the existing system, but show us that it is a good idea and that it is better than the alternatives.

- We are actually doing two things. Hydro One has a cost allocation system that allocates certain costs using a density parameter. You could do that even if you had only one residential and one general service class. You could still use the density cost drivers to come up with different costs for each class and have an average rate for each class. Secondly, within those broad classes perhaps there is such a vast range of customer density that it might be worthwhile breaking them up into more than one class. Then you have to ask whether it is worthwhile splitting up the classes and what is the best way to do it. This study will do two things: how should we allocate costs (should we use a density-based cost driver to allocate between classes?), and what is the best definition of classes. These are very different questions but they both need to be addressed by the study.

- There was a question of cost effectiveness and how you measure it. Total distribution costs will remain the same. We don't expect to see a saving. But we should expect to see higher costs for customers who have been benefitting from hidden cross subsidies related to density or other factors, and lower cost for customers who have been paying that cross subsidy. When the study reveals these facts, a decision can be made with respect to the efficiency of either continuing or reducing or removing the cross subsidy. The density-related cross subsidy might be economically and socially productive or it might be shown to be destructive. This is where the cost effectiveness comes into this. If the cost of the study relative to the improved system efficiency over the years is low, then it will have been cost effective.

- I think there are two elements to cost effectiveness. Without looking at what the results will lead to, how much is this study going to cost? It will cost different amounts depending on whether we buy the Lamborghini, the Mercedes or the Pinto. We could go into a level of granularity to the point where the study has no return at all. I think we should ask how detailed the study should be in relation to the cost, and whether the price tag will be worth it.

  The bigger the scope the more it will cost. At some point you have to say the scope is too big, so rein in the scope or the cost will be too high.

- The other issue on cost effectiveness is that once you have the study results, you have to ask yourself whether it makes sense to change the status quo, given that there will be winners and losers. Is it worth doing? We have to look at this after the study is completed.

  Does it make sense to spend perhaps $1.5M if we are not prepared to have winners and losers and make changes to get closer to cost driven rates? If we are prepared to make big changes, then we need to get it right and that is an expensive study. If we are only prepared to do minor tweaking, perhaps we do a "quick and dirty" study. The extent to which we are prepared to make big changes seems to me to be the basis on which we should decide how much money we want to spend on the study.

- It is difficult to make decisions in the abstract and without knowing what the study will say. We can't say yes or no to big moves at this point. The OEB has said that this study is necessary and that they want it done. We can't make a decision about change in a vacuum. We need to see the study results first.

- Since the outcome of the study cannot be known before it is completed, can we give Hydro One a reasonable guideline in terms of the cost effectiveness of the study or an upper limit on its cost? (Facilitator)

- I think we are confusing change with shock. The biggest change that residential customers have experienced in recent years has been harmonization. The OEB and Hydro One were very careful to spread that out over time. If the study recommends big changes, it will likely be gradual.

- Do you have a suggestion as to what a reasonable cost would be to get there? (Facilitator)

- My criterion would be to do a study that produces results that provide the OEB with useful information and direction.

- Irrespective of the cost? (Facilitator)

- I don't think this is a $10M study.

- There are politics at play as well that need to be considered. Hydro One alluded earlier to filing late in 2011. This is probably related to the coming election. It may be prudent for Hydro One to file after the election.

- I believe that the study can be done using differential analysis at a reasonable cost – under $500,000. It will be worth it provided that people stick with the outcome and that the changes are phased in and that the transition costs are treated reasonably.

- Is there any disagreement with the earlier statement that the study should cost as much as it takes to get valuable and reasonably valid information? (Facilitator)

- We don't know how much it will cost to get valuable data at this stage. Surely there is something that is cost effective and will provide valuable information, but we can't simply agree to a blank cheque and say go get whatever you need and think is valuable.

- The sky is not the limit but surely we want to do this. There may be winners and losers, but what we are trying to do is come up with a more fair and accountable way of allocating costs.

- We are in favour of doing the study, but we can't commit carte blanche and in advance to have everything that comes out of the study implemented.

  My question was- if the study suggests changes and there are winners and loser, are you prepared to make some change? Or will you say this is not the time for changes with winners and losers because there are already too many other changes happening and we don't want another one. If we know today that we don't want any change, why do the study?

- Who knows what Ontario will look like when you file late next year. We are changing at a pretty rapid pace. I am not saying today that we don't want any change in the future. We will be having that debate in a year and a half from now, depending on what the study says and on the scope of the recommended changes, if any. The study may find the current density-based rates are appropriate).

  Our rates today are not cost based, and that is where we are going.

- I don't think the study is going to produce cost based rates.

Yes it will.

- Closer to cost based rates.

- One question is whether the study will tell you that you should be using different cost drivers or weightings in your allocation. If it does, it will impact the revenue/cost ratios for existing classes and the OEB has ways of managing this situation – modest adjustments every year or no adjustment, etc. The study may tell you to drill down further into the cost drivers which may reveal different ways to split or group customer classes so customers in the same class have similar cost characteristics from a density perspective. The study may also tell you that density is worth taking into account. We currently have different rates for R1 and R2, but we also have different load characteristics. Perhaps the load characteristics are driving the difference in rates as much as density. To date no one has really looked at this. Density may not be the critical issue. It may be something totally different. You have a system built around energy and you have different load factors, but we're looking at everything based on demand. You may come up with a different definition of cost, but I'm not sure how much this will help.

- On the Transmission side, Hydro One has spent a lot of money on studies and intervener funding (AMPCO) on very similar issues, no doubt well in excess of $200,000, and we still don't have answers. I think we need to acknowledge this and ask the question - what the most appropriate way is to divide up the pot.

  We are spending large amounts of money in our Transmission business to look at very similar issues – how do you change the allocation to make sure the right party pays. If this is the right time to do that in Distribution, we are ready to do so, and to do it carefully and thoroughly. I understand the earlier arguments that we need to use multiple approaches so that the results are comprehensive and defendable and we only do the study once. As long as I have some comfort that we are prepared to start some change based on whatever is determined by the OEB, I would feel that the money was well spent. What I struggle with is the concerns some have expressed today about customer impacts and that we may not be prepared to make any changes. The money will not be well spent if we are not prepared to do anything or if we are simply doing a study because it is interesting and informative. In the Transmission case, I think there is value in having spent a lot of money because I do think change is a possibility. I would like to know that this is the case in Distribution. I think I did hear the CME feels there is value in spending the money. I would still go to the OEB and say delay the study for green purposes because we don't know the cost and we will not deal with the customer impacts.

- You can't use the Green Plan to delay. On the contrary, because of the green issues we need to accelerate things.

- Let's get it done before the next election. We are prepared for winners and losers because this is normally how you reverse the current winners and losers. I think that Hydro One should have some time in the study schedule for stakeholder contact with the contracted consultant prior to finalization of the report.

- Can you clarify what you mean by "before finalization of the report" and what the objective would be? (Facilitator)

- Stakeholders should meet with the consultant and Hydro One when the results of the model have been run. There may be other items that may need to be taken into consideration. This would be similar to what Union Gas is doing right now.

- I would be concerned that meeting with the consultant might skew the results of the study. My concern is that I'm not comfortable with the current ToR and I think it's important to get them right. Could we have another iteration?

- Getting stakeholder input on the ToR was the purpose of today's session. Are you saying that once today's input has been incorporated, send the ToR around to stakeholders again? (Facilitator)

- You could do a quick scan in advance for probable winners and losers of all kinds, not just density related – low volume demand customers, remote customers, customers who have more than one substation serving their area, etc.

- Maybe we should be using different language than winners and losers. We may want to say that people who have been underpaying in the past will be paying something that is a little closer to what they are actually getting.

- It may be worthwhile to touch base with stakeholders at the point in time in the study when you are defining what new customer classes/breaks/groupings/definitions you are going to test based on the analysis of the cost data that you got. There is a lot of time and work involved in running these through the cost allocation model, so you don't want someone to say later that you didn't run the right ones. It would be useful to get some agreement in advance before doing the detailed analysis.

- Think about how accurate the results have to be and how granular a solution we want. Different degrees of resolution produce different costs. It may be a bit easier to get on with the study if you start with a bandwidth of plus or minus 15% of cost to split out groups.

- It is still not clear to me whether the study will only look at customer classes that currently have density-based rates, or will it look at the entire retail system (sub transmission, street lights, distributed generation, seasonal, etc.).

  The intent is to focus only on the current residential and general service classes, but as was mentioned earlier, the data may suggest different ways to split classes.

- The first thing to do is identify what the cost drivers are and then figure out where it makes a difference in cost allocation in distinguishing customer classes.

APPENDIX 3

MEETING EVALUATION FORM

and

CONSOLIDATED RETURNS

2012/2013 Distribution Density Study

Stakeholder Consultation

Consultation Evaluation Form

This session was a follow-up to the May 2009 discussion initiated by Hydro One for the purpose of conducting a dialogue with its stakeholders regarding the 2012/2013 Distribution Density Study ordered by the Ontario Energy Board.. Your feedback is important to us. Please take a few moments to fill out this evaluation form.

Name (optional):____

Material presented in this session included an overview of the Density & Cost Allocation Study and Rate Implementation. Please rate each component by circling the appropriate number.

1. The information presented was clear:	Strongly Agree	Agree	Disagree	Strongly Disagree
Density & Cost Allocation Study	1	2	3	4

Comments:

____

____

2. I had adequate opportunity during this session to share my views with Hydro One on:	Strongly Agree	Agree	Disagree	Strongly Disagree
Density & Cost Allocation Study	1	2	3	4

Comments:

____

____

Please turn over…

Thank you for your comments.

	Strongly Agree	Agree	Disagree	Strongly Disagree
3. Hydro One was open to the issues and recommendations I raised about:				
Density & Cost Allocation Study	1	2	3	4

Comments:
____

____

	Strongly Agree	Agree	Disagree	Strongly Disagree
4. Overall, this consultation session met my expectations:	1	2	3	4

Comments:
____

____

	Strongly Agree	Agree	Disagree	Strongly Disagree
5. Overall, the preparation package was thorough and included all relevant and essential information for the session:	1	2	3	4

Comments:
____

____

Please provide us with any additional comments you may wish to make:
____

____

Please submit your completed forms before you leave, or fax to the number below **NO LATER THAN September 15, 2010.** If you have any comments or questions, please contact: Ms. Enza Cancilla, Manager, Public Affairs, Tel: 416-345-5892; Fax: 416-345-6984 Email: enza.cancilla@HydroOne.com

Thank you for your comments.

2012/13 Distribution Rate Application
Density and Cost Allocation Study
Stakeholder Consultation Session, September 8, 2010

Six participants submitted comment sheets after the session was concluded. The table below presents the comment sheet responses received.

	Strongly Agree	Agree	Disagree	Strongly Disagree	No Response
1. The information presented was clear.		5	1		
Comments	• Good summary – assisted in the discussion. • Suitable to get discussion started, but several preconceptions created confusion, took time.				
2. I had adequate opportunity during this session to share my views with Hydro One.	4	1	1		
Comments	• Too short. • Very open and animated discussion.				
3. Hydro One was open to the issues and recommendations I raised.	1	2			3
Comments	• Hydro One was looking for input. • Remains to be seen. • Energy Probe suggested a meeting of intervenors with the appointed study consultant prior to preparing the report. VECC supported this. No response from Hydro One to date.				
4. Overall, this consultation session met my expectations.	1	4	1		
Comments	• Poor facilitation.				
5. Overall, the preparation package was thorough and included all relevant and essential information for the session.		6			
Comments					
Additional Comments	• Difficult issue and topic. Well done! • Shall send a list of service depot parameters.				

APPENDIX 4

DENSITY WEIGHTING METHODOLOGY

Excerpt from Exh. G2, Tab 1, Sch. 1 of Proceeding EB-2009-0096

3.0 DENSITY WEIGHTING FACTORS

Density factors have been incorporated as weighting factors for Overhead lines and Transformers, consistent with the customer classes approved by the Board that are based on Density definitions. The Density definitions are unchanged from Proceeding EB-2007-0681.

For lines, Customer Density weighting factors were developed by calculating for all feeders the number of customers by customer class on each feeder and assigning the total distance of the feeders to the various customer classes proportionally. A similar method was used to develop Demand Density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the feeder length for each feeder to customer classes proportionally.

For transformers, Customers Density weighting factors were developed by calculating Net Book Value of Transformation Assets by feeder and assigning the total Net Book Value of Transformation assets by feeder to the various customer classes proportionally. A similar method was used to develop Demand Density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the Net Book Value of Transformation assets for each feeder to customer classes proportionally.

Interrogatory Response Exh. H, Tab 12, Sch. 66 in Proceeding EB-2007-0681

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 2

Preamble: *Section 3.0 outlines the approach used to determine the density weighting factors for lines and transformers. The text states that for lines "customer density weighting factors were developed by calculating for all feeders the number of customers by customer class for each feeder and assigning the total distance of feeders to the various customer classes proportionately".*

Question:

a) Please provide a schedule that sets out all of the USOA accounts that are allocated in whole (or in part) based on density weighted allocation factors.

b) With respect to the schedule provided per part (a), please indicate for each USOA account the density factors for each customer class used in weighting customer and/or demand allocators.

c) Please provide more details as to how the density factors for lines were determined, such as:
- For which overhead lines (i.e. voltages) were density factors calculated? Related to this, for which categories of overhead lines (Sub-Transmission, Primary and Secondary) were density factors developed
- It appears that the analysis was done by "feeder". Please describe what the definition of a "feeder" is in this context. Are feeder voltages specific?

d) Please provide an illustrative example of how the Customer density weightings for lines were determined assuming a small number of feeders that represent the cross-section of the line voltages in Hydro One's distribution system with a mix of customer classes connected to each.

e) To what types of transformers are weighting factors applied for purposes of allocation? In contrast, what transformation facilities are allocated without the use of density weighting factors?

f) Was the same definition of feeder (page 2, line 15) used for the development of the transformer weightings?

g) For purposes of the transformer weightings, is the feeder identification used to associate transformers to feeders based on the high or low side voltage of the transformer? Please provide the rationale for the choice.

h) Please confirm that for the Transformer Customer Density weightings the NBV of the transformers on each feeder were assigned to customer classes proportional to the number of customers by class using the feeder. Please provide an illustrative example.

Response

a. The following USofA accounts are allocated with density weights.

1830-3B	Bulk Fixtures - Retail
1830-4B	Primary Fixtures - Retail
1835-3B	Bulk Conductors - Retail
1835-4B	Primary Conductors – Retail
1850-2	Rural Transformers

The resultant Net Fixed Assets [NFA] and Operations & Maintenance [O&M] are thus also impacted because these asset accounts impact the NFA calculation while O&M allocation "piggy-backs" on the relevant asset.

A full listing impacted USofA accounts is contained in Exhibit G2, Tab 1, Schedule 1, Attachment A, E2 TB Allocation Details pages 124 to 134.

b. The density factors per rate class are presented below:

	Lines			**Transformers**	
	Customer	Demand		Customer	Demand
UR	0.19	0.18		0.77	0.75
R1	0.66	0.64		0.93	0.88
R2	1.61	1.42		1.23	1.12
Seasonal	1.20	1.60		0.87	1.28
GSe	1.11	1.15		1.00	1.04
GSd	1.14	1.18		1.05	1.01

UGe	0.24	0.18		1.03	0.79
UGd	0.31	0.30		0.76	0.94
Dgen	1.00	1.00		1.00	1.00
ST	1.00	1.00		1.00	1.00
St Lgt	1.00	1.00		1.00	1.00
Sen Lgt	1.00	1.00		1.00	1.00

c. All lines were included in the analysis to derive density weights. A feeder is a distribution line. Yes, feeders are voltage specific in that they connect from a station.

d. The following is a simplified overview of the density weights derivation.

Connectivity data exists to connect customer by rate class to feeders. The length of the feeder is also known. Based on the share of customer per rate class, a portion of the feeder is allocated to the rate class. This process is done for all over 3,000 feeders and total allocated km per rate class are determined.

Based on the total allocated feeder km per rate class, the km/customer metric is derived.

The weights are then determined by weighing the km/customer by total customers as outlined below for each class grouping, (i.e. Residential, General Service energy billed, General Service demand billed).

<u>Connectivity Data</u>

	Feeder	Km	Class 1	Class 2	Class 3	Total Class
	1	10	5	20	10	35
	2	20	10	10	20	40
	3	30	15	5	20	40
	4	40	20	5	10	35
A	Totals	100	50	40	60	150

<u>Allocated km</u>

	Feeder	Km	Class 1 km	Class 2 km	Class 3 km
	1	10	1.4	5.7	2.9
	2	20	5.0	5.0	10.0
	3	30	11.3	3.8	15.0
	4	40	22.9	5.7	11.4
B	Total km	100	41	20	39
C=B/A	km/cust		0.81	0.50	0.65
A	Cust	150	50	40	60
D*	**Wts**		**1.22***	**0.76**	**0.98**
E=DxA (Check)	Wted Cust	150	60.8	30.3	58.9

D*= Wts 0.81x150/[0.81 x 50 + 0.5 x 40 + 0.65 x 60] = 1.22

e. The transformation assets captured under USoA 1850-2 for the Rural retail customers are density weighted. The small transformation balance that has been isolated to serve the ST class as part of USoA 1850-1 is not density weighted.

f. For the transformation density weights, the feeder length is replaced with connected rural transformation Net Book Value per feeder. The feeder definition is consistent with that for Lines.

g. The association of transformation to feeders does not consider the high or low side connection. Based on Hydro One's Distribution Outage Response Management System, each feeder is listed with attached transformers by size category. For each feeder, the number of transformer per size category is added up and an average net book value per transformer size is used to estimate the net book value of transformation attached per feeder.

h. Yes, for the Transformer Customer Density Weights, the NBV of transformers is allocated to rate classes proportional to the number of customers by class using the feeder. The example presented in Part d with feeder km replaced with feeder NBV would be an illustrative example.

Hydro One Networks, Inc.

Stakeholder Consultation Meeting Notes

Density Cost Allocation Studies in Support of Hydro One Rate Applications

March 22, 2011
Special Event Room, Ground Floor
483 Bay Street, North Tower
Toronto, Ontario

Prepared by London Economics International LLC and PowerNex Associates, Inc.

Table of Contents

1 Introductions and Review of Agenda

Enza Cancilla (Manager, Public Affairs, HONI) welcomed participants and provided an overview of the day's agenda. She then invited participants to introduce themselves. In attendance were representatives of the Association of Major Power Consumers of Ontario, Canadian Energy Efficiency Alliance, Canadian Manufacturers and Exporters, Electricity Distributors Association, Energy Probe, EnviroCentre, Federation of Ontario Cottagers' Associations, Horizon Utilities, Ontario Energy Board, Ontario Federation of Agriculture, PowerStream, Power Workers Union, Veridian Connections, and the Vulnerable Energy Consumers Coalition. Also present were HONI staff, and the LEI/PNXA presentation and facilitation team.

The full list of participants, together with the agenda, is provided in Attachment 1. Attachment 2 includes a copy of the presentation that was delivered by LEI/PNXA to stakeholders.

Ian Malpass (Director, Regulatory Support, HONI) welcomed participants and gave a quick overview of the status of the project. He encouraged participants to provide their ideas and perspectives on the proposed methodology that would be presented. He asked that participants identify themselves when making comments so this could be included in the notes of meeting. He then introduced Andy Poray (AP) of PNXA who would facilitate the proceedings.

2 Presentations and Discussion

2.1 Slide 2

AP provided an introduction to the presentation that would follow. He requested that questions be asked from the floor throughout the presentation.

These notes of the meeting make reference to the slides that were presented at the meeting and included in the package that was sent to stakeholders prior to the meeting.

AP noted that there were two general objectives for the stakeholder session:

- To reach a general agreement on the proposed methodology; and
- Receive specific feedback from stakeholders

He then introduced Benjamin Grunfeld (BG) of LEI and Mark Vainberg (MV) of PNXA to make the presentation.

2.2 Slide 4

BG reiterated that the objective of the session is to get general agreement from the stakeholders on the proposed methodology and to receive specific input from stakeholders. He reviewed the three objectives of the LEI/PNXA engagement and noted that these follow the OEB's direction to HONI for the density study. He addressed the confusion that sometimes exists related to characterising groups of customers specifically when using the word 'density'. Customer density is one specific characteristic of a group of customers (e.g. population density). This is not to be confused with other characteristics of customers groups. For example, a rural or urban description tends to include multiple characteristics (e.g. distance from major load centre, levels of vegetation, network topology). However, there is typically overlap between the two classification methodologies e.g. low-density customers also tend to be rural customers, which contribute to 'misuse' of the low-density term.

2.3 Slide 5

The existing cost allocation methodology allocates approximately $110 million of costs to R2 and seasonal customers from UR and R1 customers, based on current density weighting factors. If the density weighting factors were removed (i.e. set to one), $110 million would shift back to UR and R1 customers, which would have a material impact on per customer cost in all of the residential sub-classes. The UR and R1 cost per customer would increase by 81% and 23% respectively, while the R2 and Seasonal cost per customer would decrease by 22% and 12% respectively. The impacts are similar for the General Service Customers, if existing density weighting factors are removed. John McGee asked if these costs represented only the distribution portion of costs. BG confirmed this to be correct.

Peter Thompson inquired as to what the basis is for the shift of costs from one group to another. BG and MV explained HONI's current cost allocation methodology and the way in which the density weighting factors are calculated. Density weighting factors are applied to a number of cost categories. HONI first assigns a portion of the total length of each distribution feeder to each of the individual customer sub-classes. Feeder length is allocated to sub-classes either on the basis of i) the number of customers in each sub-class on a feeder relative to the total number of customers on the feeder or ii) the volume of throughput (MWh) delivered to each sub-class on a feeder relative to the total volume delivered on the feeder. The calculation is performed on individual feeders and then aggregated up to the sub-class level. The customer density (customers per km of line) for each rate sub-class is determined as the ratio of the total number of customers in each sub-class to the total assigned feeder length. Likewise, the energy density (delivered kWh per km of line) for each rate sub-class is determined as the ratio of the total consumption for each sub-class to the total assigned feeder length for that class. The density weighting factors are calculated as the inverse of the ratio of the sub-class specific density to the average density across the class. Transformer cost density weighting factors are determined slightly differently. Instead of the density weighting factors being calculated on the basis of an allocation of a length of an individual distribution feeder to a sub-class, the density weighting factors are based on an allocation of the net book value of transformers on a feeder to a sub-class

John McGee asked about the sub-transmission costs and if they are included in the rate classes being considered. BG responded that no, sub-transmission costs are not included and only the eight rate classes illustrated in this slide are impacted by density weights in the cost allocation model.

2.4 Slide 6

BG noted that HONI previously engaged Elenchus Research Associates to assess the impact of density on distribution rates.

In designing rate classes and cost allocation methodologies, one of principle objectives is to consider fairness. BG emphasized that one of the objectives of the study is to consider fairness in a number of dimensions such as:

- equal customers treated equally; and
- unequal customers treated unequally.

What is being proposed by LEI and PNXA is to differentiate customers based on the cost incurred by HONI in providing distribution services to different sub-classes through a comprehensive study providing evidence of a potential cost difference, thus providing justification for different distribution rates for different classes of customers.

The study will consider a number of specific questions and BG noted that this study will examine whether there is evidence of differences in cost to serve low and high density customers.

BG noted that there may not be a difference between the way rural and urban customers use electricity. Dana Silk disagreed noting that there are those who feel that there are differences in consumption of electricity between different customer classes. BG responded that that may be the case for Seasonal customers, but not in general for year-round customers. BG noted that the electricity volumes of rural customers may be less than for year-round customers, but that in terms of fixed costs, the cost to connect is higher for rural customers.

John McGee noted that there are seasonal customers that are adjacent to year-round customers and feels that there may no longer be a justification for having Seasonal classes.

Ted Cowan noted that given the significance of the $110 million cost shift due to density weights, it is important to consider an option of how much a utility would have to pay to low density customers to exit the grid (self-generate). He suggested a capital solution should be considered in dealing with the rate differential and that the Rural and Remote Rate Protection (RRRP) program is outdated and may need to be adjusted. MV noted that such considerations at this time are premature and not within the scope of the study since the cost/density relationship is not yet fully known, which is the focus of the study. Ray Gee (HONI) pointed out that differences in rate classes also provide a signal to future consumers. Ian Malpass noted that this study is not intended to address RRRP and only considers the cost to serve. Ted Cowan reiterated that this study is an opportunity to look at all available options, including the RRRP. AP summarized the focus of the project and noted that rate design is another topic for HONI and the OEB to consider following the results of this study.

Peter Thompson sought clarification on the Slide 6 statement, "after correcting for other exogenous factors". BG clarified that there are other factors that have an impact on cost to serve. For example, costs that may be correlated with density, but are not specifically density related.

BG noted that there may be some qualitative discussion based on the results of the study that may address other concerns not specified in the current scope.

2.5 Slide 8

This slide illustrates the proposed methodology, which relies on two separate but complementary analyses (econometric and engineering). The first entails an econometric analysis that will look at the OM&A and OM&A and capital costs that HONI incurs across its operating areas (approximately 50 in total), in which there is variability in customer density. BG noted that the analysis will look at 'OM&A only' and will also look at 'OM&A and capital'. BG noted that previous econometric studies, in support of utility cost benchmarking, performed on behalf of the Ontario Energy Board have relied only on OM&A costs, as obtaining and normalizing data on capital costs is problematic when looking across utilities. BG also noted that while the quality of the underlying data has been a concern in previous OEB proceedings, the use of econometric techniques has generally been accepted. By using HONI-specific data for each of the operating areas, information is consistent and in greater depth, therefore less contentious regarding its accuracy.

The second part entails an engineering analysis, or a direct cost assignment study. This study will identify sample areas across HONI's distribution network which will vary in terms of customer density. Sample areas will also vary in terms of geography, undergrounding, and other characteristics. The study will then assign operating area level costs to sample areas and assess how costs differ with respect to customer density.

Bill Harper asked what specifically is being achieved in the engineering analysis and the use of smaller sample areas. BG responded that looking at smaller sample areas provides a broader range of densities than the average densities across the operating areas. Bill Harper also noted that distance from service centres could be another consideration in defining of density. He also asked if the density defined in the econometric study is used in the engineering study. MV noted that the engineering study is designed to be blind to the results of the econometric study and to the definitions of density in the econometric study. The engineering study focuses on the cost to serve different groups of customers (in terms of density) and that individual results will allow for independent conclusions. Henry Andre (HONI) noted that part of the feedback received from the 1st density study stakeholder session was that it would be useful to have more than one approach for looking at the density issue.

Bayu Kidane noted that relying on one analysis is not as reliable as two. He asked what happens if the two studies do not support each other? BG remarked that the econometric study can isolate specific impacts of customer density on cost. Engineering analysis, while it can normalize for other factors, is more aptly designed to determine the total cost difference in serving one group versus another (where density is a factor). They may not necessarily come to same conclusions; however they may provide different views or interpretations.

John McGee asked about the use of CAPEX in the studies. BG noted that CAPEX represents a plan on how the rate base will grow in subsequent years. BG also discussed asset intensity and the fact that you cannot simply add OM&A (OPEX) and CAPEX to derive total costs. Laurie McLorg also raised a similar question on this point. MV added that capital expenditure (CAPEX) is used and partially proportioned to deal with annual costs, because approximately 10% of CAPEX is depreciated annually.

Marion Fraser asked which study will isolate CAPEX already incurred. BG clarified that both studies will isolate these costs. Econometric analysis will look at O&M and the substitution effect of CAPEX (CAPEX today will reduce O&M tomorrow). In engineering analysis, there is less of a substitution effect; however asset intensity will be examined for costs already incurred.

2.6 Slide 9

This slide illustrates the major steps that will be followed in the econometric analysis. BG explained the four major steps involved in an econometric analysis.

- Identify a utility cost function that includes inputs, outputs, and operating characteristics;
- Compile a data set that incorporates the necessary input, output, and operating characteristics;
- Solve the model to minimize the error term in the cost function; and
- Interpret the estimated coefficients to reveal the sensitivity of costs to changes in the independent variables.

BG noted that operating areas within HONI's service territory provide a natural break in terms of how costs, customers, and assets are tracked. The goal is to minimize bias in the results by using these natural breaks and delineation points. The advantage in looking at intra-HONI costs versus inter-LDC costs is that no assumptions are needed on cost allocation since there are no differences in capitalization rules. Marion Fraser noted that the flip side is also true in that what is representative of averages does not necessarily reflect the extremes. BG agreed.

Peter Thompson referred to Jay Shepherd's email comment regarding the proposal not to use other Ontario LDCs cost data in the study. BG responded that the granularity in LDC cost data is insufficient for the purposes of the study and that differences in capitalization policies and treatment of shared services make a direct comparison difficult. Ted Cowan noted that for an LDC study the boundary problems are vastly more difficult and have great effects and agreed that the approach of the study will provide a more accurate picture. MV further elaborated on the fact that cross-subsidization within municipalities influences LDC cost data and makes its use problematic. Bill Harper noted that if you were to compare LDCs and HONI, you would not be able to determine if cost differences were due to density or differences in company efficiency. BG noted that the report will document the reasons why the use of cost and customer data from other Ontario LDCs is problematic when considering the impact of density on HONI's cost to serve.

Ted Cowan noted that it may be useful to take a look at data from other LDCs with different densities (if data is available). BG pointed out that the level of detail with HONI data is much greater than with the other LDCs data. For example HONI knows exactly the number of poles in each operating region. Peter Thompson asked if similar data from Slide 23 were available for the Kingston LDC. BG and Ray Gee noted that there will be differences in data and its availability.

Henry Andre suggested that comparing operating areas within HONI to other LDCs is more of benchmarking exercise than a study looking at density as sought by the Board.

2.7 Slide 10

This slide illustrates the major steps that will be taken in the engineering analysis. The steps include:

- Select operating areas and sample areas within them;
- Compile data on operating areas and sample areas ;
- Calculate assignment factors;
- Assign operating area and provincial level costs to sample areas;
- Calculate asset intensity for each sample area; and
- Evaluate the distribution of costs across the sample areas to indicate costs to serve different groups of customers.

There was no discussion on the content of this slide.

2.8 Slide 11

BG invited participants to offer comments or suggestions concerning the two methods being proposed. John McGee noted that operating areas are not set up as utilities. For example, feeders are intertwined. If a transformer station is within an operating area, this would cause problems. MV explained that there is good data granularity and connectivity data. It can be determined which feeders and portions of feeders go through which operating areas and sample areas. There is also connectivity of every feeder with every transformer station. Bill Harper asked if every operating area has its own service centre. BG responded yes, and noted that in some cases there are two service centers per operating area. MV also emphasized the power of GIS and that the physical location of all assets in system can be determined.

Peter Thompson suggested that in the final report, it would be helpful to note other potential methodologies that were considered and why there were rejected (e.g. using LDCs in comparing costs). MV agreed to consider this.

2.9 Slide 13

BG provided an overview of the econometric methodology. BG reiterated that the analysis will look at two separate cost functions (OM&A only and OM&A and capital). BG noted that scale (magnitude) is a major cost driver for HONI. Density is a measure of customer intensity. BG also went through a number of other factors that could be considered. BG noted that while increasing the number of data points (observations) will improve accuracy, as the number of characteristic variables increases, the accuracy of the function decreases. An appropriate balance needs to be established. John McGee suggested dropping the use of aerial customer density (customers per km^2). BG stated that the study will look at both aerial and linear density, while recognizing that the denominator used to determine aerial density will be an issue. MV remarked that it is important not to miss areas where there are physical assets, but there are no customers. Laurie McLorg inquired about data time series (use of multiple years of data). BG indicated that 3-5 years of data would be used and, if available and usable, more years of data will be utilized.

Bill Harper asked if there were any other measures of customer density that could be used (e.g. average distance from service center). BG and MV noted that the engineering analysis will look at these factors.

Bill Harper also noted that vegetation management is on a seven-year cycle and should be taken into account. BG responded that multiple years of vegetation data is available and will be properly accounted for and that it is recognized that vegetation management is a major cost driver.

Marion Fraser asked if distributed generation is being considered. BG indicated that this will not be considered as the window of data available is too small.

Neil Mather noted that cluster size is part of the existing definition and that boundary issues warrant particular attention. Ted Cowan noted that the econometric study will eliminate border issues with regards to clustering. MV agreed and indicated that the sample areas will not take into account cluster sizes, but rather representative densities. Bill Harper suggested using (binary) flags to represent certain break points in cluster size. He also remarked that this study may not determine if current rate class definitions are appropriate and suggested there may be a continuum of cluster sizes and questioned if there are any reasonable break points. On the issue of the appropriateness or otherwise of the current rate differential, BG described that what is intended is to compare current ratio of costs allocated to different customer classes against comparisons of the cost ratios between high-, medium-, and low-density sample areas. Bill Harper noted that the results may be difficult to interpret because any differences may be the result of density differences or may be simply the way density is defined.

Ted Cowan asked about the number of samples being considered. BG indicated that the econometric study will use all 50 operating areas and that the engineering analysis will select a number of sample areas from operating areas. MV remarked that based on some preliminary analysis, to acquire statistically meaningful results would require about 15 samples for each of high-, medium-, and low-density categories.

Ted asked if both planned and unplanned outages are addressed. BG confirmed that will be the case.

Elena Yampolsky asked if the econometric analysis will be able to use different definitions of density. BG responded yes, and that the study will present the best model (highest statistical significance or minimization of error term) but that the final report will document the other potential cost functions.

2.10 Slide 15

BG reviewed briefly this slide which illustrates HONI operating areas within the province. There were no comments on this slide.

2.11 Slide 16

BG reviewed briefly this slide which illustrates the density (both linear and aerial) diversity of operating areas. Ted Cowan asked if the HONI median value was known, but BG indicated that the median was not illustrated in the chart.

2.12 Slide 17

MV discussed the “bottom-up” approach (the use of unit costs and number of units to build up to a total cost) that was considered, but ultimately excluded from the proposed methodology. MV discussed the “top-down” approach which uses cost categories and assigns these costs to customer groups. To choose customer groups, sample areas will be selected which are representative of high-, medium-, and low-density customers, not necessarily customer groups based on the current rate classifications. Selection of sample areas is facilitated with GIS data. Both OM&A costs and CAPEX will be used in the study. Fixed asset related costs are apportioned based on an asset intensity analysis.

Approximately 80% of HONI’s costs will be assigned using a specific factor in the engineering analysis. The remaining 20% of costs are assigned based on ratio of the number of customers.

2.13 Slide 18

MV reviewed the definition of the various assignment factors. Several questions were asked on this slide, primarily to clarify the understanding of the various assignment factors. Laurie McLorg asked for additional detail on how the Asset Intensity Ratio (AIR) is calculated, the use of replacement costs, and the variability of installed costs throughout the province. MV clarified that installed costs do vary geographically and that this data is available and will be taken into account. Bill Harper requested further detail on what the AIR assignment factor is applied to. MV responded that it is used to assign certain CAPEX costs tracked at the operating area level to the sample areas (as is the case with the other assignment factors).

Neil Mather asked for additional detail on the characteristics of sample areas. MV provided a general description of the sample areas (e.g. range of 20-30 square kilometres with consistent density in each sample). MV also indicated that in order to achieve a reasonable confidence, 15 samples in each of the high-, medium-, and low-density categories (45 in total) would be required.

Ted Cowan asked if regression analysis would be used for the engineering analysis. MV clarified that regression will only be used in the econometric study. BG added that the econometric analysis does not incorporate cost data at a level lower than the operating area since a number of assumptions would have to be made to derive much of the data points. BG also noted that the engineering study will go into greater detail than the econometric study by looking at the sample areas within the operating areas. Ted Cowan indicated that he would provide written comments on his thoughts regarding statistical analysis.

2.14 Slide 19

MV discussed the next slide which looks at cost groupings at the provincial and operating area level, and the proposed assignment factors to be used in the engineering analysis. Laurie McLorg noted that PDR and CKM factors take into account distance, but not explicitly travel time. MV noted that travel time is a difficult item to deal with. For example, it is not known if each trouble call requires its own trip from the service center. MV also noted that delays occur even on high speed roads and that weather can reduce the speed of travel. In general, MV indicated that these travel time related factors are likely of second order magnitude relative to distance. Ray Gee expanded on the point and BG said that looking at distance traveled led to non-material changes from the use of "as the crow flies" distance.

Ted Cowan used an analogy of a horse and jockey to explain his thoughts on the importance of management experience at the operating area level and that management experience at the operating areas should be a factor to consider in the econometric analysis. BG indicated that this factor could potentially balance out when looking across all operating areas.

2.15 Slide 20

Elena Yampolsky asked how provincial level costs are apportioned to operating areas. BG noted that these costs are small ($23 million of provincial costs compared to $129 million directly assigned at the operating area level) and will be assigned to operating areas based on customer numbers, area, line km or "expanded" assignment factors. The costs are then allocated to the sample areas based on specific assignment factors.

Ted Cowan asked if line losses should be considered and density weighted. Henry Andre noted that delivery costs and rates are not impacted by losses and as such they are not density weighted. Losses apply to the commodity portion of the bill.

2.16 Slide 21

MV discussed the HONI databases described in this slide. There were no comments on this slide.

2.17 Slide 22

MV discussed the necessary characteristics of selected sample areas. There were no comments on this slide.

2.18 Slide 23

MV and BG elaborated on the abilities of the GIS. There were no comments on this slide.

2.19 Slide 24

MV summarized the two approaches (econometric and engineering) of the engagement. Qualitatively, costs incurred by high-, medium-, and low-density customers will be compared with tariffs based on the current rate classification.

3 Closing Remarks

AP remarked that there was good discussion regarding the study methodology and thanked participants for being engaged and that several good suggestions were heard. He asked all stakeholders if there were any further suggestions and whether the consultants could conclude that stakeholders were comfortable with the proposed methodology. Generally, there were no further comments, except for the following:

Bill Harper confirmed that the methodology is appropriate, but the team needs to be careful in defining the sample areas and work to get the analysis right in order to answer the following questions related to the last two questions on slide 4, namely:

- Whether the existing density-based rate classes and density weighting factor appropriately reflect costs incurred
- The appropriateness and feasibility of establishing alternate customer class definitions or delineation points

Ted Cowan reiterated his view that line losses should be density-weighted. AP remarked that the study needs to deliver on the scope defined by HONI which is based on satisfying the Board direction.

Susan Frank thanked participants for attending the session by taking time from their busy schedule and recognizing the importance of the subject matter discussed today. She commented on the wide ranging discussion but reminded participants that in as much as the comments received are valuable and appreciated, it is not possible to include them all as the scope of the study is limited and that the budget for the study has been set. She indicated that the consultants will weigh the input provided in today's discussion and what can be incorporated within the scope of their engagement.

Stakeholder Consultation
Rate Applications

CDM and Density Cost Allocation Studies in Support of Hydro One Rate Applications

AGENDA
March 22, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
8:30 a.m. – 12:30 p.m.

8:15 am	**Registration and Refreshments**	
8:30 am	Introductions and Review Agenda	Enza Cancilla, Manager, Public Affairs, Hydro One Networks
8:35 am	Welcome	Ian Malpass, Director, Regulatory Support, Hydro One Networks
8:40 am	Update on CDM Forecasting and OEB Directive	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
9:45 am	**BREAK**	
10:00 am	Overview and Update of Density Cost Allocation Study	Andy Poray, Facilitator, PowerNex, Ben Grunfeld, Presenter, London Economics
11:00 am	**BREAK**	
11:05 am	Overview and Update of Density Cost Allocation Study Cont'd	Andy Poray, Facilitator, PowerNex, Ben Grunfeld, Presenter, London Economics and Mark Vainberg, Presenter, PowerNex
12:25 pm	Next Steps and Closing Remarks	Ian Malpass
12:30 pm	**Adjourn**	

Attachment 1 – Participant List

Name	Affiliation
Bond, Reagan	Ontario Power Authority
Butany-DeSouza, Indy	Horizon Utilities
Cowan, Ted	Ontario Federation of Agriculture
Fraser, Marion	Canadian Energy Efficiency Alliance
Grice, Shelley	Association of Major Power Consumers in Ontario
Harper, Bill	Vulnerable Energy Consumers Coalition
Kidane, Bayu	Power Workers' Union
MacIntosh, David	Energy Probe
Mather, Neil	Ontario Energy Board
McGee John	Federation of Ontario Cottagers
McLorg, Laurie	Veridian Connections Inc.
Pasumaty, Dev	Electricity Distributors Association
Silk, Dana	Enviro Centre
Thompson, Peter	Canadian Manufacturers and Exporters
Yampolsky, Elena	Powerstream Inc.
Zajdeman, Marcie	Brookfield Asset Management
Zebrowski, Steve	Veridian Connections Inc.
HYDRO ONE	
Andre, Henry	Hydro One Networks, Inc.
But, Stanley	Hydro One Networks, Inc.
Cancilla, Enza	Hydro One Networks, Inc.
Frank, Susan	Hydro One Networks, Inc.
Gee, Raymond	Hydro One Networks, Inc.
Innis, Ian	Hydro One Networks, Inc.
Li, Clement	Hydro One Networks, Inc.
Malpass, Ian	Hydro One Networks, Inc.
Stadnyk, Alexandra	Hydro One Networks, Inc.
PRESENTERS	
Carew, Steven	London Economics International
Ford, Gary	PowerNex Associates, Inc.
Grunfeld, Ben	London Economics International
Vainberg, Mark	PowerNex Associates, Inc.
Poray, Andy	PowerNex Associates, Inc.

Attachment 2 – LEI/PNXA Presentation

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Hydro One Density Study (2011)

Stakeholder Presentation

Prepared by

London Economics International LLC

& PowerNex Associates, Inc.

March 22, 2011

Objective of stakeholder session

To determine whether stakeholders are in general agreement with the proposed methodology and to gather specific feedback

FACILITATOR	PRESENTERS
❑ **Andrew Poray**	❑ **Benjamin Grunfeld (LEI)** ➢ ben@londoneconomics.com ❑ **Mark Vainberg (PNXA)** ➢ markvainberg@pnxa.com

Plan of presentation

1 Introduction

Summary of Proposed Methodology

3 Details of Proposed Methodology

4 Additional Discussion & Questions

LEI and PNXA were engaged by HONI to evaluate the relationship between customer density and distribution service costs

- **The objectives of the engagement closely follow the Ontario Energy Board's (OEB's or the Board's) direction**
  - London Economics International LLC (LEI) and PowerNex Associates, Inc. (PNXA) are to evaluate the relationship between 'customer density' and distribution service costs
  - LEI and PNXA are to assess whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship
  - LEI and PNXA are to consider, qualitatively, the appropriateness and feasibility of establishing alternate customer class definitions

Under HONI's current methodology a higher proportion of costs are allocated to 'rural' classes, relative to the number of customers

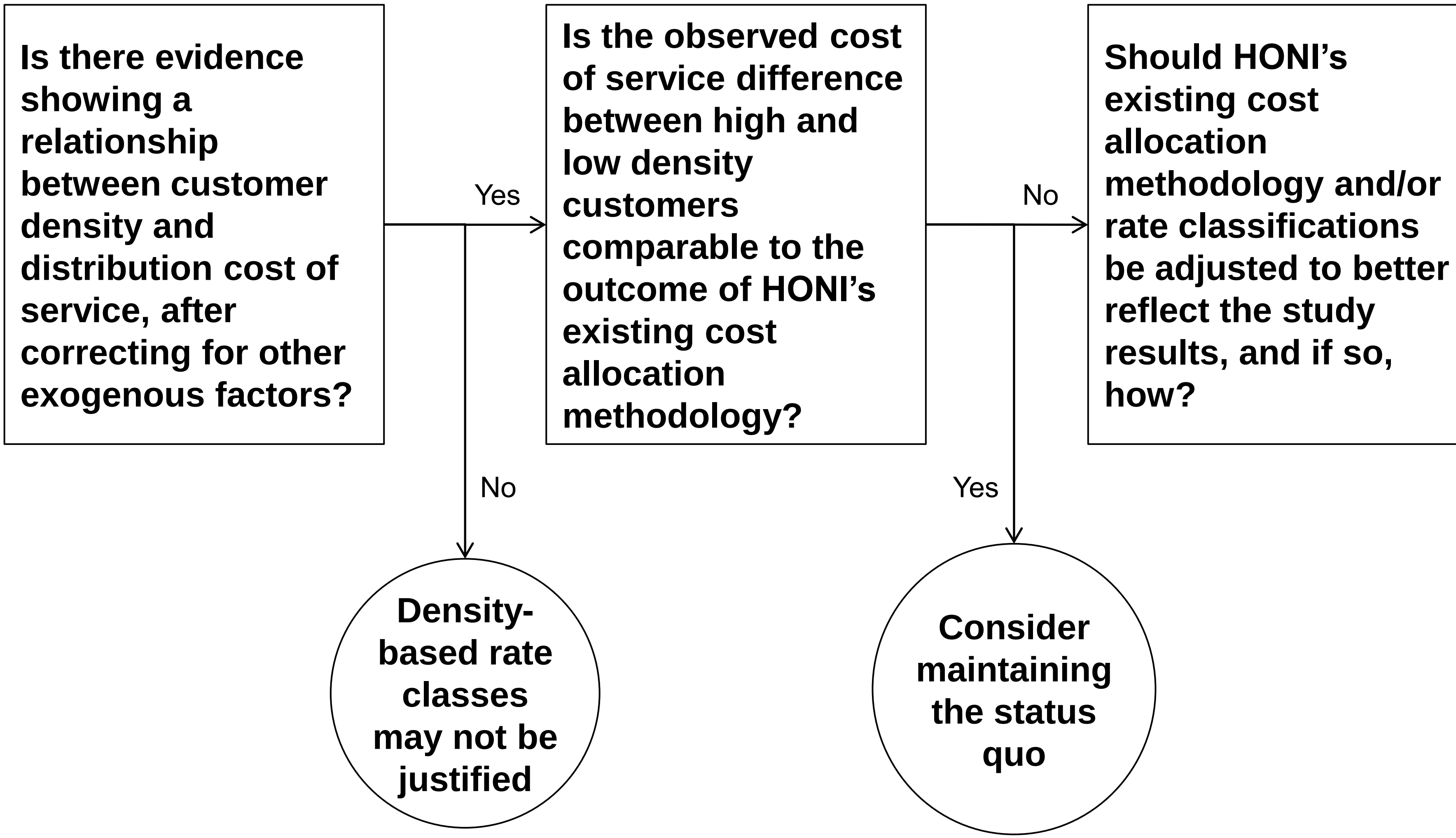
- **Current density weighting factors are based on the apportionment of lengths of distribution feeders and the net book value of transformers to individual sub-classes**

Illustrative Results of HONI Cost Allocation Model

	UR	R1	R2	Seasonal
w/ Density Weighting Factors ($M)	59.0	273.4	431.7	96.0
$ per customer per month	*35.0*	*55.2*	*98.0*	*51.0*
w/o Density Weighting Factors ($M)	106.6	336.8	334.8	84.1
$ per customer per month	*63.2*	*68.1*	*76.0*	*44.7*
Percent Increase/Decrease	81%	23%	-22%	-12%
	UGe	**GSe**	**UGd**	**GSd**
w/ Density Weighting Factors ($M)	8.7	121.5	12.6	128.8
$ per customer per month	*68.2*	*102.5*	*927.3*	*1,457.6*
w/o Density Weighting Factors ($M)	15.7	113.9	22.3	117.4
$ per customer per month	*123.8*	*96.1*	*1,641.4*	*1,328.6*
Percent Increase/Decrease	82%	-6%	77%	-9%

Source: HONI OEB Cost Allocation Model, 2010/2011 Distribution Rate Application

The study will consider a number of specific questions



Plan of presentation

1 Introduction

2 Summary of Proposed Methodology

3 Details of Proposed Methodology

4 Additional Discussion & Questions

The proposed methodology consists of two separate but complementary analyses

Econometric Analysis

- Econometric analysis using HONI operating area data (OM&A costs Only)
- ↓
- Econometric analysis using HONI operating area data (OM&A and capital costs)

Engineering Analysis

- Direct assignment of HONI annual OM&A and CAPEX cost data to sample areas
- ↓
- Asset intensity analysis of HONI capital costs in sample areas

- The proposed methodology takes into account feedback provided by stakeholders in the previous session and the OEB's direction

The econometric analysis will isolate the impact of customer density on HONI's distribution service costs

- The analysis will focus specifically on HONI's operating areas
- The econometric analysis will analyze the extent to which differences in cost across HONI's operating areas are explained by differences in customer density

Steps in Econometric Analysis

1. Identify a utility cost function that includes inputs, outputs, and operating characteristics
2. Compile a data set that incorporates the necessary input, output, and operating characteristic variables
3. Solve the model to minimize the error term in the cost function (i.e. such that the predicted values are very close to the actual values)
4. The estimated coefficients reveal the sensitivity of utility costs to changes in each of the independent variables

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The engineering analysis will identify the cost associated with serving specific groups of customers across HONI service territory

- **The focus is to identify how HONI's costs vary across groups of customers with different densities**
- **Will select and analyze sample areas across HONI's distribution service territory**
- **The analysis will directly assign HONI's costs to each sample area**
- **Will determine an average cost per customer within each sample area and a profile of average costs across HONI's service territory**
- **Analysis will incorporate the majority of HONI's costs**

Steps in Engineering Analysis

1. Select sample areas and corresponding operating areas
2. Compile data on sample areas and operating areas
3. Calculate assignment factors
4. Assign operating area and provincial level costs to sample areas
5. Calculate the asset intensity for each sample area
6. The distribution of costs across the sample areas is indicative of the cost to serve groups of customers

Question

Are there other considerations that should be included with these two approaches?

Plan of presentation

The econometric analysis will consider a number of distinct inputs, outputs, and operating characteristics

- **The analysis will look at two separate cost functions (OM&A only, and OM&A and capital)**
- **In most jurisdictions, including Ontario, data availability has restricted economists' ability to analyze utility cost functions that extend beyond OM&A costs**
  - Across HONI's operating areas the data limitations are less restrictive

Variables to Consider			
O&M Costs	CAPEX Costs	Asset Count and Type	Asset Value
Number and Type of Customers	Throughput (kWh)	Customer Density (linear/aerial)	Total km of Line
Physical Geography	Input Prices	Storm Data	Age of Assets

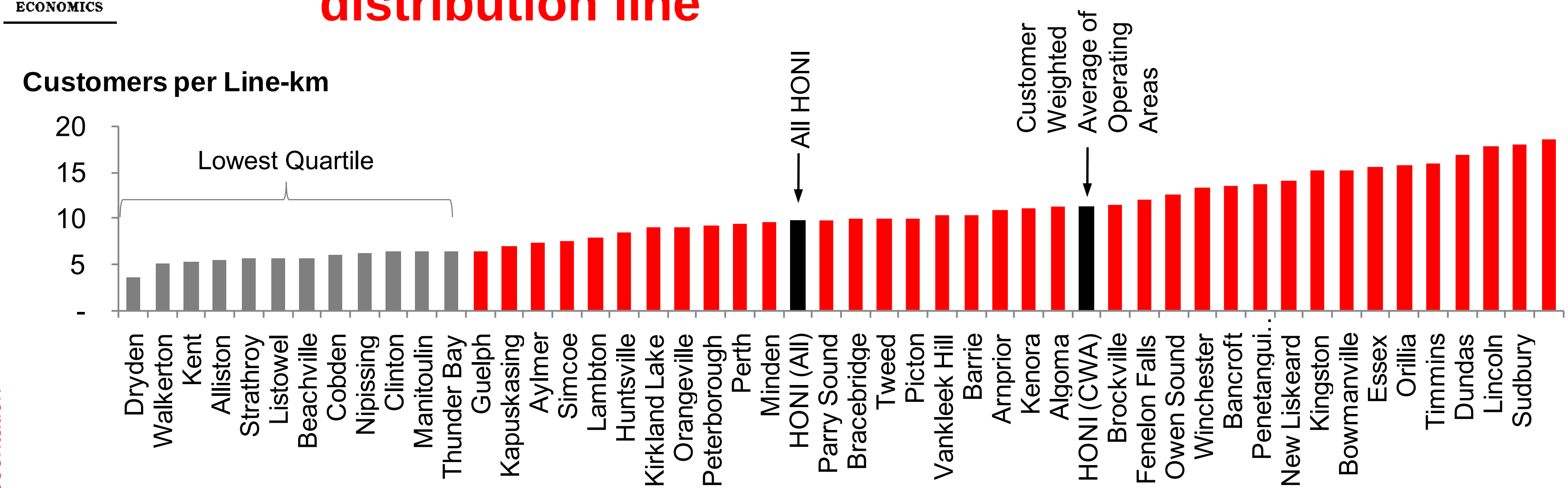
Question

Are there other variables (inputs, outputs, operating characteristics) that should be considered in the econometric analysis?

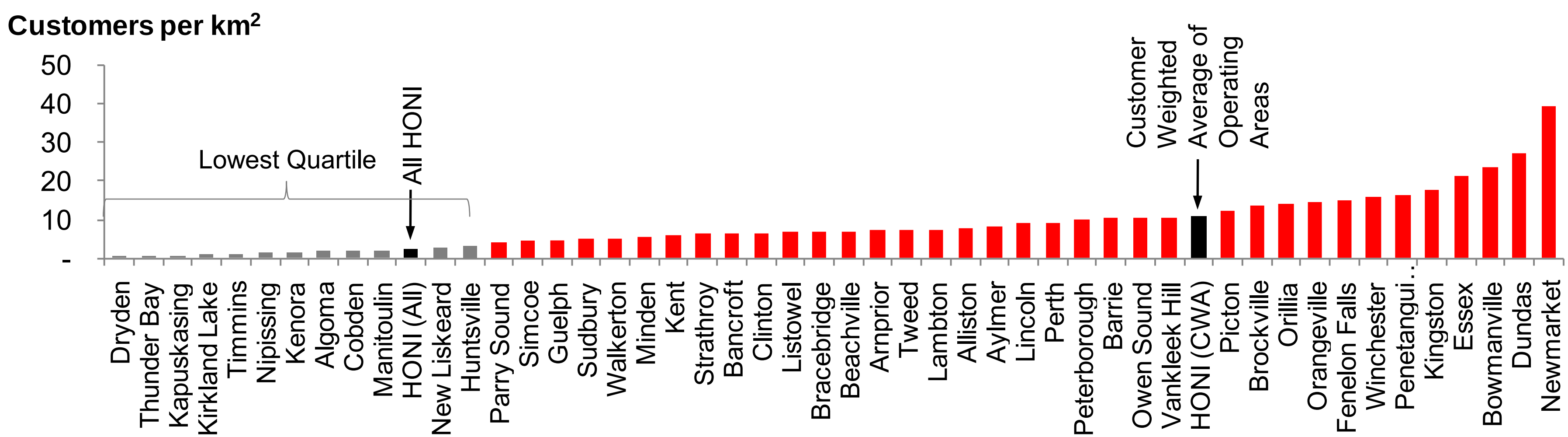
HONI's operating areas cover the entire province

Source: HONI

HONI's operating areas exhibit linear densities ranging from 3.6 to 18.6 customers per km of distribution line



- Likewise the operating areas exhibit aerial densities ranging from 0.1 to 39.2 customers per km^2



The engineering analysis will directly assign the majority of HONI's costs

- **The engineering analysis will utilize a "top-down" approach to assign costs**
  - The top-down approach starts with the highest level of costs, (i.e. the total aggregated OM&A and CAPEX related costs), and systematically works down through identifiable levels of cost tracking to the lowest practical level of cost tracking, at which point the costs are directly assigned to sample areas
- **The assignment of costs utilizes two complementary methods**
  - Annual OM&A and CAPEX are assigned using specific factors' that are selected and designed based on engineering and utility operation principles
  - Fixed asset related costs will be examined through an 'asset intensity' analysis
- **Approximately 80 percent of HONI's total revenue requirement will be assigned using specific factors and asset intensity**
  - The remaining 20 percent will be assigned in proportion to the number of customers

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A number of operational and customer/asset characteristics will be used to define the assignment factors

Range of Assignment Factors Being Considered

Assignment Factor	Full Name	Definition
AIR	Asset Intensity Ratio	Replacement cost of assets in sample area (SA) / replacement cost of assets in operating area (OA)
CR	Customer Ratio	Number of customers in sample area / total number of customers in OA
CKM	Customer-km Ratio	∑ of dist from customers in the SA to Service Center (SC) / ∑ of dist from customers in OA to SC
PDR	Pole Distance Ratio	∑ of distance from poles in SA to SC / ∑ of distance from poles in OA to SC
UGR	Underground Feeder Ratio	∑ UGR km in SA / ∑ UGR km in OA
IR	Interruptions Ratio	Total number of interuptions in SA / total number of interuptions in OA
IRWOS	Interruptions Ratio without Storms	Number of non-storm related interruptions in SA / number of non-storm related interruptions in OA
IR-Storm	Storm Interruptions Ratio	Number of storm related interruptions in SA / number of storm related interruptions in OA

Assignment factors will be applied to each cost category

- **Costs are generally tracked at one of three levels: provincial (e.g. engineering services); operating area (trouble calls); or feeder level (vegetation management)**
  - Assignment factors will be applied to operating area level costs
  - Provincial level costs will be apportioned to the operating areas and then assigned to sample areas using the assignment factors
  - Feeder level costs will be assigned based on the percentage of the feeder length located within a sample area

Proposed Assignment Factors for Major OM&A Work Programs

2010 Provincial Level Lines Sustainment OM&A
Eng Tech Serv - Major Impact Studies
PM: Recloser & Regulator Maintenance
Other Demand Lines DM P&P's
Field Collections, Special Invest
SQI Measures
Dx Lines Patrol
ERA
Meter Replacement Services
PM: Switch Maintenance (ABS & LBS)
Small External Demand Requests
Other Planned Lines DM P&P's
Misc Mtce
Eng/Tech Studies & ERA
Micro FIT & FIT Generation Connect
Not assigned
Data Collection
TOTAL: $23M

2010 Operating Area Lines Sustainment OM&A	Proposed AF
Trouble Calls	IRWOS x PDR
Cable Locates	UGR
Dx Lines Patrol	PDR
Field Meter Reading	CKM
Disconnect/Reconnect	CKM
Field Collections, Special Invest	CKM
CM: Defect Corrections	PDR
Small External Demand Requests	CKM
Meter Replacement Services	CKM
Other Planned Lines DM P&P's	PDR
Sentinel Light Maintenance	CKM
Not assigned	CR
Eng/Tech Studies & ERA	CR
Pole Transformer Inspect & Test	CKM
Other Demand Lines DM P&P's	PDR
Wood Pole Testing	PDR
TOTAL: $129M	

Note: Only provincial level categories with 2010 total cost greater than $250k are included

Question

Are there any additional factors that should be considered and/or should any of the proposed factors be adjusted or enhanced?

Data will be compiled from a number of HONI databases

- **HONI will assist in compiling the required data**

- **Four databases will be used:**
  - SAP Enterprise Resource Planning System
    - Annual operating, maintenance, and administrative (OM&A) expenses as well as annual capital expenditures (CAPEX) and information on fixed assets
  - Customer Information System (CIS)
    - Customer related information, including usage history, rate class, customer and service address, meter number, customer number, etc.
  - Geographic Information System (GIS)
    - Up-to-date information on the type and location of assets and customers across the entire network
  - Outage Response Management System (ORMS)
    - Trouble-call management system

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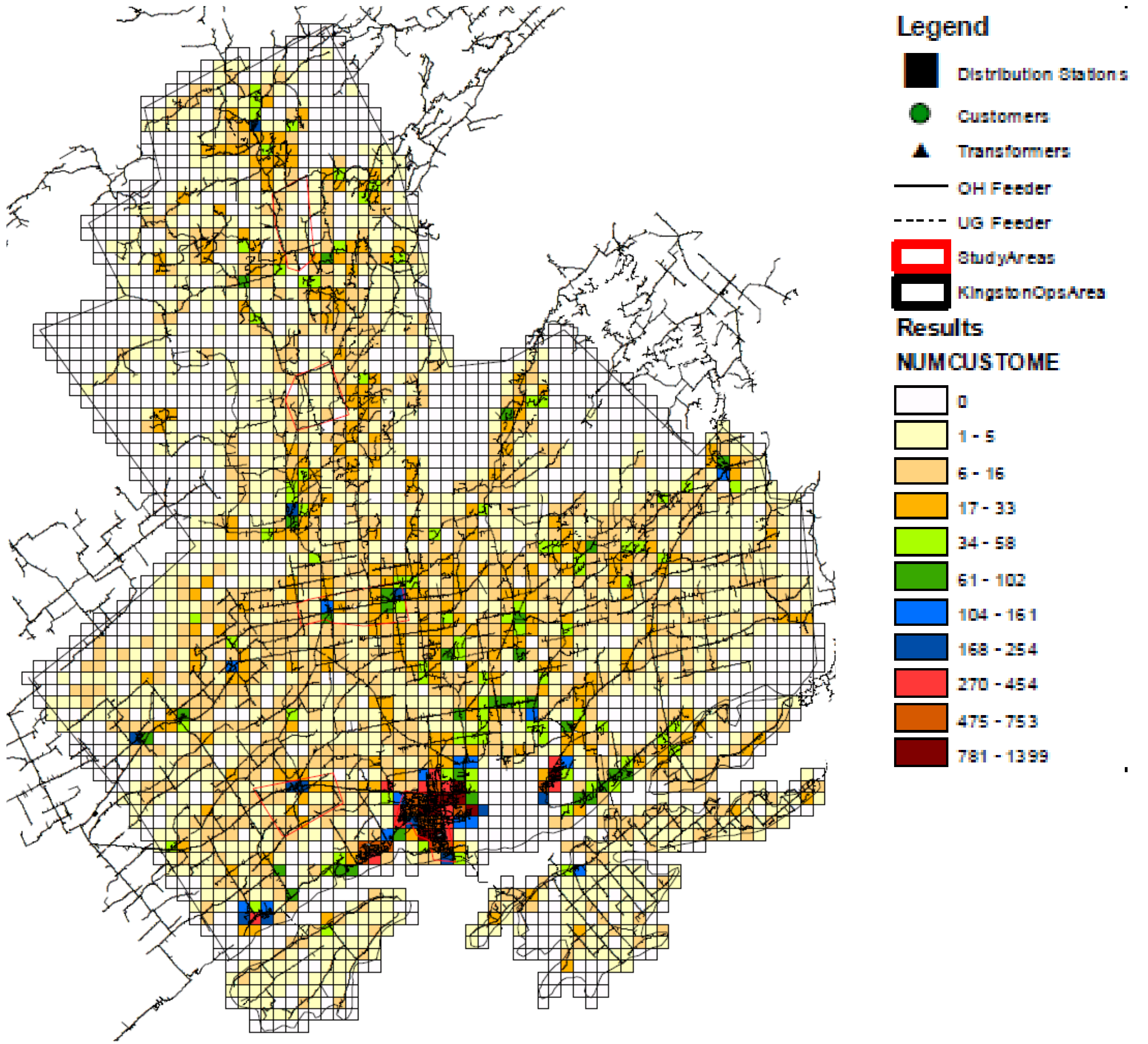
Selection and number of sample areas is critical in assuring statistical significance and confidence

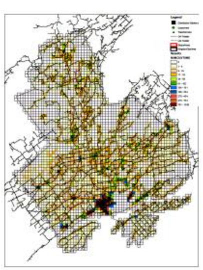
- **Sample areas will be selected such that they represent a range of high, medium, and low density customer groups**

- **The size and boundaries of sample areas will be chosen to ensure that they represent a material cross section of actual conditions, customers, and geography across HONI's network**

- **Data from a significant number of sample areas and operating areas is required to ensure statistical significance of conclusions**
  - LEI/PNXA estimate that at least 15 sample areas of each category will be required

Using HONI's GIS system, it is possible to create maps which illustrate the density of customers across the province





Specific conclusions can be made based on the results of econometric and engineering analyses

- **Results of the econometric analysis will:**
  - Identify to what extent differences in costs across HONI's operating areas are explained by differences in customer density
  - Determine whether one measure of customer density has better explanatory power than the other

- **Results of the engineering analysis will:**
  - Identify how HONI's costs vary across areas and groups of customers with high, medium, and low densities, taking into account other characteristics such as distance from service centers, type of assets in use, etc.
  - Allow for the comparison of the differences in directly assigned costs for high, medium, and low density sample areas to the differences in costs allocated to existing rate classes under HONI's current cost allocation methodology

Plan of presentation

Cornerstone Phase 4

CIS Replacement

Stakeholder Session

Wednesday June 29, 2011

1:30 – 4:00 p.m.

Victoria Room

Metropolitan Hotel

108 Chestnut Street, Toronto

TABLE OF CONTENTS

The presentation materials used in this session and background materials can be found at this link:
www.HydroOne.com/Regulatory Affairs

Participants

Stakeholders

David MacIntosh—Energy Probe
Harold Thiessen—Ontario Energy Board
Jack Hughes—Canadian Manufacturers and Exporters
Jake Brooks—Association of Power Producers of Ontario
Jay Shepherd—School Energy Coalition
Judy Simon—Low Income Energy Network
Julie Girvan—Consumers Council of Canada
Kim McKenzie—Power Workers' Union
Michelle Byck-Johnston – The Society of Energy Professionals
Roger Higgin—Vulnerable Energy Consumers Coalition
Shelly Grice—Association of Major Power Consumers of Ontario
Steve Zebrowski—Veridian Connections

Hydro One

Myles D'Arcey, Senior Vice President, Customer Operations—Hydro One
Mike Winters, Senior Vice President & CIO—Hydro One
Susan Frank, VP & Chief Regulatory Officer—Hydro One
Allan Cowan, Director, Transmission Applications Regulatory Affairs—Hydro One
Jeff Smith, Director, Project Management & Control—Hydro One
Vicki Power, Advisor, Regulatory Affairs—Hydro One
Alex Hamlyn, Assistant, Network Management Engineer—Hydro One

OPTIMUS|SBR

Bob Betts—OPTIMUS|SBR
Angela Boychuk—OPTIMUS|SBR
Miles Smit—OPTIMUS|SBR

START 1:35pm

1.0 Welcome by Allan Cowan, Director, Major Applications

Allan Cowan welcomed all participants to the Stakeholder update meeting on the CIS Replacement — Phase 4 of the Cornerstone project. He indicated that Hydro One will be advancing this project to 2012, ahead of the previous target of 2016. The presenters will provide a background on the Cornerstone project in general and the Customer Information System (CIS) in more detail, and will be including the reasons for advancing the system in-service date.

OPTIMUS |SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

2.0 Opening Remarks by Bob Betts, Facilitator

1:40pm

Bob Betts welcomed all participants, advising he is facilitating together with OPTIMUS | SBR. Bob introduced the OPTIMUS | SBR team - Angela Boychuk and Miles Smit - as note-takers.

In his presentation, Bob went over housekeeping items - meeting facilities, refreshments, planned break around 2:45pm, and the emergency instructions pointing out the exits in case of need. Note-taking will be done by OPTIMUS | SBR. The session will be recorded and the recordings destroyed once the notes are approved. Any comments made by individuals are done on behalf of the party they represent. Participants were advised if they want comments to be off the record to advise beforehand.

Bob reviewed the agenda for the meeting, indicating the ground rules. Presentations and notes will be posted on Hydro One's website. All participants were asked to introduce themselves for the record.

3.0 CIS Replacement, Cornerstone Phase 4 Update

1:50pm Cornerstone Update - Mike Winters, Senior Vice President, Information Technology

As an introduction to the Cornerstone Project, Mike Winters began the presentation with a review and explanation of Hydro One's overall IT strategy to rationalize applications and transform business processes through the implementation of commercial off-the-shelf (COTS) applications.

This strategy aims at reducing system components, supporting productivity improvement via the business benefits of adopting standard industry processes and best practices, and mitigating the risks associated with unsupported custom solutions.

The current customer service system (CSS) is expensive and cumbersome to maintain and update, being built on an IT platform from the mid-1990's, using Cobol coding and mainframe technology, requiring programming resources and skills that are becoming more scarce worldwide.

Currently, Hydro One relies on outsourced IT management. We would like to rely less on specialized and customized skills and tools, thereby reducing costs on outsourced premium services. Customer service and IT account for about 75% of the total Inergi outsourcing contracted by Hydro One.

Mike Winters provided a summary of the 4-phased Cornerstone project, which started in 2006.

- Phase 1 covered SAP's Enterprise Asset Management including asset management, work management, investment management, supply chain and some reporting. Phase 1 went live in Q2 2008.
- Phase 2 included Finance, HR, payroll, time reporting and business intelligence reporting. Phase 2 went live in Q3 2009.
- Phase 3 comprises a number of smaller scale projects, building on Phases 1 and 2 and includes such projects as supply chain optimization, advanced asset analytics, engineering design transformation, and business planning consolidation all of which are at various stages of completion and implementation.
- Phase 4 involves a CIS to replace the customized, legacy CSS built on discontinued platforms, to simplify interactions for customers and to drive efficiency and effectiveness through innovation and service delivery transformation.

The current CSS application runs on a totally dedicated IBM mainframe for both primary and backup systems, costing approximately $2-3million per year to maintain. By moving to a new SAP CIS, Hydro One can take out the mainframes and eliminate the associated upkeep costs.

Jay Shepherd asked when the predecessor system (CSS) was installed and went live. Mike indicated it was June 1998, using the Customer/1 platform. Andersen Consulting installed the system, but shortly got out of that line of business and re-aligned with the SAP customer care system.

Customer/1 was discontinued shortly after Hydro One went live unfortunately. So we were dependent upon the Customer/1 utility clients to make changes based on unique business needs. There was no standard installation or roadmap, so Hydro One could not ask for service or enhancement packs.

The new SAP system is widely used, and they have plans for service and enhancement service packs that Hydro One can readily install to improve business processes. The SAP system also allows easier integration with current systems (e.g., asset management, work management, supply chain, etc.), thereby reducing the linking software needed to tie systems together.

Mike reviewed a summary of the project process:

1) A Request for Information ("RFI") was issued with focus aimed at software vendors. Hydro One received responses from Oracle and SAP, the only vendors that could meet the requirements of a utility of Hydro One's size;
2) A Request for Proposals ("RFP") was issued for system integrators with 4 responses – 2 with Oracle and 2 with SAP;
3) A rigorous evaluation process resulted in a 3-month discovery phase with the lead integrator and to finalize scope, establish fixed price and benefits.

Jay Shepherd asked who the integration bidders were. Mike indicated that the bidders were HCL AXON (SAP), CGI (Oracle), Accenture (SAP) and PricewaterhouseCoopers (Oracle).

Roger Higgin asked what role "Inergi", Hydro One's current outsourced services provider, would play in the solution. Mike replied that Inergi has 2 roles:

1) Through Vertex (the call centre and customer care provider), Inergi will help define detailed requirements and functional design and assist with testing and implementation.
2) For application and infrastructure management, Inergi will ensure the platform stands up correctly, overseeing capability, load application, and testing.

Jay Shepherd asked if any of the system integrator bidders were related to Vertex or Inergi. Mike indicated that they were not related. Inergi is an affiliate of CapGemini and CapGemini chose not to bid.

HCL AXON was selected as system integrator and during the discovery phase Hydro One negotiated software costs for Itron and SAP. Hydro One used Gartner for third party expertise to discern the level of discount that could be expected from SAP. Hydro One was pleased to report that they were able to achieve an approximate 85% discount from SAP.

Roger Higgin asked if the discount was based on size. Mike answered that Gartner indicated a price band and based on various factors mainly size and current footprint of SAP. Roger opined that Hydro One's other SAP applications likely played a part in choosing SAP and without those applications, Hydro One would not have achieved such a large discount. Mike agreed.

The Board of Directors' approval was received in May 2011 with projected in-service date of late 2012.

The planning and the RFP process for the replacement of Outsourced Services will begin in earnest in Q3 or Q4 2012. The target issue date of the RFP is in early to mid 2013 to get to complete outsourced services switch out in early 2015.

Jay Shepherd asked about Vertex' involvement and requested information on the contracted vendor, contract start date, term and additional costs for the extension, and furthermore whether the extension contract made unit costs steeper.

Mike answered that the main contract is with Inergi as prime with a sub-contract to Vertex for customer care services. The original contract started in 2002 for a 10-year term and with a 3-year extension clause exercised to take Hydro One through 2015. In the extension, Hydro One was actually able to negotiate a steeper decline in cost through the various towers, with improved service levels.

Mike added that the RFI and RFP were used to assess the market, confirm fixed costs and set timelines proceeding to a work-back schedule allowing CIS to go live before having to negotiate new outsourcer contracts. Mike indicated it is not desirable to have a major customer information system change ongoing in a window when the outsourced customer service provider was distracted by other issues, such as bidding and being evaluated on a new outsourcing contract. From a simplicity standpoint, this approach with fewer activities occurring simultaneously also makes for more favourable negotiations on new outsourced services contracts related to customer service and IT once the extension expires: the more commercial off-the-shelf (COTS) applications Hydro One uses, the lower our costs should be.

Roger Higgin asked if the IT service is for on-going customer care services or system integration of software systems. Mike replied that the outsourcing contract deals with both customer services, including customer care, and IT. Specifically to IT services, the IT component involves infrastructure management for servers, data centre and end user computing devices, application management including making changes for regulatory purposes and end user support. For the customer care piece the expected benefits will be discussed later in the presentation.

Mike Winters reviewed the Cost-Benefit Summary for the Cornerstone Project and noted the net positive benefit associated with the project.

Roger Higgin requested clarification on the type of costs presented. Mike indicated that the costs broken out are the project implementation costs, primarily capital costs with some operations, maintenance and administrative costs. The benefits projected are over 7 years, including cost savings made possible by the system change.

Roger asked what presentation basis of cost and benefit numbers was used: are these capital costs, net present value of operating costs, or some other analysis? He emphasized that he would like to see the costs evaluated on a customer per customer basis in any future analysis.

Mike answered that the costs are project implementation costs for Phase 1 (mostly capital, and some operational and admin costs) and the benefits projected are gross over the 7 years, even though the benefits would run out to 10 or 15 years, if not more.

Roger indicated that he would want to see a “Benefit Realization Plan” including capitalized costs and benefits over reasonable system lifetime and also an understanding of costs on a per-customer or per-bill basis.

Jay Shepherd requested clarification on whether the benefits included tax benefits and the start point of the 7 year time span. Mike and Jeff replied that the projected benefits are gross and exclude tax benefits. The 7 year horizon starts from the implementation of each component.

Jay Shepherd asked why a 7 year horizon was used. Mike answered that it was chosen back in 2006 and asked the group their views on that since the operational life of the CIS would be much more than 7 years.

Julie Girvan suggested the benefits should be projected over the full expected life of system, but that going further out would be meaningless. The group generally agreed that the costs and benefits should be evaluated over a longer period, based on the life expectancy of the system. Mike Winters indicated that they certainly expect to use SAP for more than 7 years with major version upgrades to extend life of the various modules of SAP.

Judy Simon requested cost information on the upgrades. Mike replied that the costs were modelled into the cost structure for the CIS, but he would have to get the firm numbers for a follow-up discussion.

Jay Shepherd asked if the cost-benefit analysis presented for board of director approval is available for review.

Allan Cowan advised that it will be included in the filing.

Jay Shepherd then suggested leveraging the CIS template used by Enbridge, which facilitated cost review both by Enbridge and their ratepayers over the long term. Allan Cowan confirmed that Hydro One has seen the template and will be looking at how best to present their information, which will be included in the next application.

Mike indicated Hydro One has a rigorous process for tracking and reporting on benefits realization and ensuring they are attained and put into future investment plans and regulatory filings.

Jay Shepherd commented that the impact on costs, relative to the benefits to the ratepayer should be analyzed explicitly, which is a more focused examination compared to the general corporate cost to benefits analysis.

Shelley Grice asked if the costs include software licences and the change-out of the mainframe in the Phase 4 costs. Mike advised that the licences are included in the cost. The decommissioning of the mainframe is part of project cost and the run costs of $2-3M will be removed and reflected in future filings.

Jack Hughes asked if the $172M benefits include the 20% contingency that was built into the $180M cost for Phase 4. Mike confirmed that the 20% contingency is a project cost not reflected in the benefits value. If the project is completed without the 20% contingency the project benefits of $172M will not be impacted, but the project cost of $180M will.

Mike Winters then introduced Myles D'Arcey to present the vision and approach for the CIS build.

2:20 pm CIS Replacement Project – Miles D'Arcey, Senior Vice President, Customer Operations

Myles reviewed three key benefits of system replacement based on the proposed timeline in terms of meeting current needs, realizing immediate value and enabling a future customer vision.

1. The change addresses current needs – the current system was deployed in 1998 and is a custom-code system. Hydro One has invested over $200M in customized modifications since deployment and the CSS is now a stand-alone Hydro One system as a result of all of this customization. As an unsupported system, the risks attached are greater. The need to continue to customize the current system is driving ever increasing costs. There are costs and risks every time Hydro One "lifts the hood" or adds bolt-ons or required functionality to the system.

To this first point, Jay Shepherd asked what had changed in the plan to replace it for 2012 instead of the original date of 2016. Myles D'Arcey indicated generally that it relates to a "window of opportunity" that has opened and that this would be discussed in greater detail on Slide 16: Timeline for Replacement and Jay was satisfied to hear the full response at that time.

2. Customer value – the new system has greater capability and flexibility. SAP and Oracle have incorporated utility industry best practices. Additionally, Hydro One will be able to drive future enhancements to meet customer requirements. Hydro One looked at the costs of implementing the Ontario Clean Energy Benefit changes, and determined that a 70% cost savings would have been possible through SAP system. Thus, a lower total cost will be achieved, as code changes and revisions become easier.

To this second point, Jay Shepherd asked what the average spend is to make changes to the current system. Myles D'Arcey replied that in the last 12 months they have spent $10 - 12M. Recent years have averaged somewhere between $5-10M in revisions. One reason is that a rate change requires a code change in the current system, whereas SAP is table-driven.

Jack Hughes asked if the study was internal or external and whether the information would be included in future filings. Myles confirmed it was an internal study and it would be included in future filings.

Myles briefly reviewed the Benefits Evaluation information, providing examples of some benefits that would be achieved by the new CIS, including total cost of ownership by eliminating the mainframe computers, plus benefits, including best practices such as improving customer information retention when customers change accounts within the Hydro One territory.

Judy Simon was interested in knowing the detailed implementation strategy from now to 2015, especially concerning the order of components to be implemented. For example, given possible regulatory changes, could one component be completed sooner than others, such as low income customer benefit improvement?

Myles suggested that with a live date of Oct 2012, Hydro One will have the flexibility to implement change at lower cost. Hydro One will review the regulatory timeframe to ensure the best possible alignment.

Susan Frank indicated that the key challenge here is assessing any regulatory changes that need to be applied before the October 2012 timeframe: either changes would have to be built into both platforms at a high cost, or parties will need to consider whether delaying some changes would be more cost-effective.

Myles reviewed the link between the new CIS capabilities and the corporate objectives such as predictive analytics relating to the iCare component (prompting the agent to address the likely issue behind a call), achieving 90% overall customer satisfaction, deploying enhanced tools to improve employee engagement, conservation demand management (CDM), and driving productivity.

Jay Shepherd asked whether such new CIS capabilities are part of the initial solution or if they are add-ons requiring more spend. Myles advised that the examples given are included as part of the initial $180M solution.

Jay Shepherd asked if some proportion of cost is allocated to unregulated activities to cover the CDM component, given that regulated CDM programmes are largely OPA-mandated. Myles answered that there is no allocation for unregulated activities.

Myles summarized the point to say that CIS will provide a holistic view of a customer's bill, history, usage and conservation program enrolment. This will allow for meaningful discussions with the customer as they manage their bills, which is a need-to-have.

Discussion continued with Susan Frank, Jay Shepherd, Julie Girvan and Myles D'Arcey exploring the CDM program example, its purpose and cost allocations. Myles confirmed that the purpose of the CDM component is data mining and to use when servicing a customer.

Susan suggested that the issue could be summed up by saying that the new CIS would be able to generate data for subsequent use in marketing, enrolment and other applied efforts, which belong under CDM costs.

Myles agreed and said that the costs for CDM programming (enrolment, delivery and reporting) are *not* part of the project costs and would be identified and allocated later as required. Julie suggested that the costs of unregulated components be separated from regulated ones in the next filing. Jay added that a fair practice for allocation be used for regulated versus non-regulated elements, to ensure that components or portions of components used to support non-regulated benefits are identified separately and not included in ratepayer costs.

3. Customer vision – ensuring that the system has capability and flexibility for future changes and needs. Future needs are not currently built-in, but Hydro One is looking forward to ensure the system has the flexibility to grow in the ever changing environment. Hydro One is looking to see how they can use the investments already made to provide more data, functionality and capability for the customer's benefit.

To this third point, Mike Winters added that under the current system, it is cost-prohibitive to integrate with core applications such as time tracking, GIS, etc., to improve corporate productivity. The new system will allow better responsiveness to the field. Some less important add-ons have not been included in the current plan to ensure that the approximate ±2800 critical business requirements currently in the CIS implementation plan are completed effectively and efficiently.

Roger Higgin asked which classes of customer should be able to access account information online. Myles D'Arcey replied that with the current CSS system, customers can log onto My Account and will be included in the new CIS. The challenge is to meet the incremental functionality the customer will want going forward. The new system flexibility will provide for that. Customer consumption history is an example of that.

2:50pm Session Break

3:05pm

Myles D'Arcey continued with some information particularly relevant to electricity generation customers at slide 13 of his presentation. Primarily the new CIS will provide greater visibility of data, provide more information, and provide increased opportunities on how to present billing data (e.g., multiple accounts on one bill).

Jake Brooks asked what level of detail is expected. Myles indicated that as an example, today for microFIT, settlements are very simple, with start and end readings and the rate. However; in an outage situation, customers may question discrepancies between projected and actual revenue. With the new CIS, Hydro One will be better-equipped to provide data and analysis to answer these and many other questions in the future.

Julie Girvan asked if there would be charges for this kind of service. Myles responded there will be no incremental costs, because the requisite data is already available.

Jay Shepherd asked whether different reports could be created for customer groups at a future time. Myles replied that like TOU, these reports would be enhancements to the system and they would need to review what will be beneficial for the whole group. Mike Winters commented that any requirements not in the initial scope of the CIS could be considered later.

Susan Frank commented that it would be good to know what kind of functionality Jay was requesting since it may in fact be contained in the original CIS scope. It would be valuable information for Hydro One to assist in planning and budgeting to address those requirements in the future. Myles confirmed that the data will be available, but they need evaluate and understand what functionalities would be required to process the data.

Jay Shepherd indicated that it is important to know what functionalities are built into the current scope so that the costs of any add-ons could be properly accounted for.

Similarly Jake Brooks indicated that it is important to know what is going to be collected as part of the data set regardless of what is currently anticipated to be used for reporting. Myles provided an example, saying that FIT generators receive the same data info as interval-metered customer. For microFIT, customers will see initial and final reads, and rates applied. Jake commented that more information should perhaps be obtained to determine what data is most useful to present. Myles gave a further example of generation information, which must go through the MDM/R and be calculated separately, and which is not currently accessible to the customer.

The data collection and reporting issue is complex enough that it was agreed that it should be discussed further in subsequent consultations.

As an example of pressing concerns relevant to CIS, Myles reviewed some of the new customer requirements for electric vehicle and charging requirements, generation by solar and wind turbine, load management, etc. Currently Hydro One has about 5000 microFIT generators connected, with ±1000 in the hopper for rural Ontario, and another ±4000 by year end, as rooftop or standalone units.

Roger Higgin commented that generation is 1% of the customer base and queried the functionality and cost to be invested on applications versus overall $180M.

Myles countered that only today's requirements are built-in the $180M, and no incremental cost has been added for future functionality. For any additional functionality Hydro One would build a business case and request stakeholder input at that later time. This future information requirement was factored into the vision so that the system would have the future capability to provide those functionalities at reasonable cost. The information illustrated on slide 15 - The Customer of the Future, is not part of the current project.

Myles then reviewed the timeline for the project and addressed Jay Shepherd's earlier question about why the project timing was advanced. The CIS replacement process has a 3-year time frame. The outsourced call centre billing and IT support functions are essential to its successful implementation. Hydro One needs a window of stability with these outsourced functions to complete the CIS implementation in the outsourcing contract term ending 2015. When Hydro One had the opportunity to extend this outsourcing contract and create this period of stability, the window of opportunity opened.

Jay Shepherd asked when the outsourcing contract was extended. Myles replied it was as of May of 2010.

Roger Higgin asked if the advancement of phase 4 and the 3-year extension had been included in the prior regulatory filing. Myles indicated it was not in the filing. The extension was approved on its own merit.

Roger Higgin observed that Hydro One is going to pay an outsourced vendor $20M for participation, and asked whether discounts were negotiated, if benchmarking was done and how costs of billing and customer care could be reduced for the period of the outsourcing contract during which the new CIS was available for use.

Myles first responded that price reductions were built into the contract renewal or extension.

He went on to say that Hydro One has a framework for further potential future benefits, however, savings in this outsourcing arrangements could not be negotiated until real and achievable benefits could be validated when the new system was in place. Within the $172M in benefits, no billing or customer care cost reductions were built in within the 2 year window, as they still needed validation and contractual negotiations. Hydro One is in a strong position after validation to go back to the vendor for potential reductions.

Roger Higgin said that from a ratepayer perspective, he would like to see some benchmarking on customer care cost with other organizations using SAP. He suggested that it be included in Hydro One's regulatory agenda for the balance of the Inergi and Vertex contract.

Jay Shepherd commented that it should extend further, that if Hydro One is expecting future reductions in the next contract.

Myles invited Hydro One's Jeff Smith, Director, Project Management & Control, to present the slides summarizing the Project Cost.

Jeff indicated that about half of the project cost is the labour/implementation services, of which 2/3^{rds} is the integrator, HCL AXON. Jeff added that HCL AXON is number 1 in SAP integration in North America.

Through the discovery phase, Hydro One validated the integrator's assumptions, time and benefit. Mike Winters added that they tested the market by getting proposals from four bidders, and he added that HCL AXON was the lowest bidder.

Jeff went on to point out that HONI and Inergi make up another large portion of the labour cost. The business, IT and call centre services drive the project.

Jay Shepherd enquired about the resources and associated costs. Jeff confirmed that the project uses existing people seconded from other Hydro One roles which are back-filled with temporary staff. Jay asked to know the cost of back-fill staff. Hydro One indicated that they will need to review that and will provide the answer at the next session.

Susan Frank asked whether the concern was the possibility that the labour costs were in some way double-counted. She commented that those labour costs would remain where they are (e.g. ongoing

Settlements efforts), and the cost of moving their efforts into the CIS project would equal, or might exceed the current cost of their efforts.

Jay understood how these people would be used but just wanted to understand what the costs of the back-filling process would be. Jeff said he would determine that and report it at the next opportunity.

Jay Shepherd asked how the new capitalization rules under IFRS would change how interest and overhead are accounted. Susan Frank advised it is premature to be discussing this, but that the matter would be discussed at a later session.

Jeff continued the cost review to examine hardware costs. Hydro One already has existing infrastructure for SAP platforms that would be augmented. Software costs include SAP and Itron costs. Commissioning includes interface with third parties, (such as Symcor for printing bills).

Jay Shepherd asked whether the software costs were up front or an annual licence. Mike Winters responded that there is both an initial cost of $13.4M for first year, plus an annual maintenance expense which is typically 17-22%.

Jay Shepherd questioned if the commissioning cost includes any of Hydro One's internal cost. Jeff Smith said that it does not: it is for interfacing with third parties. This involves a combination of people – Inergi, and HCL AXON as the integrator, although some HONI staff will also be involved.

Jay Shepherd asked for a rough breakdown of interest and overhead numbers. Jeff replied these would be approximately $6M and $12M, respectively.

Jack Hughes asked how Hydro One determined a contingency of 20%, and whether it is projected that the contingency will be required. Mike Winters advised 20% is typical of major IT projects and consistent with Phase 1 and 2. Some of the contingency was used for each of Phases 1 and 2. If it is needed for Phase 4, HONI will follow its governance model. Mike emphasized that the Hydro One Board of Directors approved the 20% contingency on the basis that it could not be used without explicit Board of Directors review and approval.

Jack asked about the amount of contingency used in Phase 1 and 2. Mike indicated that not all the contingency was used for Phase 1 and 2 and the final numbers will be provided.

Susan Frank asked whether the 20% contingency would be included in the amount requested in the application. Mike confirmed that the contingency will be part of the application.

Jeff asked is anyone could think of any additional information that Hydro One should be providing with its application and there were no further requests. Allan Cowan added that the Enbridge template includes much of the required information requested, and it will be reviewed by Hydro One and populated with its data.

Jeff concluded the presentation with a brief review of the Green Energy example to illustrate the lower cost of the new system. The Green Energy Benefit project required 6600 hours to implement the changes. With the new system, the same changes would have taken an estimated 1600-2200 hours, a reduction of about 70%. Thus, there is a significant cost reduction in ongoing efforts to be had by implementing this new system.

Jeff turned the meeting back to Bob Betts for the final question and answer section.

Shelley Grice asked what other utility companies are using a similar SAP CIS. Myles D'Arcey replied that these include Texas Utilities, London Hydro, Blue Water Hydro, SaskPower, BC Hydro and others.

Jake Brooks asked how the Smart Grid Technology will tie into the new CIS system. Myles answered that the CIS is specific to customer system requirements and functionality, but there is potential for other uses of the data that can be collected. Jake suggested that over time there should be a second look to examine co-ordinated evolution and adaption of Smart Grid and CIS applications.

Myles responded that as enterprise systems come online, with dated information, the potential exists for additional and enhanced functionality linking into other Smart Grid options and other platforms like mobile functionality, geo-spatial functionality, GIS, etc. When it comes time for these enhancements a plan will be developed and presented to the stakeholders for input.

Another issue Jake Brooks suggested for consideration is the question of which kind of investments are utility investments, and which should be privately owned. Myles agreed that these questions would need to be considered.

4.0 Close

3:55pm

Allan Cowan concluded the meeting, advising that given the number of relevant questions and issues raised, another stakeholder session would likely be held in September to provide updates on studies and analysis for filing in fall, including further discussion about CIS, the compensation study underway with Mercer, the Density Study, CDM and Load Forecasting and an update on accounting issues and what the filing may look like.

Allan concluded the session by thanking the participants for their questions and information.

ADJOURN 4:00pm

APPENDICES

A. Summary

The CIS Replacement Project presentation was approached by way of an overview of Hydro One's governing IT strategy as well as the status of the 4-phase Cornerstone Initiative, of which the new Customer Information System (CIS) is the 4th phase.

Throughout the session, Stakeholders questioned Hydro One about issues of concern, including timing, costs, software and outsourcing options, benefits and functionalities that attach to CIS. Stakeholders also provided many valuable comments as input to the CIS implementation and regulatory presentation.

Detailed conversation focused on the due diligence conducted in Hydro One's decision-making process, particularly as it relates to:

1) The decision to advance the CIS implementation from 2016 to 2012;
2) The prices obtained from SAP, the integrator HCL AXON, and other contractors;
3) The pending expiry of the current outsourcing contract;
4) The co-ordination of CIS planning with other strategic initiatives;
5) Costs intended for inclusion in the next rate application.

Hydro One gave an account of the rationale, vision and approach for replacing the current, outmoded Customer Service System (CSS) with the more flexible SAP-based CIS, readily capable of handling foreseeable changes in accounting and reporting, as well as future customer and industry account management needs.

A number of direct questions helped identify issues which will require clarification or further research and analysis.

B. Key Action and Notable Items

1) Customer Care costs were requested to be reported also on the basis of cost per customer to facilitate comparisons with other SAP users.
2) Stakeholders indicated a desire to have a "Benefits Realization Plan" developed to track benefits included in the justification of this project.
3) Stakeholders generally agreed that benefits and costs should be analysed of the reasonable life of the CIS asset and not the 7 years currently used.
4) Stakeholders asked for more detail about the expected costs of future system upgrades.

5) Hydro One confirmed that they would file the report originally provided to their Board of Directors that outlined the cost/benefit analysis for the board's consideration of the CIS replacement project.

6) Hydro One has noted and will consult the template completed by Enbridge Gas Distribution as part of its CIS stakeholder consultation process.

7) Ratepayers requested that the cost/benefit analysis provide some focus on the impact to ratepayers, both in costs they will bear and benefits they will receive.

8) Hydro One will provide more detail about the 20% contingency included in the $180M project cost, including:

   a) Cornerstone Phase 1 and 2 contingency budget usage;

   b) How the 20% contingency will be presented for regulatory consideration.

   c) How the contingency will be managed if the project comes in below budget or above budget.

9) Stakeholders generally understood the drivers and the rationale for advancing the timing of the CIS Replacement Project

10) Stakeholders asked that Hydro One file the internal report that analyzed the costs of making changes to the existing CSS.

11) Stakeholders indicated an interest in seeing a detailed implementation plan. The specific interest here was to consider whether certain benefits (such as those to low income consumers) could be realized as early as possible.

12) Hydro One indicated a need to discuss the approach to requested changes to their systems during the transition to a new CIS, to understand and evaluated the costs/benefits of having to make changes twice versus only once.

13) There was general interest in ensuring that the costs of the CIS Replacement and any changes made to the current design are reasonably evaluated and allocated to customer class to ensure that cross subsidization is kept to a minimum.

14) Parties were generally interested in gaining a better understanding of the functionalities that will be built into the new CIS

15) Similar to the previous item, there was interest in further information about the kind of data that will be collected by the new system, so that stakeholders could consider future uses of that data.

16) Stakeholders were interested in learning more about the customer care arrangements with Inergi/Vertex and how they compare to other utilities cost/benefits in delivering the same services. The interest relates both to the recent extension arrangements and the understanding that all will want to consider new arrangements when the current contracts expire.

17) Hydro One agreed to provide more details about the estimated costs for the use of Hydro One personnel in the project, with specific interest in the costs of back-filling for seconded staff.

18) A follow-up CIS Replacement project stakeholder session will be planned for the fall.

C. Meeting Agenda

Stakeholder Consultation

hydro one

Cornerstone Phase 4 CIS Replacement Stakeholder Session in Support of Hydro One Rate Applications

AGENDA
June 29, 2011
Metropolitan Hotel
108 Chestnut Street, Toronto
Upper Level
Victoria Room
1:30 p.m. – 4:00 p.m.

1:30 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:40 p.m.	Introductions	Bob Betts, Facilitator, OPTIMUS | SBR
1:50 p.m.	Overview of Cornerstone Project	Mike Winters, Senior Vice President, Information Technology, Hydro One
2:00 p.m.	Overview of Cornerstone Phase 4 CIs Replacement	Myles D'Arcey, Senior Vice President, Customer Operations, Hydro One
2:45 p.m.	**BREAK**	
3:00 p.m.	Q&A	Mike Winters, Myles D'Arcey and Bob Betts
3:45 p.m.	Nest Steps and Closing Remarks	Bob Betts / Allan Cowan
4:00 p.m.	**Adjourn**	

Stakeholder Consultation Notes

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

OPTIMUS | SBR
REGULATORY SERVICES

Table of Contents

The presentation materials used in this session and background materials can be found at this link:

http://www.HydroOne.com/RegulatoryAffairs

1. Participants

Stakeholders

- Emerissa Babin – Ontario Power Generation
- Michelle Byck Johnston – Society
- Ted Cowan – Ontario Federation of Agriculture
- Vincent DeRose (Conference Call) – Canadian Manufacturers and Exporters
- Phil Dubeski – Toronto Hydro Electric System
- Julie Girvan – Consumers Council of Canada
- Shelley Grice – Association of Major Power Consumers in Ontario
- Bill Harper – Vulnerable Energy Consumers Coalition
- Bayo Kidane – Power Workers' Union
- David MacIntosh – Energy Probe
- Neil Mather – Ontario Energy Board
- John McGee (Conference Call) – Federation of Ontario Cottagers
- Patrick McMahon (Conference Call) –Union Gas
- David Poch (Conference Call) – Green Energy Coalition
- James Sobota (Conference Call) – Pollution Probe
- Harold Theissen – Ontario Energy Board
- Mark Vainberg – PowerNex
- Steve Zebrowski (Conference Call) – Veridian Connections Inc.

Hydro One

- Carm Altomare – Hydro One
- Henry Andre – Hydro One
- Richard Bertolo – Hydro One
- Allan Cowan – Hydro One
- Susan Frank – Hydro One
- Ellen Holden – Hydro One
- Sabrin Lila – Hydro One
- Ian Malpass – Hydro One
- Keith McDonell – Hydro One
- Tony Miles – Hydro One
- Vicki Power – Hydro One
- Anne-Marie Reilly – Hydro One
- Nikita Sheth – Hydro One

Presenters

- Brad Bowness – Hydro One
- Stan But – Hydro One
- Ben Grunfeld – London Economics
- Mark Hirschey – Oliver Wyman
- Iain Morris – Mercer
  Marvin Reyes – Mercer
- Kristi Robins – Mercer

OPTIMUS | SBR

- Bob Betts – OPTIMUS | SBR
- Tara Murphy – OPTIMUS | SBR
- Miles Smit – OPTIMUS | SBR

2. Welcome by Allan Cowan, Director, Major Applications, Hydro One Networks

START 1:00pm

Allan Cowan welcomed all participants to the Stakeholder Consultation meeting. He outlined the Agenda for the day and listed the topics that would be discussed:

1. Conservation and Demand Management (CDM) Study
2. Density Cost Allocation Study
3. Compensation Benchmarking Study
4. Productivity Measures
5. An update on the CIS Replacement – Phase 4 of the Cornerstone project.

OPTIMUS | SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

3. Opening Remarks by Bob Betts, Facilitator

1:07pm

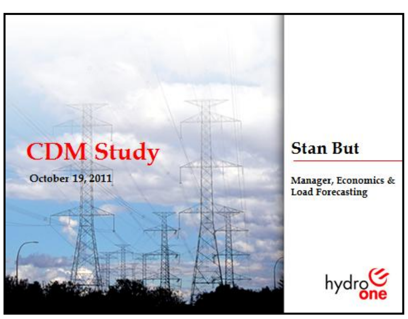
Bob Betts welcomed all participants, and advised that he is facilitating together with OPTIMUS | SBR. Bob introduced the OPTIMUS | SBR team (Tara Murphy and Miles Smit) as note-takers.

Bob began his presentation with several housekeeping items and pointed out the emergency exits. Bob stated that notes will be taken during the meeting and that the meeting and discussions will be recorded. He noted the recordings will be destroyed once the notes are produced. Any comments made will be attributed to the individual and the party they represent. Participants were instructed if they want comments to be off the record to advise beforehand.

Bob asked all attendees to introduce themselves, stating name and company for the record. He reviewed the agenda, asked for phones to be turned off and mentioned that questions are welcome as they arise. The presentations and notes generated will be published on the Hydro One website.

CDM Study, Stan But, Manager, Economics and Load Forecasting, Hydro One Networks

1:15pm



View or download a copy of the CDM Study Presentation

Stan But began his presentation with an explanation of why the CDM study was undertaken. The CDM study was directed by the Ontario Energy Board (OEB), which requested more details about the CDM analysis and particularly credible load forecasts and greater accuracy than has previously been available. The Board accepted Hydro One's CDM estimates used in load forecast, but directed Hydro One to work with the Ontario Power Authority (OPA) to devise a robust, effective and accurate means of measuring expected impacts of CDM programs. Stan reviewed the recommendations made by stakeholders in the February 2011 and March 2011 consultations:

1. Conduct the CDM study in-house;
2. Review the CDM categories and methodologies used to incorporate CDM impacts into load forecasts by utilities in other jurisdictions;
3. Comprehensive CDM categories that are trackable;
4. Work closely with the OPA to better define and measure CDM impacts for use in load forecasting;
5. Present CDM impacts by sector and customer rate class.

Stan But stated that Hydro One had acknowledged and addressed each of these recommendations.

The study had two main objectives. The first was to develop a robust methodology to forecast CDM impacts and the second was to develop a methodology to incorporate the CDM impacts into Hydro One's load forecast.

The study findings included a Literature Review involving British Columbia, New York, California (as per stakeholder recommendation) and other major utilities in North America with CDM experience. Web-search and personal communication were used to gather data. Hydro One did a comparison study of load forecast methodologies commonly used by other utilities that incorporate CDM impacts into their forecasts. Finally Hydro One has been in close communication with OPA staff over the last 6 months to incorporate this information into CDM estimates.

A Load Forecast Survey was sent to approximately 100 organizations in North America, and 41 responses were received. The Literature Review and Survey provided a roster of well-defined and comprehensive CDM categories:

- Programs initiated by the utility;
- Programs initiated by other organizations;
- Building codes and standards;
- Rate structures;
- Increased conservation effect.

The Load Forecast Survey identified three commonly used models to incorporate CDM impacts in load forecasting.

- Method 1 forecasts using the actual load (without CDM adjustments);
- Method 2 forecasts CDM impacts as a variable on the right-hand side of the econometric equation;
- Method 3 adds historical CDM impacts to the actual load and forecasts forward.

Hydro One reviewed the advantages and challenges associated with each method. On the basis of the review results, Hydro One has adopted Method 3.

Susan Frank asked which method the OPA uses. Stan replied that the OPA also uses Method 3.

Ted Cowan asked for clarification on the main differences with respect to weaknesses in Methods 2 and 3. Ted suggested Method 2 regresses data weakly and Method 3 might contain errors in the CDM data. Stan clarified that both Methods 2 and 3 require CDM estimates for the history, so the same CDM data is used in each Method. Method 2 has a potential to create bias in the forecast because of collinearity issues. Method 3 adds the CDM impact to the actual load, which avoids multiplying any such collinearity issues.

Ted agreed that Method 3 addresses the issue of including CDM impact, but posited that they are still embedded in the initial regression estimates you are subtracting from. He asked if it was correct to say that all of the Methods have some weaknesses, but in Method 3 the weakness is confined to the CDM data. Stan clarified that the same CDM data is used in both models, but the data is used differently to achieve unbiased coefficients in Method 3. Ted responded that Method 2 and 3 do not differ substantially with respect to error.

Stan acknowledged that there are pros and cons for each method. Methods 1 and 2 are not invalid or incorrect, but they have characteristics that make them less suitable for Hydro One's specific requirements.

Ted Cowan asked for Stan's intuitive relative assessment of the merits of the three methods. Stan replied that Hydro One has determined that in light of the Board's request for a robust, accurate model, Method 3 is the most appropriate choice.

Ted inquired about the experience Hydro One has using Method 3. Stan replied that Hydro One has effectively been using Method 3 for a number of years and is comfortable with its performance.

Stan proceeded to review the study findings. He identified that the categories in the Hydro One CDM forecast that are aligned with the OPA Policy Instruments referring to Slide 10 of his presentation:

- Programs, further broken down in Hydro One's forecast into Hydro One/OPA programs, and other influences;
- Codes & Standards;
- Rate Structure.

Hydro One uses a number of methods and models to track customer actions. Accordingly, Hydro One has deployed an additional category called the Increased Conservation Effect. This was defined as customer behaviour to conserve energy that is not influenced by Hydro One, OPA, and other non-government programs.

Ted Cowan asked, regarding rate structure, whether separate analysis is conducted for customers that are demand billed versus customers that are volumetrically billed. He suggested there is a larger price effect for those who are demand billed.

Stan replied that for rate structure Hydro One uses CDM impact data from the OPA, and assumes that it covers all customer data. Ted agreed that all customers are considered, but asked whether demand- and volumetrically-billed customers are distinctly identified in the data. He asked specifically about the possible case of a farmer on demand billing, who conserves more than a farmer on volumetric billing.

Stan said that the impact is accounted for in each billing scenario. Ted inquired whether it is possible to tell the two billing methods apart, because there is a difference in savings for each billing type. Stan did not believe that the data from the OPA breaks the information down by rate class. Ted suggested that the savings differences by volumetric versus demand rate classes should be identified in the data.

John McGee asked whether Hydro One had any figures on the demand reduction from the Smart Meter program. Stan replied that for 2013 the Smart Meter (Time of Use) impact for all Hydro One customers was approximately 20 megawatts.

Bill Harper sought clarification on the definition of the term "Increased Conservation Effect" used by Hydro One. He asked whether the Increased Conservation Effect was equivalent to, or aligned with, the OPA's definition of Natural Conservation. Stan replied that they are not the same effect. Hydro One's definition of the Increased Conservation Effect is any non-program savings above or beyond Natural Conservation.

Bill observed that electricity rates are increasing by 10% and inflation is up 2%. He wondered whether the Increased Conservation Effect could be a response to customer awareness of higher bills. Stan replied that the Increased Conservation Effect does not capture increases due to inflation. Inflation and increases in price are captured in Natural Conservation. Historically, electricity prices trend upward, and a conservation response is expected without additional interventions.

Bill used a potential example to highlight his point: a customer who looks at an energy-efficient product (without a program coupon) and wants to be environmentally conscious is counted in the Increased Conservation Effect if he purchases the product. Alternatively, if the customer chooses to buy the product because of his increased electricity bill it is considered Natural Conservation. Bill suggested that the process to determine whether conservation is increased or natural is unclear, given the definition of the Increased Conservation Effect.

Stan But proceeded to describe the steps taken to understand and align with the savings assumptions used in the OPA's current conservation forecast.

The preliminary CDM impacts for 2011-2013 shown on his Slide 12 include the following categories:

- Impacts of Hydro One and OPA Programs;
- Other Influences;
- Codes and Standards.

Each of these categories is expected to drive increased energy savings over time. Stan did not present data for Rate Structure impacts on energy because the Rate Structure data from the OPA only includes Peak Savings while his Slide focused on energy savings. The fifth category, Increased Conservation Effects was based on data from 2010 actual, forecasting no increase in this category 2011 to 2013.

Stan indicated that the flat-line Increased Conservation Effect forecast was a conservative stop-gap, and Hydro One will need the actual 2011 data to make accurate forecasts beyond 2010.

Bill Harper asked for clarification on the forecasted data. He asked whether the forecast for 2013 was based on impacts from 2013 only or if it was the cumulative impact of programs implemented in 2011, 2012 and 2013. Stan clarified that the forecasted data represents the cumulative impact for that year. Therefore the difference between two years is the incremental change from year to year.

Susan Frank asked for an explanation of how the forecasts for Increased Conservation Effect were calculated. Stan replied that multiple analyses were used to determine the forecasted impact of Increased Conservation Effect. The first was using the hourly load of Hydro One in 2002-2010 to run econometric analysis. The impact of economy and weather were removed and the remaining impact was the total impact attributed to the CDM.

In addition to the econometric analysis, the customer information system was utilized. In this approach the annual energy consumption for over 500,000 residential customers with consistent information was analyzed. The result of this method showed consistent savings with the econometric approach. The final method was using tracking surveys where customers listed their own actions towards conservation and actions driven by programs. This information confirmed that there is an Increased Conservation Impact from the customer.

Julie Girvan questioned the validity of using customer surveys to calculate the increased conservation impact. Stan explained that the large survey (approximately 6000 customers) results were not used in the calculation, but rather to confirm the econometric results.

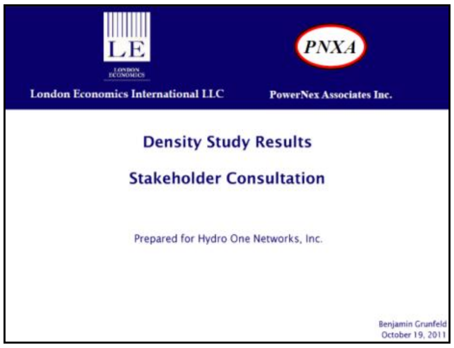
Stan provided a summary of the CDM impact study and indicated that the study was nearing completion, incorporating stakeholders' recommendations and meeting the Board's Directive.

Susan Frank added that the OPA did not evaluate the impact of the Increased Conservation Effect and asked whether other organizations are using this category. Stan replied that the results of a web survey showed that 1 in 5 utilities in the survey use a category that captures Increased Conservation Impact. He mentioned that the state of California is making a major effort to monitor customer behaviour, actions and savings associated with market transformation. This is an emerging issue that is being studied in other organizations.

Julie Girvan asked if the Green Energy Benefit (a 10% discount) would cause customers to reduce conservation efforts. Stan replied that the 10% reduction in the customer's bills is a new feature that was not captured in the analysis. Ben Grunfeld, of London Economics stated that the Green Energy Benefit came out around the same time as HST, which increased customer bills. Therefore from an incremental impact on customer bills the HST likely neutralizes the Green Energy Benefit reduction for the next 3 to 5 years.

4. Density Cost Allocation Study, Ben Grunfeld, London Economics

2:05pm



View or download a copy of the [Density Cost Allocation Study Presentation]

Ben reviewed the mandate given to London Economics and PNXA to evaluate the relationship between customer density and distribution service costs. He outlined that the study was initiated in response to a request from the OEB. The study also assessed whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship. A third object was to consider the appropriateness and feasibility of establishing alternate customer class definitions. The third objective, while covered in the report would not be discussed to a large degree in this afternoon's presentation.

Referring to his Slide 5, a two phased approach was used to perform the study, with the first phase being the Methodology Development and the second and current phase Methodology Implementation. The methodology consisted of two complementary analyses: Econometric study of the operating areas, and Direct Cost Assignment of smaller sample areas. Both analyses considered operating, maintenance and administrative costs and proxies for capital costs.

Julie Girvan asked for the definition of an operating area. Ben explained that an operating area is a geographic area within the province. Each operating area has service centres used to respond to customer calls, manage maintenance, operating programs and capital programs for that area. Julie asked whether the operating areas are the areas listed on the Hydro One website during an outage. Ben confirmed this is correct.

Ben continued with an outline of the econometric methodology. Using his Slide 6, he explained that the functional form of the econometric model was chosen based on theory and prior experience and pointed out that this is the form used by the OEB. The equation takes into account that an increase in customers from 5 to 500 for a given area equals an increase in cost that is not uniform. Determining the cost function was an iterative process, where a number of different specifications were tested. The five independent variables included in the final model were:

1. Customer Density (stakeholder recommendation);
2. Number of customers;
3. The square of the number of customers
4. Energy density;
5. A time or trend variable.

Ben explained that a representative cross section of sample areas was selected. A total of 11 operating areas were utilized for the direct cost assignment. The study included 62 samples areas, 24 low-density, 22 medium-density and 16 high-density from the 11 operating areas. The sample area selection guidelines included:

- Similar areas, approximately 20 km^2;

- 100 – 200 customers for low density;
- 700 – 1200 customers for medium density; and
- Over 2000 customers for high density.

Ben indicated that the costs were directly assigned to the individual sample areas. These cost groups include:

- Lines and Stations (operations, maintenance and administrative costs);
- Vegetation Management;
- Asset Intensity (representing capital costs in the ground).

Julie asked about other assets not in the ground, specifically the cost of trucks. Ben stated that fixed capital costs are not dealt with in this direct cost assignment study, but maintenance costs for assets such as trucks would be included in maintenance costs for the sample area. Ben stated that the proportion of Hydro One assets reflected by vehicles is small compared to other assets in the ground.

Henry Andre confirmed that the costs associated with trucks and other vehicles are included in maintenance costs. He continued with an example, stating pole replacement costs include the cost of equipment required to replace the pole. Maintenance costs include labour and equipment.

Bill Harper asked if lines and stations administrative and maintenance costs were combined, given that distance is important for lines and not important for stations. Ben Grunfeld replied that they are dealt with separately. He added that station costs were allocated based on the number of distribution stations within an operating area and the way they are used to serve load in the sample areas.

Ben introduced the results portion of his presentation and asked for questions before he continued.

Julie asked if the approach that Ben is undertaking has been used in other jurisdictions. Ben replied that based on the research there are no jurisdictions that have yet used this level of detail to analyze the effects of customer density. He added that he has seen econometric models to predict utility costs that incorporate customer density, as considerations. The OEB cost allocation model uses a number of allocation factors to distribute cost to classes of customers. [This general approach, of allocating costs based on factors, is similar to the one used in the direct cost assignment analysis. However, the direct cost assignment analysis looked at smaller samples of customers that vary with respect to density, as opposed to a complete class - Note this clarification is subsequent to the session.] Ben reiterated that the specific approach of looking at customer density is a unique feature.

Ben continued with the results, stating that the econometric analysis indicates a negative or inverse relationship between cost and customer density. Four distinct models were analyzed, and all showed a negative relationship:

1. OM&A (operations, maintenance and administration) using circuit km.
2. OM&A using sq. km.
3. OM&A and a capital proxy using circuit km.
4. OM&A and a capital proxy using sq. km.

Bill asked for clarification about the final bullet point on Slide 12 suggesting that it should say that according to the fourth model, a fivefold increase in customer density should correlate to a 150 percent decrease in cost per customer. Ben confirmed this is correct.

Julie asked if Ben was referring to cost per customer. Ben replied that it is the measure of total cost. He stated that the number of customers is included in the econometric model so they normalized for scale already. He explained with an example, where if the number of customers stayed the same, but the density increased there would be a decrease in cost.

Ted Cowan sought to clarify Ben's example, asking if, in the hypothetical case of two different 20km^2 areas, one with 200 customers and one with 1000 (i.e., a fivefold difference in density) the one with 200 customers would see a 50% decrease in cost.

Ben replied that the relationship depends on the number of customers being constant. Ben used an example of a 20km^2 area and a 4km^2 area with the same number of customers. In that case, the cost would be different: it would cost 50% more for the less dense area. This is the conclusion from the econometric model, and is also consistent with direct cost assignment approach.

Ben elaborated other results, indicating that the individual sample area results revealed a sharp decline in cost per customer as density increases.

Ted asked whether most of the variation is found in areas under 100 customers per km^2 and whether most of the variation within that range is under 20 customers per km^2. This would mean that most of the variation is in low and very low density. Ben replied that Ted's interpretation was correct.

Bill asked how a density of 100 customers per km^2 would translate into customers per line km. Ben answered that in Hydro One's rate class definition, a cluster of 100 customers and 20 customers per line km. Subsequent to the session Henry Andre confirmed that the definition is based on 15 customers per line km.

Ben stated that the sample mean averages in the study were distinct, and confirmed the negative relationship. He concluded that the two independent analyses confirm that the average cost to serve Hydro One customers increases as the customer density decreases with 99% statistical confidence.

Bill asked if graphs were created for customer per km of line. Ben answered that those graphs were generated and that they could be found in the final report.

Beginning to address the second study objective whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship, Ben discussed customer density as a differentiator on his Slide 15.

He noted four elements of Hydro One's existing rate class structure to consider:

1. Type of rate classes;
2. Number of rate classes;
3. Demarcation points;
4. The cost of allocation factors.

The first significant point he made was that from a rate making perspective, based on “cost causality”, it is reasonable to differentiate between customer classes by customer density.

The results also support having different classes, two general service customer classes makes sense, given a much smaller number of customers. There was no strong evidence to support a change in demarcation points.

Vince DeRose asked whether the report would look at municipal or regional boundaries. Ben answered that the report will look at both and the pros and cons associated with each approach.

Julie Girvan asked how Hydro One currently demarcates the rate classes. Ben answered that an urban rate (UR) class is an area that has 3000 customers total and has a line density of more than 60. The Medium density grouping applies to residential (R1 and R2) and has over 100 customers and a line density of 15, the Low density for residential is the remainder. For general service, there is a distinction between urban and non-urban customers.

Ben explained that the last objective was to consider cost allocation factors, of which there are two elements: non-density factors and the density-weighting factors. The study compared the overall results of the cost allocation model to the direct cost assignment analysis. The concern was with the ratio of per customer assigned costs, not the total magnitude. Ben concluded that the existing allocation may not capture the actual differences between the mean costs of serving year-round residential customers in areas with varying customer densities.

Slide 17 of the presentation package showed the comparison between the allocation factors for Hydro One’s current UR, R1 and R2 classes, 1.0, 1.6 and 1.7 respectively and the allocation factors resulting from the study for HD, MD and LD, 1.0, 1.7 and 3.8 respectively. While the relative comparison did reflect a higher cost per customer in a low density area versus a higher density area, it indicated that the higher costs are not being fully allocated.

The study further found that:

- The average customer density of the Seasonal rate class falls between that of the R1 and R2 classes;
- The average customer density of the urban GS classes, UGe and UGd, is similar to that of the UR class; and
- The average customer density of the non-urban GS classes, GSe and GSd, falls between that of the R1 and R2 classes.

Ben reviewed the three study objectives. He concluded that two independent analyses demonstrated that there is a statistically significant negative or inverse relationship between customer density and costs. The study demonstrated that cost to serve customers of different densities is different, supporting the use of density-differentiated rate classes.

Existing allocation and weighting factors may not capture the magnitude of the difference in costs to serve customers of varying density. The report addressed alternative customer class definitions, including structures based on municipal boundaries or regional rates. Ben concluded that a move to such a design is a long-term decision that should be considered in the context of a broader provincial dialogue that looks at rate design across all of the LDCs. Overall, the study's objectives have been accomplished.

Julie asked for a restatement of the conclusion for seasonal classes. Ben replied that the costs currently assigned to seasonal customers is 1.5 times the per customer cost assignment of urban class, this is in line with R1. The average density for seasonal customers is between the R1 and R2 rate classes, this indicates under representation of the costs to serve those customers. A similar conclusion applies for the non-urban general service classes.

Susan Frank pointed out that the results of this extremely comprehensive and expensive study cannot be ignored when it comes to rate design. Susan asked Henry Andre how Hydro One would implement the impact of the study.

Henry replied that the results of the study were very compelling. Some changes to Hydro One's cost allocation and rate design to incorporate the study are warranted, and Hydro One expects to respond appropriately.

The extent of the impact on cost allocation and rate design is dependent on how the results are used within the cost allocation model. Hydro One has not explored this in detail, but they did look at the last cost allocation model that was filed with the 2008 Distribution Application. Based on that model and trying to incorporate the findings of the 2011 study, there could be an approximate decrease of 10-15% in UR rates, and a potential approximate increase of 2-3% for the R2 rate classes.

The increase in R2 rates matching the decrease in UR is less because the volume of revenue collected from the R2 class is significantly more. In terms of delivery rates, delivery is approximately 1/3 of the transmission bill, so one could divide the estimated increase/decrease by 3 in terms of overall bill impacts. These are mere approximations because Hydro One has not utilized the new cost allocation model for the upcoming application. The findings are based on the previous cost allocation.

Julie Girvan asked how the study might help Hydro One rethink the seasonal rate design. Julie stated that she would like Hydro One to be more proactive on the issues involving seasonal rate design. Henry Andre replied that in terms of cost allocation, the study suggests that the cost of serving seasonal customers as a class (made up of low density and higher density area customers), would likely fall between R1 and R2. The current cost allocation model is pinning them at the R1 level (Subsequent to the meeting Hydro One clarified "pinning them at the R1 level" reflects that under the current cost allocation model the total costs per customer allocated to the Seasonal and R1 rate classes are about the same).

Henry stated that he took the point about issues with seasonal rate design. He continued that Hydro One could look at shift between fixed and variable costs, a concern raised by some seasonal customers. The study suggests that the cost to serve seasonal customers is higher because they are made up of medium- and <u>low-density</u> (corrected subsequent to the meeting from high-density) areas.

Bill Harper asked if Hydro One should alter the definition of the class or if they should change the way density is considered in the cost allocation model. Bill noted that the study suggested a change in allocation factors rather than changing the class definitions. Bill asked if Hydro One is considering choosing a different allocation factor other than customer per km to weigh customers by class.

Henry replied that Bill was correct. There is no current plan to change the definition of the rate classes. Hydro One does plan to look at the cost allocation model to consider whether the density weightings need to be changed. He raised the question of whether something else needs to be done at the bottom line to shift costs.

Bill asked if Hydro One was considering a new parameter for the model. Bill noted that changing the bottom line outcome of the model would be a new approach to cost allocation overall.

Henry clarified that his preference would be use the current approach, but the study suggests there is not enough differentiation between the weighting factors. The differentiation between the weighting factors would need to be increased so that more is allocated to the R2 class versus the UR class.

Bill observed that the study analysis assumes relationships between costs and density. He noted that the differences in the end are a function of what allocation factors were used in the analysis and stated that the differences need to be reflected in the Hydro One model. Henry agreed.

Ted Cowan mentioned that the general service class is the life-blood of the economy in rural Ontario. He asked if there would be any changes to their rates based on the results of this study. Henry replied that the ratios for the general service class were not covered in Ben's presentation, but they will be included in the final report. He noted that if the general service class is a blend of R1 and R2 then there might be some adjustments made. Ted asked if this would likely mean a 2% adjustment. Henry replied that he has not made any calculations on the general service class and so could not speculate, but there would be a higher differential based on the results.

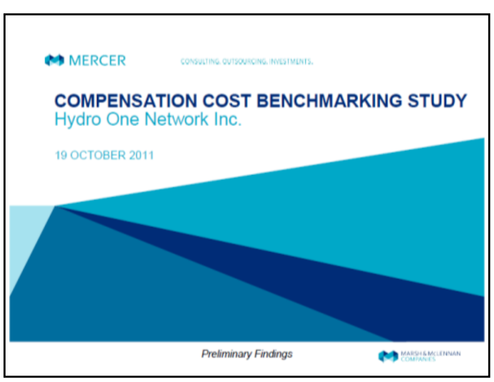
Julie asked when Hydro One was planning to file the Distribution Rate Case. Susan Frank replied that the original filing date was after the November Board Meeting, but the filing would be delayed until the shareholder could review it, including the new Minister.

The filling date will likely be early 2012, after the budget is reviewed by the shareholder.

Vince asked if that meant the Distribution Rate and Transmission Cases would be occurring simultaneously. Susan replied that this is a likely possibility.

5. Compensation Benchmarking Study, Iain Morris, Mercer

3:27pm



View or download a copy of the [Compensation Cost Benchmarking Study Presentation]

Iain Morris began by discussing the input from the May 2011 Stakeholder consultation. He stated that consideration was given to all Stakeholder requests, but not all could be met in professional opinion of the consultant. For example, Mercer did include a comparison to market average compensation.

Iain described how benchmark positions were determined and listed the positions used. He noted two differences between the previous study and this one resulting from insufficient available data to benchmark the Field Service Coordinator and the Tree Trimmer positions. In the case of Tree Trimmers, this position is most likely been contracted out at other utilities, and the Field Service Coordinator responsibilities were generally distributed throughout other job classes.

Mercer's experience also suggests that there needs to be a balance in the number of benchmark positions to use because often survey participants will avoid surveys that involve too many benchmark jobs; the 34 they chose is a reasonable balance. He reviewed the chosen jobs in the three Groups, Non-Represented, Professionals and Power Workers contained on Slide 5 of his presentation. He indicated that these jobs collectively represent approximately 3300 employees, or approximately 49% of Hydro One's workforce. In Mercer's opinion this is a representative sample size.

Iain described the process for determining the peer group. A similar approach to the 2008 study was taken. The process met the key objective of creating a single peer group to assess total compensation costs for the entire set of benchmark jobs. The list of peer groups was provided on Slide 7, and Iain noted that because some organizations such as Bruce Power and Bell Canada opted out of the study in 2011 and while others were added, this would generally be expected to result in an overall lower survey group benchmark in the marketplace than the 2008 study.

Iain gave a description of elements included in Total Compensation which are the same as 2008. It focuses on items that can be monetized including:

- base wages or salaries;
- short-term incentives;
- long-term incentives;
- insured benefits;
- retirement plans.

Definitions and methodology for determining total compensation were discussed and outlined on Slides 9 &10. Slide 10 provided the definitions of average and P50 (the 50th percentile). Mercer took this opportunity to once again state their reasoning for relying on the P50 or the middle point in a distribution of data rather than the average, including its representation of the compensation paid by the employer in the middle of the group and its stability coming from ignoring occasional skewing associated with extremely high and extremely low compensation circumstances of some survey participants. However, as requested by some stakeholders, Mercer has provided comparisons on the market mean in addition to the market median.

Iain reviewed the preliminary results in Slides 11 to 17. He compared the Hydro One median to the Market median changes from 2008 to 2011. Overall, there has been a decrease in Hydro One's total compensation from 2008, but total compensation remains above the Market median on a weighted average basis. Iain noted that wage and salary freezes and turnover costs affect total compensation; and further that many organizations in the study have also been attempting to reduce compensation costs just as Hydro One has. Iain explained that as a result of these efforts to reduce labour costs (in addition to the lower survey group benchmark noted earlier), the market median is effectively lower in 2011 than it would have been in 2008; but despite this lower market median, Hydro One has been more effective in reducing its relative compensation costs and has moved closer to the market median in 2011. He also explained that greater variation between 2008 and 2011 may be driven by low job incumbency and high turnover, where a more junior staff replaces a higher paid senior staff that retired.

Michelle Byck-Johnston asked for a definition of the Engineer F position. Keith McDonnell responded that it is a management-level compensation job (typically a band 7, and may contain some band 6 positions). Iain added that Engineers A to F are generic titles that line up with the Professional Engineers Ontario (PEO) categories.

Shelley Grice asked about the “not applicable sign” beside positions such as Senior Legal Counsel and Area Superintendent. Iain replied that the not applicable sign denotes that insufficient data exists, for example when a statistically significant sample is not available. In the case of Senior Legal Counsel, Area Superintendent, Business Analyst A, Electrical Apprentice and Lines Apprentice, “not applicable” is indicated because these jobs were not included in the 2008 study.

Bill Harper asked for clarification on the weighted averages. He asked if the 2008 weighted average was based on the incumbents in 2008 or those in 2011. Iain replied that the 2008 weighted average was based on incumbents in 2008. Bill asked what the effect of positions that had insufficient data in either year had on the weighted averages. Iain replied that overall the effect was insignificant.

Iain presented the comparison of overall - total compensation averages on Slide 17 as was requested by some stakeholders. He stated that the results did not differ greatly from the overall total compensation median results found on Slide 11. The only strong difference was in the Power Workers category.

Bill asked why the average compensation was not listed for 2008. Iain replied that the average was not calculated in 2008.

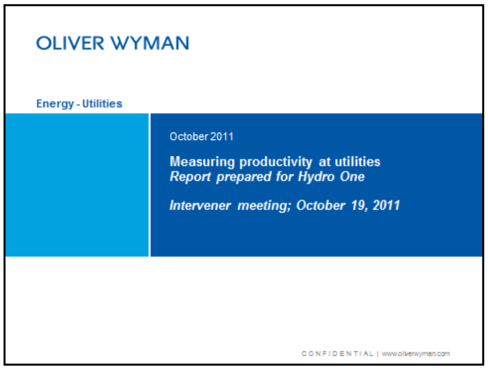
Iain concluded that overall the Hydro One relative position is still above market, but its efforts at controlling compensation costs have been effective and Hydro One has moved closer to market median since the 2008 study.

Ted Cowan asked if there was a comparison for turnover rates. He also asked for information on productivity, asserting that one needs to analyze what is produced to determine value of the compensation package.

Iain replied that he could not comment on turnover as it was not part of the study and was not a metric used in the past. Iain further stated that productivity was also not a factor in the study and mentioned that Mark Hirschey would discuss productivity in his presentation.

Productivity Study, Mark Hirschey, Oliver Wyman

4:05pm



View or download a copy of the Productivity Study Presentation

Mark began by stating that the 2008 Productivity study made reference to compensation and could be consulted to answer at least in part Ted Cowan's question about mapping to compensation.

Mark provided the background to the study, explaining that the Board had requested Hydro One to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate hearing. He noted that the Board will expect any compensation increases to be matched with demonstrated productivity gains.

Mark outlined the approach on his Slide 3, where internal and external research was conducted to build a set of recommendations around how Hydro One could measure productivity. He explained the research, recommendation and implementation processes. The results of the study suggest a number of metrics as candidates to measure productivity.

The primary research used US and Canadian regulators. The majority of regulators examined measured total costs and service quality metrics instead of productivity metrics. In fact, no commission or regulator was found to routinely measure productivity directly.

A survey of utilities' productivity was administered to understand which metrics could be collected internally. The list of survey recipients and respondents was presented on Slide 8. The findings from the productivity survey noted a wide disparity in internal performance measurement. Common metrics for cost, productivity and service quality were collected if measured by at least two utilities. The criteria for choosing a set of metrics was highly dependent on the individual business needs.

Moving to his Slide 15 he focused on the process of selecting appropriate metrics to be used. The first step to determining the area to measure was understanding the breakdown of spend on resources (principally being labour), included in transmission and distribution capital and operations, administrative and maintenance costs. In Slide 16, Mark gave examples including distribution operations, maintenance and administrative project metrics. The eight largest distribution projects had suitable metrics to measure. Most metrics were inconsistent over time and could not be measured.

Ted Cowan stated that he had trouble accepting the inconsistencies attributed to trouble calls over time. He suggested that each trouble call is distinct, but at the end of each year they could be useful as aggregated information and compared from year to year. He used an example of unique ER visits at a hospital, which provide cumulative metrics that can be measured.

Mark granted that Ted's comment was correct, when looking at trouble calls over a multi-annual basis, since weather added a large variability from year to year. Ted noted that there are other examples of projects that can be measured over 5 years. Mark replied that it is difficult to utilize the results on an assessment made every 5 years. Mark acknowledged that further study could possibly establish some consistencies in multi-year trouble call data to allow that to be used in some way as a productivity metric.

Slide 17 listed the twenty-five productivity metrics that have been recommended and which account for approximately 22% of the total project costs. Unfortunately, the last quarter of these metrics reflect no more than 0.2% of Total Costs individually, but they are all associated with discrete units of work that can be measured.

Michelle Byck Johnston noted that there were two metrics titled "Cost per km of line cleared", and asked for clarification regarding their differences. Mark explained that one referred to line clearing in transmission new-build projects and the other in distribution maintenance.

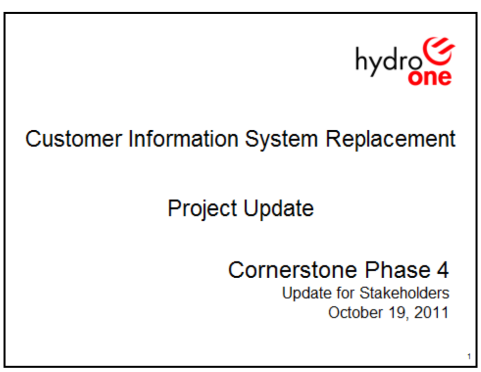
The idea was for Hydro One to choose a set of metrics that could be measured and managed over a shorter time period to begin to effect positive changes. Hydro One will require a detailed plan to develop a set of productivity metrics that are integrated and aligned with the overall corporate scorecard and direction.

Julie Girvan asked if the metrics were strictly field-related, because administration work is contracted out.

Mark replied that the metrics have fully-loaded overhead costs showing savings in overhead over time. Julie asked why there were no service quality indicators or typical customer service measures in the metrics. Mark replied that the customer service measures are associated with a contracted work force; Hydro One's work force aligns with field service measures.

6. Cornerstone Phase 4 CIS Replacement, Brad Bowness, Hydro One

4:37pm



View or download a copy of the Cornerstone Phase 4 CIS Replacement Presentation

Brad Bowness began with a status update, confirming that the CIS project is nearing the end of the Blueprint phase. The project schedule is on track to the baseline plan and the targeted "Go Live" of October 2012. The forecast cost at completion remains at $179.8 million (including contingency, which has not been used thus far). Brad further added that the contingency is "owned" by the Hydro One Board and cannot be used without their prior approval.

The Phase 4 Project involves four phases the first is the Blueprint phase which is nearing completion. One of the key objectives of the Blueprint phases is to validate the benefits and confirm benefits will be realized as part of the program. The requirements also have to be validated. The other three phases are Realization, Final Preparation, and Verification and Stabilization, which commences following Go-Live. The status of these phases and other Milestones such as Implementation Kickoff and Go-Live are progress reported regularly to senior management and the Hydro One Board.

Brad. explained that the process was intended to minimize customer impact, but that they would follow up about specific touch points with the customer.

Ted Cowan asked whether additional customer inputs through the Customer advisory Board would be included in the design phase. Brad responded that the Blueprint phase will be completed on October 31st, 2011 so the next consultation window would likely come after blueprinting. Ted confirmed that the Customer Advisory Board meets next on December 9th, 2011, and expected the matter could be discussed at that time. As a follow up to this item, it was confirmed that the Customer Advisory Board received an update regarding this project on September 29th.

Brad indicated that the Realization phase will commence in November 2011 and it will involve system configuration, building interfaces and data migration programs, change management communication plans and training design, and making sure that business process changes have been documented and are fully understood. Following Realization comes Final Preparation which ensures that business users understand and accept the system changes. It is also the point that data conversion is fully planned and tested. After Go-Live October 9th, 2012, the new system will be stabilized and verified.

Bill Harper asked when the old system will be retired. Brad responded that the Go-Live Milestone is scheduled for October 9th, 2012. He stated that the process generally requires 3-4 days to shut down the old system, migrate the data, set-up the new system and validate functioning appropriately and begin billing customers.

Susan Frank indicated, from a regulatory perspective, that the Go-Live date may not be the date that the assets go “into service”, in the regulatory framework. Hydro One is looking to go to USGAPP, which has criteria as to what is considered an in-service IT system. It is currently believed that some of the testing that occurs in the stabilization and verification phase has to happen before it can be considered “in-service”. This is why the words “in service” do not appear in the presentation. The actual in-service date is probably after October 9th, 2011 and could be as late as February 15th, 2013. These additional steps are for regulatory accounting purposes.

Brad then moved to his Slide 5 and outlined details of the CIS that were requested in the last consultation, including that:

- 15 current systems will be retired;
- 40 existing systems will be integrated with the new CIS;
- 68 Business Processes designs are included in this solution
- ±2700 Business Requirements have been met and will used throughout the project;
- 1500 employees and contract employees will be impacted as part of this implementation.

Hydro One will utilize change management methodology to address staff and customer impacts.

Michelle Byck Johnston asked what the total number of systems will be after retiring the old and integrating the new systems occurs.

Brad responded that across the landscape the application portfolio is broken up into 4 types of applications: core business, productivity tools, specialty software and system tools. Business systems (core, productivity, specialty) currently total approximately 800. Detailed information would be included in the filing. They have decommissioned upwards of 400 items across the 4 types driven by the Cornerstone Program, and are continuing to make progress. In follow up Hydro One confirms that it expects 15 business systems and an additional 10-15 system tools will be decommissioned as a part of CIS and replaced with 3 new business systems (SAP, Itron, Streamserve) and a small number of system tools.

The main functions of the CIS are in:

- Customer Service;
- Service Order and Work Management;
- Metering;
- Billing and Payment;
- Retail and Wholesale Market.

Each function in the CIS has several major IT components supporting it. Over 80 Interfaces will be built and tested within the 40 existing systems that will be integrated with the new CIS.

Brad's final Slide 9 provided a high level summary of the $179.8 million Project Total Cost.

ADJOURN 5:00pm

7. Appendices

A. Summary of Stakeholder Session

The Stakeholder Session was structured to afford stakeholders a concise summary of study results and progress reports on a number of fronts with the potential to inform the next round of Rate Applications, and to allow open, frank discussion of important issues and questions concerning:

1. Conservation and Demand Management (CDM);
2. Density and Cost Allocation;
3. Compensation Benchmarking;
4. Productivity and Metrics;
5. Cornerstone Phase 4—Customer Information System (CIS) Replacement.

Throughout the session, there was wide-ranging, free-flowing two-way discussion with Stakeholders, covering questions, issues of concern, requests for detail or explanation, challenges to various study premises and methods, and explicit requests for further input and consultation. Broadly stated, open questions and options include:

- Clarification of the Method used for load forecasting including CDM, and its suitability for co-ordination with OPA;

- Consumer input on the design phase of CIS replacement, through the Customer Advisory Board (Complete);
- Likely schedule for pending Rate Applications.

External consultants and Hydro One internal specialists explained the rationale, approach and results for each study, and indicated where further details and explanations would be forthcoming in the filing dossiers.

B. Key Actions and Notable Items

1. There was stakeholder interest in having volumetric/energy-billed and demand-billed rate classes separately broken out in CDM impact data, to ascertain whether either shows a greater price effect.

2. Stakeholders indicated a desire to have the impact of the Green Energy Benefit factored into CDM impact forecasting.

3. Stakeholders expressed an interest in a more robust and explicit comparison of the merits of the three prevalent Methods of forecasting CDM, including the resolution of data regression and collinearity issues.

4. Stakeholders asked for a clearer definition and explanation of reductions attributable to Increased Conservation Effect as compared to Natural Conservation, and of the specific value or benefit of including Increased Conservation Effect in load forecasting.

5. Hydro One indicated that it would clarify how Increased Conservation Effect growth will be forecast, once 2011 actual data is available.

6. Hydro One will consider including a review of the Seasonal Rate class cost allocation factors when implementing Density Cost Allocation Study results.

7. The CIS project leads were asked to present an update to the Customer Advisory Board at their December 9, 2011 meeting. Subsequently confirmed as complete on September 29th presentation to CAB

8. The exact number of systems affecting and affected by CIS replacement will be confirmed.

9. Hydro One confirmed that CIS Replacement project is "green" (on-track and on-budget) and has not yet had to use any of the contingency funds included in its total budget. Subsequently confirmed to be 15 business systems and approximately 10-15 system tools to be replaced.

10. Hydro One confirmed that the Distribution Rate application filing will be delayed to a date uncertain, but the new filing date will likely be early 2012.

C. Meeting Agenda

Stakeholder Consultation

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

AGENDA
October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

1:00 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:10 p.m.	Introduction	Bob Betts, Facilitator, OPTIMUS|SBR
1:20 p.m.	CDM Study	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
2:00 p.m.	Density Cost Allocation Study	Ben Grunfeld, London Economics
3:00 p.m.	**BREAK**	
3:15 p.m.	Compensation Benchmarking Study	Iain Morris, Mercer
4:00 p.m.	Productivity Study	Mark Hirschey, Oliver Wyman
4:30 p.m.	Cornerstone Phase 4 CIS Replacement	Brad Bowness, Director – Business Architecture, Hydro One Networks
5:00 p.m.	**Adjourn**	

Stakeholder Consultation Notes

2013 Distribution IRM Rate Application

June 5, 2012
Hydro One Networks Inc.
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 4:30 p.m.

OPTIMUS | SBR
REGULATORY SERVICES

Table of Contents

The presentation materials used in this session and background materials can be found at this link:

http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx

Participants

Stakeholders

- Larry Iwamoto – PowerStream
- Elena Yampolsky – PowerStream
- Patrick McMahon – Union Gas
- David MacIntosh – Energy Probe
- Judy Kwik – Power Workers' Union
- Shelley Grice – Association of Major Power Consumers in Ontario
- Vincent DeRose – Canadian Manufacturers and Exporters (via WebEx, phone)
- John McGee – Federation of Ontario Cottagers (via WebEx, phone)
- Mike Belmore – Society of Energy Professionals
- Ted Cowan – Ontario Federation of Agriculture
- Ethan Kohn – Ontario Power Generation
- Tom Ladanyi – Ontario Power Generation
- Bill Harper – Vulnerable Energy Consumers Coalition
- Mark Rubenstein – SEC
- Harold Thiessen – Ontario Energy Board
- George Vegh – Observer

Hydro One Networks Inc.

- Jim Malenfant – Hydro One
- Nai Yu Zhang – Hydro One

Presenters

- Allan Cowan – Hydro One
- Susan Frank – Hydro One
- Ian Malpass – Hydro One
- Henry Andre – Hydro One

OPTIMUS | SBR

- Bob Betts – OPTIMUS | SBR
- Angela Boychuk – OPTIMUS | SBR
- Tara Murphy – OPTIMUS | SBR

1. Welcome by Allan Cowan, Director, Major Applications, Hydro One

START 1:01pm

Allan Cowan welcomed all participants to the Stakeholder Consultation meeting, the first session for 2013 IRM Application. He stated that OPTIMUS | SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

2. Opening Remarks by Bob Betts, Facilitator, OPTIMUS | SBR

1:02pm

Bob welcomed the participants on the phone and introduced the OPTIMUS | SBR team as note-takers.

Bob began his presentation with several housekeeping items and pointed out the emergency procedures. Bob stated that notes will be taken during the meeting and that the meeting and discussions will be recorded. He mentioned that the recordings will be destroyed once the notes are produced. Any comments made will be attributed to the individual and the party they represent. Participants were instructed if they wanted comments to be off the record to advise beforehand.

Bob asked all attendees to introduce themselves, stating name and company for the record. He outlined the agenda for the day and listed the topics that would be discussed. He stated that all comments are appreciated and that the meeting notes will be available on Hydro One's website.

He stated that Hydro One had established two principle objectives for the consultation session. The first was to ensure that all participants thoroughly understood Hydro One's 2013 Incentive Rate Mechanism ("IRM") application and in particular the Incremental Capital Module ("ICM") component. The second was to identify any additional information that interveners felt would be helpful in their understanding, review and analysis of the application.

Bob invited Allan Cowan to start the first presentation, the 2013 IRM Overview.

3. 2013 Distribution Rate Application (IRM) Overview, Allan Cowan, Director, Major Applications, Hydro One

1:12pm

Allan began his presentation stating that on May 28, 2012 Hydro One filed the Transmission Rate Application and the initial portion of the 2013 Distribution IRM Rate Application with a note that the supporting evidence would be filed mid-June, 2012. Hydro One wanted stakeholder input before finalizing the evidence. Allan provided an overview of the process to determine the 2013 rate impact:

- Hydro One did not file an Incentive Regulation Mechanism (IRM) for 2012; as a result there is actually a slight decrease in the overall distribution rate because riders associated with Green Energy for Smart Grid came off. The net result is a -0.2% decrease;

- The first element of the application is the general Price Cap Index Adjustment (“PCI”) of (0.88%);
- The next major element of the application is Hydro One’s proposal for an Incremental Capital Module (ICM). In total Hydro One will be seeking recovery of total in-service capital additions of approximately $645 million (2.4% increase);
- The riders associated with Green Energy plan came off on December 31, 2011. Hydro One will be requesting the reinstatement of the rider with respect to Smart Grid OM&A to recover spending of $19.8 million (1.6% increase);
- In the current application Hydro One is not asking for a Z-Factor; but is having a pension valuation currently undertaken, and depending on the results of the valuation, may consider including a Z-Factor to deal with pension issues;
- The next item is the Tax Sharing Credit Refund, which is a decrease in income tax of $1.7 million over one year (0.1% decrease);
- There will be a disposition of the Group 1 Deferral and Variance accounts balance of $37.5 million over 2 years (1.7% decrease);
- There will be no disposition for Smart Meter Funding Adder, due to 150,000 smart meters that are not yet activated; and
- The overall Rate Impact of the application is a 3.1% increase, which equates to a 1.1% Bill Impact increase.

Allan continued by providing an overview of the other requests including:

- Adjustment to the Retail Transmission Service Rates (RTSR) to reflect the Board approved Uniform Transmission Rates (UTR) increases for 2011 and 2012;
- Approval to implement the final step of rate harmonization approved under EB-2007-0681; and
- Approval to implement the results of the Density Study (Board’s Directive), because of the cost and results of the study.

Bill Harper asked if the Price Cap Index would have the 2012 Productivity Factor of 0.72 replaced with the 2013 factor. Allan replied that the Productivity Factor of 0.72 would be replaced with the Board approved factor applicable to 2013.

Allan invited Susan Frank and Ian Malpass to the podium for their presentation on the ICM proposal.

4. 2013 ICM Application, Susan Frank, Vice President and Chief Regulatory Officer, & Ian Malpass, Director, Regulatory Pricing and Support, Hydro One

1:25pm

Susan began the presentation by stating that there are varying opinions on what an Incremental Capital Module (ICM) should look like and that it is important to clearly understand the choices. Susan reviewed the presentation agenda and asked Ian to begin.

Ian explained that the Threshold Test is the determination of whether an Ontario utility is eligible for ICM. He explained the formula and how the factors within it are calculated. He stated that based on the Threshold Test Hydro One was eligible to file the ICM.

Bill Harper asked for clarification on the approved rates, specifically whether the base distribution rate in the Threshold Value Formula is exclusive of the riders and adders. Ian confirmed that they were.

Ian then moved to the description of Hydro One's proposed ICM. He indicated that it follows the approach described by Susan and Hydro One in their submissions to the Board in the Renewed Regulatory Framework for Electricity consultation process.

Ian then reviewed the categories of capital investments in the Hydro One ICM, which were:

1. "Typical": Includes historically approved levels of sustainment and development spending;
2. "Escalated Issue": Includes spending on typical categories but at a substantial increase over historically approved levels; and
3. "Non-typical": exceptional items, not occurring often, such as the Customer Information System (CIS) Investment.

Judy Kwik asked if Escalated Issue capital investments occur because investment in previous years was insufficient.

Susan Frank responded that is likely not a factor and that escalated issues generally involve new information, new experiences or new failures. Susan used an example of a storm that damages and identifies multiple weak poles. It is work that is typical but at a higher level because of the new or better information.

Ian continued the presentation, stating that different OEB Panels used different considerations or determinations for assessing the appropriateness of an ICM, including "materiality", "need", "prudence", "extraordinary", "unanticipated", "non-discretionary", and "discrete". Hydro One perceives this as a lack of clarity in the use of the ICM.

Vince DeRose stated his view that the OEB considerations support Non-Typical capital investment and asked if Hydro One felt OEB considerations would also support Escalated Issue capital.

Ian replied that the ICM should cover both Non-Typical and Escalated Issues capital. He said the considerations may not allow Typical capital spending; however, Typical capital spending in excess of approved depreciation should be allowed as part of the ICM.

Ian then reviewed the current ICM approach and associated issues. The issues included:

- Limited testing of the approach,
- Typical capital spending not fully recovered by distributors whose Typical capital spending is significantly great than depreciation during the period of an IRM,
- Escalated Issue capital spending and Non-Typical spending also need to be recovered during IRM periods, and
- The current model results in step increases at Cost of Service rebasing, which Hydro One feels are not customer friendly.

Ian then provided the numerical support for why Typical capital spending is not recovered during the period of an IRM. He reviewed a table which determined the funded growth in rate base and loss in revenue was a result of Typical capital spend. Ian emphasized that depreciation is clearly insufficient to fund capital during an IRM. The table included the following data for the 2013:

- Typical Capital Expenditure ($414 million),
- Rate Base impact of Typical Capital Expenditure ($414 million),
- Less Rate Base funded by Depreciation (-$283 million),
- Less Rate funded by Growth in Revenue ($11 million),
- Unfunded growth in Rate Base ($142 million), and
- Lost Revenue associated with unfunded growth in Rate Base ($14 million).

Ian also explained the derivation of the $11 million Rate Base Funded by Growth in Revenue in detail.

Ted Cowan posed a question about negative growth. He asked if Hydro One looked at the situation where PCI stays stagnant and the negative growth continues to shrink, resulting in larger negatives. He added that the Ontario Federation of Agriculture ("OFA") considered this question and that they were concerned that the Rate Base Funded by Growth in Revenue would be very much below the negative $11 million calculated by Hydro One on slide 8.

Ian responded that Hydro One's loads are forecasted to level off; so for this portion of the equation, there will not be a large increase.

Ted questioned whether loads could level off while capital requirements were growing.

Susan Frank commented that their growth calculation is consistent with what the Board uses in the Threshold, which is a historic base and unaffected by future load changes. When Hydro One looks to the future, load will be flat. Load reduction is coming, especially if they meet CDM requirements. Therefore the concerns are realized at a slower rate. She noted that if a reduction exists, it will be proportionately assigned to Capital and to OM&A. Susan confirmed that Ted's thinking was correct, but that the movement of the load would be realized in the future.

Bill Harper advised that Hydro One was blending a combination of the ICM, using historical and forecasted total capital spend for 2013. He stated that one could do a load forecast for 2013 to determine the actual expected loss.

Susan added that Hydro One is not trying to forecast load for 2013. They are trying to determine the amount of money obtained with the current IRM formula. She said that they are determining how much PCI provides and also if the results are consistent with the Board. In theory you are getting more money from the growth.

Bill replied that he did not disagree, but that Hydro One presently looks at total forecast capital going forward, and asked why Hydro One is not looking at the load growth going forward as well.

Susan responded that when the OEB looks at the capital they always look at what goes in-service in the future year (IRM year), not in the past.

Bill said that Hydro One is departing from existing ICM methodology. The ICM model does not adjust capital based on total capital going into service, and that difference may justify using a future load forecast for the same period. Bill said that he has seen other utilities that include a load forecast in their application. Susan asked what utilities use this method. Bill said that FortisBC was under a similar ICM to the one Hydro One is applying for. It was inflation adjustment on OM&A coupled with a capital spend forecast and a load forecast to determine the capital spend forecast in the rates for the same period of time.

Susan asked how much testing it took for the load forecast. Bill responded that in this case they had a stakeholder group that reviewed the load forecast.

Ted Cowan stated Hydro One may want to look at a different cost allocation model for rate classes. He stated that the current model accelerates the exodus of customers, such as those that go to self-generation. He added that the model should be examined in advance of customers being driven to make their own power, which would create further load loss.

Susan said that this question is more closely related to the Density Study and will be examined in the next presentation.

Ian continued with his presentation, providing a summary of the funding of Typical capital spending.

- Hydro One would incur $14 million in lost revenue in 2013,
- The unfunded growth in rate base would be $142 million in 2013, and
- Other Impacts in 2013:
  - Hydro One will incur lost revenue of approximately $9 million per year due to ½ year rule applied to 2011 COS approved capital; and
  - Hydro One will also incur lost revenue of approximately $9 million per year for ½ year resulting from not applying for 2012 IRM.

John McGee asked Ian to specify the effective date for the 2013 application. Ian confirmed that the effective date is January 1, 2013.

Ian then outlined the potential negative outcomes of the current ICM:

- Hydro One is not in a position, due to credit rating issues, to invest in rate base for which there is no cost recovery; and
- Potential unintended customer outcomes:
  - Lower reliability as assets are not replaced or refurbished prior to breakdown,
  - Not replacing or refurbishing assets when it is economically beneficial to do so, and
  - Increased labour costs as a utility is unable to level work based on the most efficient use of labour resources.

John McGee asked about the cost of connecting renewed energy (Smart Grid). He stated that the amount of money spent does not seem to have a significant impact on rates and asked if that was correct.

Susan replied that when “Green Energy” investments were approved, Hydro One was given a rider to track the cost for all the capital. The rider stopped at the end of 2011, but Hydro One continued tracking expenditures and revenues. The “Green Energy” investments are going into a variance account for future recovery.

John McGee asked why Hydro One received a credit rating downgrade and whether it was related to “Green Energy”.

Ian replied that part of the reason was Hydro One tends to follow the Ontario Government, which was also downgraded. Susan commented that OPG was not so affected because it is not a debt issuer at this time.

Susan added that the DBRS report that came out this week talking about risk factors for regulated utilities was relevant to this conversation. It indicated that an IRM is more risky than cost-of-service (COS), which tends to get a full cost recovery, and makes IRM more risky in the short and long term. It also looked at capital recovery and concerns about having confidence getting recovery of the capital. The ongoing basic level of capital is not recovered today and there is no guarantee that COS will get the recovery. DBRS also said that variance accounts/investments pose a risk for recovery. These three items of the risk profile are all negative for Hydro One, and could affect their credit rating and their cost of debt.

Ian provided further details of Hydro One’s 2013 ICM application. The application includes:

- Establishment of a rate rider based on the full capital program for in-service additions in 2013;
- Recovery of full year revenue adjusted for depreciation, PCI and load growth;
- A need and prudence review of forecast changes to rate base; and
- 2013 Board approved cost of capital applied.

Bill Harper asked if Hydro One is applying the 2013 cost of capital factors only to the incremental capital or to the entire amount including the base amount.

Susan replied that the 2013 Board approved cost of capital is applied only to the new incremental capital, not the replacement capital. Susan stated that Hydro One is diverging from the Board. As it is new capital, Hydro One will use the new ROE. Directionally this lowers the ROE for the 2013 application. However, despite that, Hydro One is establishing this precedent to use the new ROE going forward, whether it benefits Hydro One or not. Susan then stated that Hydro One is also using the full year impact, not the half year. The current IRM also uses the full year, because it does not pick up the non-approved half-year from previous year. Susan also reminded parties that Hydro One is not trying to pick up the half year for 2012 that they missed.

Tom Ladanyi asked if he was correct in understanding that Hydro One would ask for a 2013 ICM rider, and then again ask for a 2014, and that would appear in rates, and this pattern would continue until re-basing. Ian confirmed this statement.

Bill Harper asked about 2015 and whether it would have a rider that looks at 2014 and 2015. He also questioned how depreciation should be treated in 2014.

Susan replied that no one should worry too much at this time about 2014 and 2015 and that this is a one year application for 2013 only, it is important to see how this application goes first. She said that Hydro One will have to think about how its 2014 application would look including the handling of depreciation.

Ian continued with his presentation at slide 12 reviewing Investment by Type and the total in-service additions.

That chart showed 2013 revenue requirements for: Typical capital at $14M, Escalated Issue at $7M and Non-Typical at $7M adding to a total of $28M. Those revenues drove distribution rate impacts of 1.2%, 0.6% and 0.6% respectively, totaling to 2.4%.

Bill Harper asked why the revenue impact for Non-typical was so low compared to the impact of the lower spending in the Escalated Issue category.

Allan explained that it was attributable to the accelerated CCA associated with the CIS in the Non-Typical category.

Vince DeRose questioned if Hydro One considered the Customer Information System (CIS) unanticipated.

Allan noted that this was identified as Phase 4 of the Cornerstone Initiative in previous sessions. It was originally targeted for 2016, but was advanced to be implemented in 2011-12 and in-service in 2013 because of back room contracts that would have meant implementation of new CIS and new CIS support in the same year.

Susan added the current billing system cannot accommodate new codes and requirements; therefore Hydro One is currently not in compliance. The CIS contributes to the Non-Typical investment as an IT project. Hydro One uses the normal tax treatment of half-year rule that allows the rider established in 2013 to carry over to the next year. Because the tax impact is so large, Hydro One would be covered over 2 years instead of 1. The difference is 100% recovery of the returns and half-year benefit on the tax.

Ian moved on to the next slide, which highlighted Typical, Escalated Issue and Non-Typical Capital Evidence to support the ICM Application.

- Typical:
  - Summary of capital program.
- Escalated Issue (Stations, Poles and TX Station capital Contribution):
  - 4 years of historic investment information to establish typical spending pattern,
  - Detailed age and asset condition information to defend spending to address escalated issues, and
  - Consistent with program COS evidence.
- Non-Typical (CIS Replacement):
  - Consistent with project COS evidence.

Ian added that requests made by stakeholders in previous sessions were included in the evidence.

Mark Rubenstein asked how capital for Escalated Issue and Non-Typical would fit into the long term capital plan and what the plan was for spend over the next few years.

Susan replied that the Escalated Issue capital would need to be defended again in the next year. Allan added that the evidence would show historical capital, compared to capital for 2013 and then ramped up level for forecast years.

Ted Cowan suggested that Escalated and Non-Typical capital could shift to Typical over long term, presented to Board as a prudent and efficient plan. Ted also suggested that Hydro One should work with other utilities to split cost of projects such as the cost of the new CIS.

Judy Kwik asked if in 2014 Hydro One were to come into an ICM would Escalated Issues from 2013 become Typical in 2014.

Susan replied that Typical costs would not be changed without a cost of service review with Board approval.

Bill Harper wondered if using the summary of Typical capital program would be adequate. He felt that Hydro One would need to demonstrate that 2011 Typical capital is reasonable for comparison to the amount in 2013 and that would depend on the case built for 2011. He also wanted to ensure that the whole program, including total Typical and amount for Escalated Issue spend, and reasons to support the program, would be provided as evidence.

Susan replied that Escalated Issue totals would need to be defended, especially if they are above previous year's escalated totals. She stated that if the Board is repeatedly approving Typical capital investment less evidence is required; it would be a summary of the programs, not a detailed defense.

Tom agreed that there is no need to provide full and detailed evidence.

Mark asked for the planned 2012 Capital Expenditure total. Allan replied that the capital spend for 2012 is $540 million.

Mark asked if there was any thought of doing a half year in 2013 and picking up the other half in 2014.

Susan replied that it would be a larger number then just using 2013.

Ted Cowan commented that capital budget could be 2-3 year forecast and OM&A could be 4 year forecast. Since OM&A is predictable, the Board could approve OM&A budget spend for 4-5 years out.

BREAK 2:48pm

5. Implementation of Density Study Findings, Henry Andre, Manager Pricing, Hydro One

3:07pm

Henry Andre began his presentation to review the findings of the Density Study and the options being considered for implementation of the Density Study as part of Hydro One's IRM application for 2013 rates. There have been 3 previous sessions describing the Density Study. Henry focused on the findings in this session. The three key findings of the study were:

- Statistically significant relationship between density and cost-to-serve;
- Three density based classes for residential and two for General Service classes is appropriate; and
- Do not recommend wholesale changes to existing rate classes at this time.

The key finding was that they were able to quantify the relationship between customer density and cost-to-serve. For OM&A and Fixed Asset Costs:

- A Medium Density area costs 1.9 times more than a High Density area to serve; and
- A Low Density area costs 4.8 times more than a High Density area to serve.

When considering all costs (including customer related, non-density related costs, spread uniformly by customer):

- A Medium Density area costs 1.7 times more than a High Density area to serve; and
- A Low Density area costs 3.9 times more than a High Density area to serve.

Bill Harper asked how the High, Medium and Low Density areas relate to the existing customer classes, specifically he asked where the General Service class would fit.

Henry replied that the General Service would be somewhere between Medium and Low Density, but the study did not look at the specific composition of Hydro One's General Service class.

Bill said that the presentation slides do not make reference to the 2 General Service classes and asked if Henry could make reference to them where applicable. Henry agreed.

Ted Cowan asked if Hydro One reviewed the most costly 5% of the very Low Density and the most costly 5-10% of the General Service Group, how many customers would be in this combined group and what would the costs look like.

Henry replied that Hydro One had not looked at this. This is a question that relates more specifically to the general cost allocation methodology for Hydro One rate classes and they are not looking at revisiting the rate classes as part of the IRM. He stated that making changes to the rate classes would be undertaken in a cost of service (COS) application.

Ted continued saying that these customers (most costly 5%) have 5 times the cost and are in need of rural rate assistance. Ted also suggested that it could be more cost effective to buy this costly group off the grid.

Henry continued his presentation by reviewing the 2010 Cost Allocation Model results. Hydro One used the number of customers associated with each rate class to determine the cost per customer. They looked at the Total Costs and OM&A plus Fixed Asset Costs to determine the ratio.

- Ratio of Total Cost per Customer:
  - Medium Density (R1) was 1.6 times the cost of the High Density (UR);
  - Low Density (R2) was 2.8 times the cost of the High Density (UR); and
  - Seasonal was 1.5 times the cost of the High Density (UR).
- Ratio of OM&A and Fixed Asset Cost per Customer
  - Medium Density (R1) was 1.7 times the cost of the High Density (UR);

- Low Density (R2) was 3.1 times the cost of the High Density (UR); and
- Seasonal was 1.7 times the cost of the High Density (UR).

Henry compared the results of the 2010 Cost Allocation Model to the results of the Density Study, using two alternate approaches, Option A: Total Costs and Option B: OM&A and Fixed Asset Costs. The Density Study adjusted cost allocation model results using Option A identified a much higher differential between the 3 classes than is shown using Option B. Henry stated that Hydro One also did these calculations for the General Service class and found that there is some differential (slightly more than the R1, but not as high as the R2). He focused on the residential classes, because Hydro One believes the General Service classes do not require immediate attention. Henry stated that Hydro One can include the General Service class results in the evidence.

Bill stated that if Hydro One does not want to take immediate action on the General Services classes then they will need to explain why in the evidence.

Henry concluded that based on the Density Study there needs to be some immediate cost allocation adjustments between the residential rate classes. He asked stakeholders if Hydro One should be using Total Costs or the OM&A and Fixed Assets when altering Cost Allocation Model to align with the Density Study.

Ted questioned if the Total Cost per Customer is actually Total Cost per Account. He stated that average farms have three accounts; therefore the individual customer will be receiving three bills and could be interested in consolidating the three bills by going off the grid. Ted added that Hydro One needs to identify the number of customers. Henry advised he will check if total cost is by customer or account.

John McGee requested that in the submission to the OEB, Hydro One should include the number of customers in each of these classes.

Henry replied that the number of customers will be presented upfront in the application.

Bill Harper replied to Henry’s question regarding the use of Total Cost vs. OM&A and Fixed Asset to alter the Cost Allocation Model. He advised to use the OM&A and Fixed Asset Costs, which is a Board approved method, rather than using the Total Costs for allocations.

Bill added that if the General Service classes were added to the ratios shown in the options for implementation the results could differ. He also stated that this assumes no density consideration in the differentiation of allocation of cost for other classes, excluding General Service and Residential; he believes there may be some debate over this.

Mark Rubenstein stated that he believes Hydro One should be prepared to include General Service data in the application. Henry indicated that Hydro One would do so in its evidence.

With respect to general Cost Allocation methodology, Ted Cowan stated that Hydro One should consider subdividing each of the classes, so that there is no internal cross-subsidy within a class or external cross-subsidy between classes. He stated that this would help reduce underestimation and generalization of the issues. Henry stated that looking internally within a class would be difficult, but he understood Ted’s point. Ted stated that he believed Hydro One has the information that would allow them to do the internal class analysis.

John McGee asked if Hydro One had the amount of the Rural Rate Protection charge, allocated to the R2 class, per customer per month. Henry replied that it is $28.50 per customer per month.

Henry continued his presentation by reviewing the Density Study Adjusted (DSA) Cost Allocation Model results. He reviewed the DSA costs, Revenue Collected, Revenue to Cost (R/C) Ratio and compared the 2010 Approved R/C ratio for both options:

- Option A: Total Costs
  - UR: DSA R/C Ratio = 1.36
  - R1: DSA R/C Ratio = 1.07
  - R2: DSA R/C Ratio = 0.93
  - Seasonal: DSA R/C Ratio = 1.09
- Options B: OM&A and Fixed Asset Costs
  - UR: DSA R/C Ratio = 1.34
  - R1: DSA R/C Ratio = 1.06
  - R2: DSA R/C Ratio = 0.92
  - Seasonal: DSA R/C Ratio = 1.17

Henry stated that the results in both cases show that R2 is underpaying and that the Seasonal Class overpays much more in Option B.

Bill Harper stated that the General Service classes need to be included because currently the revenue collected from General Service is divided between the 4 other classes. Henry replied that he would have to think about the suggestion.

Ted stated that some of the customers in R2 are already paying their full share of the costs, but others are not and the ones currently paying their full share of the costs will be impacted more by the rate adjustment. He restated that Hydro One needs to consider reviewing the internal composition of the classes for internal and external cross-subsidy.

Henry then reviewed the 2013 Implementation of the Study Results. The options are:

1. Bring the density study-adjusted revenue-to-cost ratios for classes exceeding Board limits to previously approved levels.
   - Lower UR R/C ratio to 1.09 and Seasonal R/C ratio to 1.03,
   - Better aligns with previous Board decision,
   - Rates will more closely reflect cost of serving rate class, and
   - Addresses existing rate disparity more quickly.
2. Bring density study-adjusted revenue-to-cost ratios to within Board approved range
   - Lower UR and Seasonal R/C ratio to 1.15,
   - Meets minimum Board Requirements, and
   - Addresses existing rate disparity more slowly.

Henry asked the stakeholders for input on the most appropriate option.

Bill stated that he believes Option B is most appropriate, depending how Hydro One handles the General Service class. He was not sure if using 2010 data to adjust 2014 costs is an overall improvement. He suggested that for the next Cost of Service application the study results will no longer apply to the customer counts and loads and will need to be reviewed for 2015.

Henry stated that the context of the IRM application is to address immediate issues that require attention. He agreed that for a Cost of Service application, the method of incorporating the Density Study findings into the Cost Allocation Model should be considered.

Henry agreed that Option B addresses the problem and that Option A could be impacted by how it rolls through the Cost Allocation Model, and Hydro One does not want to overshoot the target. He stated that bringing it within the range at this time is the best option because more evidence and data would be required to support Option A. Henry stated that perhaps before the next IRM or Cost of Service Hydro One could get that data.

Henry then reviewed the proposed rate class impacts in each of the options. For Option A the average distribution rate impacts are:

- -18.7% for UR,
- No impact for R1,
- +5.4% for R2, and
- -12.3% for Seasonal

For Option B, the average distribution rate impacts are:

- -14.3% for UR,
- No impact for R1,
- +2.5% for R2, and
- -2.1% for Seasonal

Regarding the Total Bill Impacts which were about one-third of Distribution Impacts, John McGee stated that seasonal class customers have a variety of consumption rates, so the total bill impacts would not be constant. He then recommended that Option B should be implemented in order to gradually phase in the changes for all classes. Henry agreed that the impact for low consuming Seasonal Distribution customers will represent more than 1/3 of the Total Bill.

Ted stated that both options have obvious inequality between the classes, but that there is unexposed inequality within the classes. He said that the difference between customers is diluted and the major issue is still hidden in the largest customer class, R2, because of subsidies. He stated that the data will not help the Board understand or help Hydro One find the problem. Option B is a smoother transition, but does not address the problem. Ted stated that the R2 class needs to be analyzed on its own to find the issues.

Susan asked John about his reasoning for choosing Option B, specifically when the next step of phasing should be implemented.

John stated that the OEB should determine the Revenue to Cost ratio ranges, so they would determine the next step in the phasing. He then stated that Hydro One could decrease it slowly each year as long as they had a high level of confidence in the cost allocation. He believes that Hydro One has high confidence in Density Study, therefore each year there should be a minor adjustment to get to 1.00 for all classes.

Bill asked why the total revenue was held constant across the classes when doing the adjustments and if there was any class that had an approved revenue to cost ratio less than 0.92, would the appropriate approach be to move that class up first before addressing the R2.

Susan asked if this comment supported Bill's point earlier about the General Service class.

Bill said that it is the same issue on both sides, the "cost" for the denominator and "revenue" for the numerator. He stated that other rate classes should not be combined or excluded from these calculations.

Susan said that she was struggling with the notion that the Density Study allocates costs differently across Residential and General Service and how the cost allocation would change.

Bill stated that the relativity between classes should be included in the rate distribution costs across all classes. He noted that isolating just residential does not make sense because the isolated costs are the result of the cost allocation that did not properly account for density.

Henry added that one issue may be that the Density Study focused on the relative cost of serving those classes as opposed to the absolute cost. He added that the Cost Allocation model does not allocate cost uniformly across the classes.

Bill stated that the Cost Allocation model does not treat R1 vs. R2 differently than R1 vs. GS customers.

Henry replied that it is not obvious how costs will be allocated differently across the classes.

Susan said that the variables for assigning cost to a UR Residential vs. a UR General Service for example, are not clear. Hydro One has to stay within the Residential and the General Service for the cost step. Susan added that for the revenue to cost ratio can be looked at across all classes.

Shelley Grice advised that AMPCO consistently advocates for revenue to cost ratios to move toward 1 as quickly as possible; therefore she believes Option A is the better approach and that it should be implemented as soon as possible.

Susan stated that Hydro One was going to make a recommendation to the Board based on the Stakeholder feedback, but that they will include all of the evidence and options in the filing. The stakeholders agreed that all options should be presented.

6. Other Interest Areas, Allan Cowan, Director, Major Applications, Hydro One

4:19pm

Allan Cowan concluded the session by thanking all Stakeholder's for their input and stating that it will be taken into consideration when finalizing the evidence. Hydro One is aiming to have the remaining evidence submitted by mid-June 2012.

ADJOURN 4:20pm

7. Appendices

A. Summary of Stakeholder Session

The Stakeholder Session was conducted to present justification and information supporting the 2013 IRM Application with specific attention to the Incremental Capital Module (ICM), as well as implementation of the Density Study findings. This session was aimed to achieve two objectives:

1. To collect stakeholder feedback on the type of information to be submitted as evidence for the 2013 Distribution IRM Application, and
2. To collect stakeholder feedback and opinions on the suggested options to implement the density study findings.

Throughout the session, there was open two-way discussion with Stakeholders, covering questions, issues of concern, additional information for consideration, requests for detail or explanation, and requests for further input and consultation.

Hydro One internal specialists explained the rationale, approach and results for the Application and Density study, and indicated where further details and explanations would be provided in the filing.

B. Key Actions and Notable Items

2013 ICM Application

- Stakeholders asked if Hydro One looked at the situation if PCI remains stagnant and the negative growth shrinks, larger negatives will result, and expressed concern that, in Typical Spend, the value for Rate Base Funded by Growth in Revenue was larger than $11 million.
- Stakeholders requested consideration be given to using a forecasted load if Hydro One is looking at forecasted capital for 2013.
- The representative from the OFA commented that a review of the cost allocation model should happen before agricultural customers are forced to start making their own power and leave the grid.
- Hydro One will consider the handling of depreciation in riders for 2014 and subsequent years, for applications beyond this one for 2013.
- Stakeholders questioned the length of time for depreciation for each of the investment types, expressed concern that the CCA half-year rule would extend risk into 2014 against fallen revenues. Hydro One offered to show the math on the $7 million value.
- Stakeholders requested information to understand how Escalated Issues and Non-typical capital would fit in the long term capital plan. Hydro One will include, as part of evidence, historical units, spend for 2013 and ramped up level for next few years.
- Stakeholders suggested that Escalated and Non-typical spend could be shifted to Typical spend over long term.
- Stakeholders suggested that Hydro One work with other utilities to share the cost of capital projects such as the CIS.

- Stakeholders questioned if using the summary for the Typical capital program would be adequate. They felt that Hydro One would need to demonstrate that 2011 Typical capital is reasonable as a base for 2013.
- Stakeholders wanted to ensure that the application include the whole program, with total Typical and Escalated Issue spending, and reasons supporting the program.

Implementation of Density Study Findings

- Several stakeholders wanted Hydro One to expand the implementation plan for the Density Study to include other classes and other cost allocation methodology issues. Hydro One responded that this was more appropriate for a cost of service application.
- Hydro One indicated that they would explain in the application why the General Services classes were not included in the Density Study implementation.
- Stakeholders questioned if 'Total Cost per Customer' was by customer or account, citing that farms can have 3 accounts. Hydro One to check if total cost is per customer or per account.
- Stakeholders suggested that it would be helpful to include the number of customers or accounts in the table. Hydro One will include the data.
- Stakeholders requested further consideration to having density considerations also include the two General Service classes, not just the 4 residential classes of UR, R1, R2 and Seasonal.
- Stakeholders commented that using the 2010 Cost Allocation Model methodology may not be adequate for adjusting costs to implement the Density Study. For next cost of service, Hydro One will need to think about cost allocation model inputs.
- All stakeholders that responded with their choice of Option A: Total Cost allocation or Option B: OM&A and Fixed Asset Costs allocation chose Option B. With respect to adjusting the revenue-to cost (R/C) ratio Option A: Move to R/C ratios approved by Board in last COS application or Option B: Move to limit of Board approved R/C ranges, all stakeholders that responded with their choice favoured Option B, except for AMPCO based upon their principle of moving to ratios of 1 as quickly as possible. Stakeholders questioned if any classes were below 0.92 in 2010 approved cost allocation, suggesting that there may be other candidates for adjustment before moving R2.
- Stakeholders agreed with Susan Frank that Hydro One should include all evidence and their recommendation for all Options in the filing.

C. Meeting Agenda

AGENDA

June 5, 2012

Hydro One Networks Inc.

Special Event Room, Ground Floor
483 Bay Street, North Tower
1:00 pm to 4:30 pm

TIME	ITEM	PRESENTER
1:00 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:05 p.m.	Introduction	Bob Betts, Facilitator, OPTIMUS | SBR
1:10 p.m.	Overview of 20 13 Distribution Rate Application (IRM)	Allan Cowan, Director, Major Applications, Hydro One Networks
1:30 p.m.	2013 ICM Application	Susan Frank, Vice President and Chief Regulatory Officer, and Ian Malpass, Director Regulatory Pricing and Support, Hydro One Networks
3:00 p.m.	**Break**	
3:15 p.m.	Density Study	Henry Andre, Manager Pricing, Hydro One Networks
4:15 p.m.	Other areas of interest	Allan Cowan, Director, Major Applications, Hydro One Networks
4:30 p.m.	**Adjourn**	

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2011

INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the balance sheet as at December 31, 2011, the statement of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Distribution Business (a business of Hydro One Networks Inc.) as at December 31, 2011 and the results of its operations and its cash flows for the year then ended in accordance with basis of accounting as set out in Note 2 to these financial statements.

Basis of Accounting and Restriction on Use

Without modifying our opinion, we draw attention to Note 2 to these financial statement, which describes the basis of accounting and composition of the Hydro One Networks Inc. that comprise Distribution Business. In particular, in preparing these financial statements, corporate long-term debt, shared functions and services costs and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
April 2, 2012

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Revenues		
Energy sales	3,398	3,157
Rural rate protection *(Note 16)*	125	125
Other	46	46
	3,569	3,328
Costs		
Purchased power *(Note 16)*	2,285	2,156
Operation, maintenance and administration *(Note 16)*	555	554
Depreciation and amortization *(Note 3)*	287	277
	3,127	2,987
Income before financing charges and provision for payments in lieu of corporate income taxes	442	341
Financing charges *(Notes 4 and 16)*	140	139
Income before provision for payments in lieu of corporate income taxes	302	202
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	66	8
Net income and comprehensive income	236	194

See accompanying notes to Financial Statements.

BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2011**	**2010**
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	141	86
Accounts receivable (net of allowance for doubtful accounts - $15 million; 2010 - $22 million) *(Note 16)*	744	710
Regulatory assets *(Note 8)*	9	25
Materials and supplies	4	5
Future income tax assets *(Note 5)*	8	12
Other	7	2
	913	840
Fixed assets *(Note 6)*:		
Fixed assets in service	7,863	7,397
Less: accumulated depreciation	2,870	2,690
	4,993	4707
Construction in progress	293	269
Future use land, components and spares	39	39
	5,325	5,015
Other long-term assets:		
Regulatory assets *(Note 8)*	361	338
Intangible assets (net of accumulated amortization) *(Note 7)*	108	76
Goodwill	73	73
Other	9	2
	551	489
Total assets	6,789	6,344

See accompanying notes to Financial Statements.

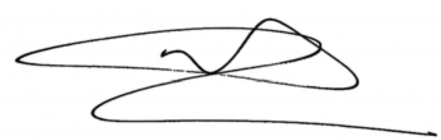
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2011**	**2010**
Liabilities		
Current liabilities:		
Accounts payable and accrued charges *(Notes 13 and 16)*	692	561
Regulatory liabilities *(Note 8)*	16	47
Accrued interest	31	31
Long-term debt payable within one year *(Notes 9, 10 and 16)*	324	176
	1,063	815
Long-term debt *(Notes 9, 10 and 16)*	2,565	2,658
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	576	543
Environmental liabilities *(Note 13)*	134	157
Future income tax liabilities *(Note 5)*	171	154
Regulatory liabilities *(Note 8)*	105	34
Asset retirement obligations *(Note 14)*	3	3
Long-term accounts payable and other liabilities	4	4
	993	895
Total liabilities	4,621	4,368
Contingencies and commitments *(Notes 18 and 19)*		
Excess of assets over liabilities *(Notes 11 and 15)*	2,168	1,976
Total liabilities and excess of assets over liabilities	6,789	6,344

See accompanying notes to Financial Statements.

On behalf of the Board:

Laura Formusa
Chair



Sandy Struthers
Director

STATEMENTS OF CASH FLOWS

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities		
Net income	236	194
Environmental expenditures	(8)	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	242	234
Regulatory asset and liability accounts	40	3
Future income taxes	(9)	(9)
Gain on interest rate swap agreements	(3)	(5)
Other	4	-
	502	408
Changes in non-cash balances related to operations *(Note 17)*	128	58
Net cash from operating activities	630	466
Financing activities		
Allocated long-term debt issued	225	500
Allocated long-term debt retired	(176)	(197)
Payments to Hydro One to finance dividends	(45)	(7)
Other	(1)	-
Net cash from financing activities	3	296
Investing activities		
Capital expenditures		
Fixed assets	(539)	(585)
Intangible assets	(57)	(5)
	(596)	(590)
Other assets	18	20
Net cash used in investing activities	(578)	(570)
Net change in inter-company demand facility	55	192
Inter-company demand facility, January 1	86	(106)
Inter-company demand facility, December 31	141	86

See accompanying notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF THE DISTRIBUTION BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These financial statements have been prepared in accordance with the accounting policies summarized below. These policies are consistent with Canadian generally accepted accounting principles (GAAP) as contained in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook - Accounting. These financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2011 have been prepared and are publicly available.

These financial statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The financial statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of that business. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position and results of operations and cash flows that would have resulted had the Distribution Business historically operated on a stand-alone basis.

These financial statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs are allocated to the Distribution Business on a fully-allocated basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these financial statements represent allocations subject to review and approval by the OEB.

Rate-setting

The rates of the Company's electricity Distribution Business are subject to regulation by the OEB.

In January 2009, Hydro One Networks filed an updated incentive regulation distribution rate application for 2009 rates on the basis of the OEB's third-generation Incentive Regulation Mechanism (IRM) process, which adjusts previously established rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming into service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision with reasons approving the basic IRM increase and a rate adder of $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009.
In 2009, Hydro One Networks filed a cost-of-service rate application with the OEB for 2010 and 2011 distribution

rates. This reflected the Company's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the Green Energy Act (GEA). The application sought OEB approval of distribution revenue requirements of approximately $1,150 million and $1,264 million for 2010 and 2011, respectively.

On April 9, 2010, the OEB released its decision with reasons approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The OEB also approved the disposition of certain distribution-related regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, Regulatory Asset Recovery Account I, retail cost variance accounts and smart meter amounts. The OEB ordered that the approved balances be aggregated into a single regulatory liability account (Rider 6) to be recovered over a 20-month period from May 1, 2010 to December 31, 2011.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Distribution Business' regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Distribution Business has recorded regulatory liabilities, which represent amounts incurred in different periods than would be the case had the Distribution Business been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in its results of operations in the period that the assessment is made. The specific regulatory assets and liabilities recognized at December 31, 2011 are disclosed in Note 8.

Revenue Recognition

Revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company's Distribution Business estimates revenue for each monthly period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2011 amounted to $513 million (2010 - $462 million).

Revenue also includes an amount relating to rate protection for rural residential customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential consumers by reducing the electricity rates that would otherwise apply.

Revenue also includes amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario) prior to 2009) as modified by the *Electricity Act, 1998*, and related regulations.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that they are more likely than not to be realized from taxable income available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the “more likely than not” criterion. Previously unrecognized future income tax assets are re-evaluated at each balance sheet date and are recognized to the extent that they have become more likely than not of being recovered from future taxable income.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-setting process.

Inter-Company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers’ acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers’ acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities.

Fixed assets in service consist of distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land, major components and spare parts, and capitalized development costs associated with deferred capital projects.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, buildings associated with communications assets, administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred to acquire land rights and other access rights.

Intangible Assets

Intangible assets primarily represent computer applications software assets. These assets are capitalized at cost, which comprises purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital development.

Construction and Development in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully-allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2011 - 4.20%; 2010 - 4.34%).

Depreciation and Amortization

The capital costs of fixed assets and intangible assets are depreciated or amortized on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external review of its fixed asset and intangible asset depreciation and amortization rates, as required by the OEB and Canadian GAAP. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Distribution	1% - 5%	2%
Communication, Administration and Service	1% - 15%	8%
Easements	1%	1%

Intangible assets are primarily included within the communication, administration and service classification above and these assets are amortized on a straight-line basis. Amortization rates for computer applications software and other intangible assets range from 9% to 11%. Depreciation rates for finite life easements are based on their contract lives. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of fixed assets or intangible assets that are normally retired is charged to accumulated depreciation or amortization, with no gain or loss reflected in current results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where no asset retirement obligation has been recorded.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis consistent with their inclusion in electricity rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against results of operations. The Company has determined that goodwill is not impaired.

Financial Instruments

Recognition and measurement

All financial instruments are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other assets and liabilities; or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Balance Sheets except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in other comprehensive income (OCI) until the instrument is derecognized or impaired. The Distribution Business has classified its financial instruments as follows:

Assets / Liabilities	Classification	Measurement
Accounts receivable	Loans and receivables	Amortized cost
Inter-company demand facility	Other assets	Amortized cost
Accounts payable	Other liabilities	Amortized cost
Long-term debt (unless otherwise specified)	Other liabilities	Amortized cost
Fixed-to-floating interest-rate swaps	Not classified	Fair value
$100 million of a $250 million note matured on March 3, 2011	Not classified	Fair value
$100 million of a $500 million note due November 19, 2014	Not classified	Fair value
$100 million of a $500 million note due September 11, 2015	Not classified	Fair value
Floating-to-fixed interest-rate swaps	Held-for-trading	Fair value

In March 2008, January 2010 and January 2011, Hydro One issued notes for long-term financing under its Medium-Term Note (MTN) Program in the amounts of $250 million, $500 million and $250 million, respectively. The first $250 million issue, $250 million of the $500 million issue and the second $250 million issue were mirrored down to Hydro One Networks through the issuance of inter-company debt with $100 million of each issue allocated to the Distribution Business. These amounts were designated as part of a hedging relationship. As at December 31, 2011, derivative instruments include fixed-to-floating interest-rate swap agreements with a total amount of $200 million to convert the $200 million of fixed rate debt into three-month variable-rate debt as well as floating-to-fixed interest-rate swap agreements with a total amount of $220 million that locks in the rate resets on $220 million floating rate debt for 2012. These long-term debt issues, and related hedging instruments, are not classified.

All financial instrument transactions are recorded at trade date.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the term of the related debt using the effective interest method.

Transaction Costs

Transaction costs related to Hydro One Networks' proportionate share of the relevant Hydro One transaction, for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

Derivative Instruments and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Balance Sheets unless exempted from derivative treatment as a normal purchase and sale or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. The Company does not have any significant embedded derivatives in contracts that require separate accounting and disclosure.

All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The gain or loss related to the ineffective portion, if any, is recorded in financing charges.

The Company does not engage in derivative trading or speculative activities.

Hydro One periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, Hydro One formally documents the hedging relationship between the hedged item and the hedging instrument, its risk management objective for establishing the hedging relationship, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items. These hedges are mirrored by the Company.

Comprehensive Income

Comprehensive income is comprised of the Distribution Business' net income and OCI. OCI includes the amortization of the Distribution Business' share of the Company's net unamortized hedging losses on the Company's proportionate share of Hydro One's discounted cash flow hedges, and the change in fair value on the Company's proportionate share of existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt.

Financial Instrument Disclosures

All financial instruments measured at fair value are categorized into one of the three levels of hierarchy. Each level is based on the transparency of the inputs used to measure the fair values of assets and liabilities:

Level 1 – inputs are unadjusted quoted prices of identical instruments in an active market;
Level 2 – inputs do not have quoted prices but are observable for the asset or liability, either directly or indirectly; and
Level 3 – inputs that are not based on observable market data.

The fair market value of the Company's long-term debt is determined using the fair value hierarchy levels disclosed in Note 10.

Employee Future Benefits

Employee future benefits provided by Hydro One and its subsidiaries include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed and intangible assets.

Environmental Costs

The Distribution Business records a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recorded to reflect the future recovery of these costs from customers. The Distribution Business reviews its estimates of future environmental expenditures on an ongoing basis.

Asset Retirement Obligations

When required by force of law or regulation, the Distribution Business records an asset retirement obligation based on the present value of the estimated fair value expenditures to remove certain assets and mitigate related sites. Where the Distribution Business anticipates that the related expenditures will be recoverable in future rates, a corresponding amount is capitalized as a cost of the related fixed assets. Some of the Distribution Business' assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Distribution Business expects to use the majority of its facilities in perpetuity, no asset retirement obligation currently exists. If, at some future date, a particular facility is shown not to meet the perpetuity criterion, it will be reviewed to determine whether a measurable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time. The asset retirement obligations recorded to date are primarily related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of the Company's facilities.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year.

Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Emerging Accounting Changes

Accounting Framework

The Company previously anticipated it would apply International Financial Reporting Standards (IFRS) to the Financial Statements of its regulated businesses for fiscal periods beginning on or after January 1, 2012. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of this year. On July 7, 2011, Hydro One filed an application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* that would otherwise require it to file Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. Hydro One's application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for its 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved Hydro One's application and granted it the requested exemptive relief. Hydro One's Board of Directors has approved a resolution authorizing it to report under US GAAP.

As a result, the Company, as a subsidiary of Hydro One, will prepare its December 31, 2012 Financial Statements based on US GAAP with two years of comparative restatement. The Company's opening US GAAP Balance Sheet will be based on a retrospective application of US GAAP. The Company anticipates that its current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's Financial Statements will be assessed as part of the Company's US GAAP conversion project.

On December 1, 2011, the Company submitted an application to the OEB asking for approval to adopt US GAAP as the approved basis for rate-setting and regulatory accounting and reporting for its Distribution Business in preference to modified IFRS.

3. DEPRECIATION AND AMORTIZATION

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Depreciation of fixed assets in service	212	196
Amortization of intangible assets	22	21
Fixed asset removal costs	45	43
Amortization of regulatory and other assets	8	17
	287	277

4. FINANCING CHARGES

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Interest on long-term debt payable *(Note 16)*	152	150
Other	1	(1)
Less: Interest capitalized on construction and development in progress	(11)	(9)
Interest on inter-company demand facility	(2)	(1)
	140	139

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5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in millions)	**2011**	**2010**
Income before provision for PILs	302	202
Federal and Ontario statutory income tax rate	28.25%	31.00%
Provision for PILs at statutory rate	85	63

Increase (decrease) resulting from:

Net temporary differences included in amounts charged to customers:

Pension contributions in excess of pension expense	(10)	(11)
Overheads capitalized for accounting but deducted for tax purposes	(5)	(5)
Capital cost allowance in excess of depreciation and amortization	(4)	(33)
Interest capitalized for accounting but deducted for tax purposes	(3)	(3)
Employee future benefits other than pension expense in excess of cash payments	3	2
Environmental expenditures	(2)	(3)
Other	1	(3)
Net temporary differences	(20)	(56)
Net permanent differences	1	1
Total income tax provision for PILs	66	8
Current income tax provision for PILs	75	17
Future income tax provision for PILs	(9)	(9)
Total income tax provision for PILs	66	8
Effective income tax rate	21.85%	3.96%

The provision for payments in lieu of current income taxes of $75 million represents the amount payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2011 is $50 million (2010 - $9 million).

The payments in lieu of future income taxes recoverable of $9 million reflects the decrease in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Distribution Business' customers through future rates.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the the Distribution Business' assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	**2011**	**2010**
Future Income Tax Assets		
Employee future benefits other than pension expense in excess of cash payments	200	189
Environmental expenditures	36	42
Other	1	3
Total future income tax assets	237	234
Less: current portion	10	15
	227	219

December 31 (Canadian dollars in millions)	**2011**	**2010**
Current future income tax assets	10	15
Current future income tax liabilities	(2)	(3)
Net current future income tax assets	8	12

Future Income Tax Liabilities		
Capital cost allowance in excess of depreciation and amortization	374	334
Amounts paid but not recognized for accounting purposes	19	35
Goodwill	7	6
Other	-	1
Total future income tax liabilities	400	376
Less: current portion	2	3
	398	373

Long-term future income tax assets	227	219
Long-term future income tax liabilities	(398)	(373)
Net long-term future income tax liabilities	(171)	(154)

The increase in the liability for payments in lieu of future income taxes that is expected to be recovered from customers through future rates has resulted in an increase in regulatory assets.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Cost	Accumulated Depreciation	Construction in Progress	Total
2011				
Distribution	7,090	2,440	243	4,893
Communication, administration and service	804	426	50	428
Easements	8	4	-	4
	7,902	2,870	293	5,325
2010				
Distribution	6,744	2,301	252	4,695
Communication, administration and service	684	385	17	316
Easements	8	4	-	4
	7,436	2,690	269	5,015

Financing costs are capitalized on fixed assets under construction using the OEB's approved allowance for funds used during construction on regulated assets and were $10 million in 2011 (2010 - $9 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Cost	Accumulated Amortization	Development in Progress	Total
2011				
Computer applications software	217	153	44	108
Other assets	1	1	-	-
	218	154	44	108

December 31 (Canadian dollars in millions)	Cost	Accumulated Amortization	Development in Progress	Total
2010				
Computer applications software	202	130	4	76
Other assets	1	1	-	-
	203	131	4	76

Financing costs are capitalized on intangible assets under development using the OEB's approved allowance for funds used during construction on regulated assets and were $1 million in 2011 (2010 - $nil).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	**2011**	**2010**
Regulatory assets:		
Future income tax regulatory asset	181	151
Environmental	142	166
Pension cost variance	29	16
Rider 2 (Regulatory asset recovery account II)	11	11
Rural and remote rate protection variance	-	7
Rider 4 (Revenue recovery account)	-	5
Other	7	7
Total regulatory assets	370	363
Less: current portion	9	25
	361	338
Regulatory liabilities:		
Rider 8	41	9
Retail settlement variance accounts	40	21
Rider 3 (Regulatory liability refund account)	9	19
Future income tax regulatory liability	7	8
Rural and remote rate protection variance	8	-
PST savings deferral	6	1
Rider 6	-	19
Other	10	4
Total regulatory liabilities	121	81
Less: current portion	16	47
	105	34

Regulatory Assets

Future Income Tax Regulatory Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the Distribution Business' provision for PILs would have been higher by approximately $22 million (2010 - $28 million) including the impact of a change in substantively enacted tax rates.

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Distribution Business has recorded an equivalent amount as a regulatory asset. In 2011, this regulatory asset decreased by $23 million (2010 - increased by $2 million) to reflect a revaluation adjustment in the Company's PCB liability. There was no change in the land assessment and remediation (LAR) liability (2010 –$1 million decrease). The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $23 million (2010 - higher by $1 million). In addition, amortization expense in 2011 would have been lower by $8 million (2010 - $9 million) and financing charges would have been higher by $8 million (2010 - $8 million).

Pension Cost Variance

The pension cost variance account was established to track the difference between the actual pension costs incurred by the Distribution Business and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension contributions paid compared to OEB-approved amounts. In the absence of rate-regulated accounting, revenue would have been lower by $13 million in 2011 (2010 - $12 million).

Rider 2 or Regulatory Asset Recovery Account II (RARA II)

As part of a 2006 distribution rate decision, the OEB approved the recovery of several distribution-related deferral account balances sought by the Company. RARA II includes retail settlement and cost variance amounts, distribution low-voltage service amounts and accrued interest. In the absence of rate-regulated accounting, amortization expense would have been lower by $8 million in 2010.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of the Company's Distribution Business who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to the Company in respect of the Distribution Business and the fixed entitlements defined in the regulation, and subsequent OEB rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

Rider 4 or Revenue Recovery Account

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business. The approved rates were effective May 1, 2008 with an implementation date of February 1, 2009. The OEB approved the establishment of Rider 4 to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009 and ending April 30, 2011.

Regulatory Liabilities

Rider 8

As part of its April 9, 2010 rate decision, the OEB required the establishment of deferral accounts to capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received.

Retail Settlement Variance Accounts (RSVA)

The Distribution Business has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. Hydro One Networks has accumulated a net liability in its RSVAs since December 31, 2009.

Rider 3 or RLRA

The OEB's December 18, 2008 decision approved certain distribution-related deferral account balances sought by the Company in its application including RSVA amounts, deferred impact of tax rate changes, OEB costs and smart meter amounts. Amounts approved for recovery represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

PST savings deferral

The Company is required to record the impact from the implementation of an HST sales tax regime on July 1, 2010. The variance amounts recognized in the account reflect Provincial Sales Tax (PST) amounts in approved revenue requirements after the implementation of the HST. These amounts will be refunded to ratepayers in future years.

Rider 6

As part of the April 9, 2010 rate decision, the OEB approved for disposal certain distribution-related deferral account balances, including retail settlement variance accounts, the Regulatory Asset Recovery Account I, retail cost variance accounts and smart meter amounts. The OEB ordered that the balances approved for recovery be aggregated into a single regulatory account (Rider 6) to be recovered over a 20-month period from May 1, 2010 to December 31, 2011.

9. DEBT

Debt represents the Distribution Business' share of various notes payable by Hydro One Networks to Hydro One.

December 31 (Canadian dollars in millions)	**2011**	**2010**
Long-term debt	2,880	2,831
Add: Unrealized marked-to-market loss[1]	9	2
Less: Long-term debt payable within one year	(324)	(176)
Net unamortized premiums	11	12
Unamortized debt issuance costs	(11)	(11)
	2,565	2,658

[1] The unrealized marked-to-market loss relates to the $100 million note which matured March 3, 2011; $100 million of the $175 million note maturing November 19, 2014 and $100 million of the $200 million note maturing September 11, 2015, which are accounted for as fair value hedges. The unrealized marked-to-market loss is offset by a $9 million (2010 - $2 million) unrealized gain on the related fixed-to-floating interest rate swap agreements.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 10.

10. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2011 is as follows:

(Canadian dollars in millions)	**Derivatives Used for Hedging**	**Other Financial Instruments Used for Hedging**	**Loans and Receivables**	**Other Financial Assets and Liabilities**
Financial Assets				
Inter-company demand facility	-	-	-	141
Accounts receivable	-	-	744	-
Other assets	9	-	-	-
Financial Liabilities				
Accounts payable and accrued charges[1]	-	-	-	641
Long-term debt	-	209	-	2,680

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Distribution Business, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)	**2011**		**2010**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	2,880	3,389	2,831	3,114

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the amounts which are designated as part of a hedging relationship.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although Hydro One could in the future decide to issue foreign currency denominated debt which could be mirrored through parental issuance to the Company. This debt will be hedged back to Canadian dollars consistent with Hydro One's risk management policy. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution Business is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30 year "A" rated Canadian utility bonds over the 30 year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield or the "A" rated Canadian utility spread used in determining the Company's rate of return would reduce its Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2011, there was no significant balance of accounts receivable due from any single customer.

In the year, the Distribution Business' provision for bad debts was $15 million (2010 - $22 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2011, approximately 3% of the Distribution Business' accounts receivable were aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques, including entering into transactions with highly rated counter-parties, limiting total exposure levels with individual counterparties consistent with Hydro One's Board-approved Credit Risk Policy, entering into master agreements which enable net settlement and the contractual right of offset, and monitoring the financial condition of counterparties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Balance Sheets.

Hydro One uses derivative financial instruments to manage interest rate risk. Hydro One, and the Company, may enter into derivative agreements such as forward interest rate agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. No such agreements were outstanding as at December 31, 2011.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through the inter-company demand facility from Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2011, accounts payable and accrued charges in the amount of $641 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next twelve months is $324 million. Interest payments over the next twelve months on the Distribution Business' outstanding debt amount to $150 million.

As at December 31, 2011, the Distribution Business' share of the long-term debt of Hydro One Networks to Hydro One is $2,880 million and the required future interest payments are $2,408 million. Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Interest Payments (*Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	324	150	5.8
2 years	230	131	5.0
3 years	175	120	3.2
4 years	220	114	2.9
5 years	180	104	4.7
	1,129	619	4.5
6 – 10 years	315	450	4.9
Over 10 years	1,436	1,339	5.9
	2,880	2,408	5.2

NOTES TO FINANCIAL STATEMENTS (continued)

11. CAPITAL MANAGEMENT

The Distribution Business's objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB as being appropriate for all distributors in its December 20, 2006 Cost of Capital Report. This deemed capital structure is 60% debt and 40% common equity.

The Distribution Business considers its capital structure to consist of excess assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

(Canadian dollars in millions)	**2011**	**2010**
Long-term debt payable within one year	324	176
Less: Inter-company demand facility	141	86
	183	90
Long-term debt	2,565	2,658
Excess of assets over liabilities	2,168	1,976
Total capital	4,916	4,724

12. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Inc. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new employees represented by the Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario in September 2010, effective for December 31, 2009, Hydro One contributed $152 million to its pension plan in respect of 2011 (2010 - $193 million), $148 million of which is required to satisfy minimum funding requirements (2010 - $145 million). Hydro One made an additional payment of $48 million in December 2010 and an additional payment in 2011 related to a partial plan wind-up of $4 million. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Future contributions will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2011 of the accrued pension benefits, based on a projection of the valuation at December 31, 2011, was estimated to be $5,461 million (2010 - $4,996 million). Pension plan assets available for these benefits were $4,682 million (2010 - $4,699 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2011, $33 million of employee future benefits other than pension costs were charged to the results of operations of the Distribution Business (2010 - $28 million), and $23 million was capitalized as part of the cost of fixed and intangible assets (2010 - $19 million). Benefits paid were $23 million (2010 - $23 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2011 was $598 million (2010 - $565 million), including the current portion.

A detailed description of employee future benefits is provided in Note 12 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2011.

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	Polychlorinated Biphenyls (PCB)	Land Assessment and Remediation (LAR)	Total
2011			
Environmental liabilities, January 1	135	31	166
Interest accretion	7	1	8
Expenditures	(3)	(5)	(8)
Revaluation adjustment	(23)	-	(23)
Environmental liabilities, December 31	116	27	143
Less: current portion	5	4	9
	111	23	134
2010			
Environmental liabilities, January 1	130	36	166
Interest accretion	7	1	8
Expenditures	(4)	(5)	(9)
Revaluation adjustment	2	(1)	1
Environmental liabilities, December 31	135	31	166
Less: current portion	5	4	9
	130	27	157

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $9 million; 2013 - $9 million; 2014 - $22 million; 2015 - $19 million; 2016 - $18 million and thereafter - $89 million. Of the total estimated future expenditures, $138 million relate to PCB (2010 - $156 million) and $28 million to LAR (2010 - $33 million).

Consistent with the Company's accounting policy for environmental costs, the Distribution Business records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009. However, in 2009, the Company sought and received an extension until 2014 for the removal of PCBs from certain station equipment that could potentially be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with replacement oil that is less than 2 ppm.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Distribution Business' environmental liabilities represent management's best estimates of the present value cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Distribution Business' current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when the obligations were first recorded.

14. ASSET RETIREMENT OBLIGATIONS

Consistent with its accounting policy for asset retirement obligations, Hydro One Networks records a liability for the present value of the estimated future expenditures associated with the retirement of tangible long-lived assets that it is legally required to remove. A corresponding amount is recorded as an asset retirement cost that is capitalized as part of the carrying amount of the related fixed asset.

The Company has recorded a liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The Company's liability is based on management's best estimate of the present value of the estimated future expenditures to comply with existing regulations. In 2010, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The present value of the estimated future expenditures is $3 million. The amount of interest recorded is nominal and there have been no expenditures associated with this obligation.

There are uncertainties in estimating future expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.
In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

15. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of preferred shares and common shares.

16. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of the Company and its Distribution Business. In addition, the OEB is related by virtue of its status as a Provincial Crown Corporation. The OEB is a self-financing and self-sufficient regulatory organization that carries out independent regulation for Ontario's energy sector, including Hydro One's regulated Distribution Business. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business received amounts for rural rate protection from the IESO. Revenues include $125 million related to this program in each of 2011 and 2010. In 2011, the Distribution Business purchased power in the amount of $2,057 million (2010 - $2,042 million) from the IESO-administered electricity market, $16 million (2010 - $19 million) from OPG and $10 million (2010 - $13 million) from the OEFC.

Under the Ontario *Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2011, the Distribution Business incurred $7 million (2010 - $7 million) in OEB fees.

The Company has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs related to the purchase of services from these successor corporations were less than $1 million in each of 2011 and 2010.

The OPA funds some of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives and management fees and bonuses. In 2011, the Distribution Business received $38 million (2010 - $30 million) from the OPA in respect of the CDM programs. Revenues include $3 million of unregulated incentive revenue from the OPA in respect of CDM programs in both 2011 and 2010.

The PILs, property taxes and capital taxes of the Distribution Business were paid or payable by the Company to the OEFC (Note 5).

Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues of the Distribution Business include $2 million (2010 - $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Distribution Business include $10 million (2010 - $8 million) related to the purchase of services from Hydro One and its subsidiaries.

The Company's debt, including the portion allocated to the Distribution Business, is due to Hydro One. Financing charges of the Distribution Business include interest expense on this debt in the amount of $152 million (2010 - $150 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business are net of interest earned on this facility in the amount of $2 million (2010 - $1 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2011**	**2010**
Accounts receivable	23	1
Accounts payable and accrued charges	(237)	(208)

Included in accounts payable and accrued charges are amounts owing to the IESO, OEFC, OPG in respect of power purchases of $182 million (2010 - $193 million).

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Accounts receivable increase	(31)	(40)
Materials and supplies decrease	1	1
Accounts payable and accrued charges increase	131	63
Accrued interest increase	-	3
Long-term accounts payable and other liabilities decrease	-	(1)
Employee future benefits other than pension increase	33	22
Other	(6)	10
	128	58

Supplementary information:		
Interest paid	152	149
Payments in lieu of corporate income taxes	31	16

18. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Company's Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of the Company and Hydro One.

19. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

20. SUBSEQUENT EVENTS

On January 13, 2012, Hydro One issued $300 million in 3.20% notes under its MTN program with a maturity date of January 13, 2022. On the same date, Hydro One Networks issued 3.22% notes payable to Hydro One in the amount of $280 million, with the same maturity date. The Distribution Business' share of the offering was $126 million.

On March 23, 2012, the OEB approved Hydro One Networks' request to adopt US GAAP as the basis for regulatory accounting and reporting in its Distribution Business, consistent with an earlier approval given to its Transmission Business. This decision aligns Hydro One Networks' regulatory reporting framework with that approved for Hydro One Inc..

21. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2011 Financial Statements.

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RECENT RATING AGENCY REPORTS

Included in this Exhibit are copies of the most recent rating agency reports performed by Moody's Investor Service and Standard & Poor's.

Attachment 1: Standard & Poor's, Research Update dated: April 25, 2012
Attachment 2: Moody's Investor Service, Global Credit Research dated: April 27, 2012

STANDARD
&POOR'S

Standard & Poor's Research

April 25, 2012

Research Update:

Hydro One Inc. Outlook To Negative From Stable Following Outlook Revision On Ontario

Primary Credit Analyst:
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Research Update:

Hydro One Inc. Outlook To Negative From Stable Following Outlook Revision On Ontario

Overview

- We are revising our outlook on Hydro One Inc. to negative from stable.
- We are also affirming our ratings, including our 'A+' long-term corporate credit rating, on Hydro One.
- The outlook revision reflects that on the Province of Ontario.
- Despite the revision, our view that there is a "high" likelihood that the province would provide timely and sufficient extraordinary support in the event of financial distress has not changed.

Rating Action

On April 25, 2012, Standard & Poor's Ratings Services revised its outlook on electricity transmitter and distributor Hydro One Inc. to negative from stable. At the same time, Standard & Poor's affirmed its ratings, including its 'A+' long-term corporate credit rating on Hydro One.

The outlook revision reflects the outlook revision on the utility's owner, the Province of Ontario (AA-/Negative/A-1+), to negative from stable April 25, 2012. (For more information, see "Province of Ontario Outlook Revised To Negative From Stable On Risks To Fiscal Plan," published April 25, 2012, on RatingsDirect on the Global Credit Portal.) However, despite the outlook revision, our view that there is "high" likelihood the province would provide timely and sufficient extraordinary support in the event of financial distress has not changed.

Rationale

The ratings on Hydro One reflect Standard & Poor's opinion of the company's low-risk monopoly electricity transmission and distribution assets; secure and relatively predictable regulated cash flows; and the support of its owner, the province. We believe the utility has an excellent business risk profile and view its financial risk profile as significant on our expanded risk matrix. The company had C$8.0 billion in reported total debt outstanding as of Dec. 31, 2011.

We base our 'A+' rating on Hydro One on our assessment of the company's stand-alone credit risk profile (SACP) of 'a' and our opinion that there is a "high" likelihood that the province would provide timely and sufficient extraordinary support in the event of financial distress. We view the company's role as "important" to the province and the link between it and the province as "very strong."

In our view, Hydro One has a significant financial risk profile. We believe its cash flow strength relative to its debt obligations has weakened in the past few years due to a material capital expenditure program. The company's annual capital expenditures were C$1.5 billion in 2010 and 2011, exceeding its internal cash flow generation (C$1.1 billion in adjusted funds from operations [AFFO] in both 2010 and 2011). Because Hydro One has budgeted annual capital expenditures of about C$1.8 billion in each of the next two years, we believe that it will continue to face significantly sizable negative free operating cash flow in the next few years.

Liquidity

The short-term rating on Hydro One is 'A-1'. We believe the company has adequate liquidity to cover its needs in the near term, even in the event of unforeseen earnings declines. Standard & Poor's assessment incorporates the following expectations and assumptions:

- Hydro One's liquidity sources, including liquid short-term investments, FFO, and credit facility availability, will likely exceed its uses 1.2x or more in the next 12 months.
- Liquidity sources include an expectation of about C$1.3 billion of FFO, access to C$1.25 billion of the company's committed revolving credit facility with a syndicate of banks, and C$228 million liquid short-term investments as of Dec. 31, 2011. The C$1.25 billion credit facility was fully available as of Dec. 31, and will expire in June 2014. Hydro One remains well within its banking covenant of 75% total debt-to-total capital.
- Liquidity uses include C$600 million of maturing debt in 2012, an estimated dividend payment of approximately C$300 million, and about C$1.8 billion of capital expenditures, of which about C$400 million is discretionary.
- The company has what we consider good relationships with its banks and good standing in the debt market. We understand that the utility also holds a C$250 million note issued by the province that matures in 2014, which it could liquidate if needed. It could also reduce its dividend payment to help satisfy its cash requirements. The company's debt maturities are well spread, in our view, with annual scheduled repayment in the next six years averaging about C$600 million.

Hydro One provides the Independent Electricity System Operator (IESO) with C$325 million in parental guarantees in lieu of prudential support. If all the ratings on the utility were to fall, the IESO's prudential requirements would likely increase.

Outlook

The negative outlook reflects the outlook revision on Ontario. Based on our criteria for government-related entities, given a high likelihood of extraordinary support, an 'a' SACP for Hydro One and our 'AA-' rating on the province, a one- or two-notch downgrade on the province would affect the ratings on Hydro One, but likely not more than one notch given the company's underlying credit strength. We still consider Hydro One's performance to be consistent and expect continued predictable regulatory support despite its large capital expenditure program and negative free operating cash flows. In the event of lower-than-expected cash flows and earnings, we expect the company to maintain its leverage within the deemed capital structure of 60% reported debt-to-capital, AFFO-to-debt of about 12%, and AFFO interest coverage of about 3x, by curtailing its capital spending and additional debt financing. In our view, there is no cushion for Hydro One to deteriorate from our expectations on its key credit measures to maintain the ratings. A material adverse regulatory ruling or market restructuring (such as the assumption of the obligation to supply, not just deliver, electricity), or any deterioration of financial measures beyond our expectation, could lead us to lower the existing 'a' SACP and consequently the ratings, regardless of any changes to Ontario. An improvement in the company's SACP is unlikely without the assurance of a much stronger balance sheet, and deeper cash flow-interest and debt coverage. A change in the relationship with the province that leads us to reconsider the likelihood of Hydro One receiving support could also move the ratings.

Related Criteria And Research

- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009

Ratings List

Outlook Revised To Negative

	To	From
Hydro One Inc.		
Corporate credit rating	A+/Negative/A-1	A+/Stable/A-1

Ratings Affirmed

Hydro One Inc.	
Senior unsecured debt	A+
Commercial paper	
Global scale	A-1
Canada scale	A-1(Mid)

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

MOODY'S INVESTORS SERVICE

Rating Action: Moody's downgrades Hydro One to A1, outlook stable

Global Credit Research - 27 Apr 2012

Toronto, April 27, 2012 -- Moody's Investors Service has downgraded Hydro One Inc.'s senior unsecured rating to A1 from Aa3, and affirmed its P-1 short term rating. The Baseline Credit Assessment (BCA) was also affirmed at 8 (Baa1), together with high default dependence and high probability of support from the Province of Ontario ("Province"). The outlook for the long term rating is stable. Moody's notes that this rating action is being taken in conjunction with the downgrade of the Province's senior unsecured rating to Aa2, outlook stable, from Aa1, outlook negative. At the same time, this rating action reflects Moody's assessment that the improving financial metrics for Hydro One, cited as the basis for maintaining a stable outlook in December, 2011 when the outlook for the Province was changed to negative, are now likely to level off below measures Moody's anticipated.

RATINGS RATIONALE

Hydro One's A1 senior unsecured rating is a reflection of a Baseline Credit Assessment (BCA) of 8 (Baa1on a scale of 1-21, where 1 represents the equivalent risk of an Aaa, 2 an Aa1, 3 an Aa2 and so on) together with Moody's expectation of high default dependence and high probability of support from the Province of Ontario (Aa2). Hydro One's BCA of 8 is primarily driven by Moody's view that Hydro One is a well managed business with a deliverable business strategy that should not be unduly affected by the economic challenges facing the Province. However, slow growth expectations for the provincial economy and the Province's energy policy implications for Hydro One's capital expenditures do have an impact on financial performance and have stalled the improving metrics although the overall result remains a BCA of 8. At the same time, Moody's remains cognizant of the close linkage Hydro One has to the Province, as reflected in the uplift to Hydro One's rating, and the possibility that the Province's actions to address budget challenges may impact Hydro One's capital expenditures or dividend policy, either of which could have a negative effect on the financial performance of Hydro One.

WHAT COULD CHANGE THE RATING UP/DOWN

A change in the rating or outlook for the Province would put pressure, either up or down, on Hydro One's rating. Likewise, changes in government policy that would materially affect dividends, capital expenditures or revenue for Hydro One would affect the financial metrics although we would not expect there to be sufficient movement to move the overall rating in either direction.

The methodologies used in this rating were Regulated Electric and Gas Utilities published in August 2009, and Government-Related Issuers: Methodology Update published in July 2010.Please see the Credit Policy page on www.moodys.com for a copy of these methodologies.

Headquartered in Toronto, Ontario, Hydro One is a commercial corporation, 100% owned by the Province of Ontario. Virtually all of Hydro One's revenues and cash flows are derived from its electricity transmission and distribution businesses, both of which are regulated by the Ontario Energy Board (OEB). Hydro One owns and operates virtually all of Ontario's electricity transmission system and a substantial portion of the province's electricity distribution assets.

REGULATORY DISCLOSURES

Although this credit rating has been issued in a non-EU country which has not been recognized as endorsable at this date, this credit rating is deemed "EU qualified by extension" and may still be used by financial institutions for regulatory purposes until 30 April 2012. Further information on the EU endorsement status and on the Moody's office that has issued a particular Credit Rating is available on www.moodys.com.

For ratings issued on a program, series or category/class of debt, this announcement provides relevant regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides relevant regulatory disclosures in relation to the rating action on the support provider and in relation to each particular rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides relevant regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

Information sources used to prepare the rating are the following : parties involved in the ratings, parties not involved in the ratings, public information, and confidential and proprietary Moody's Investors Service information.

Moody's considers the quality of information available on the rated entity, obligation or credit satisfactory for the purposes of issuing a rating.

Moody's adopts all necessary measures so that the information it uses in assigning a rating is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

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Please see the ratings disclosure page on www.moodys.com for information on (A) MCO's major shareholders (above 5%) and for (B) further information regarding certain affiliations that may exist between directors of MCO and rated entities as well as (C) the names of entities that hold ratings from MIS that have also publicly reported to the SEC an ownership interest in MCO of more than 5%. A member of the board of directors of this rated entity may also be a member of the board of directors of a shareholder of Moody's Corporation; however, Moody's has not independently verified this matter.

Please see Moody's Rating Symbols and Definitions on the Rating Process page on www.moodys.com for further information on the meaning of each rating category and the definition of default and recovery.

Please see ratings tab on the issuer/entity page on www.moodys.com for the last rating action and the rating history.

The date on which some ratings were first released goes back to a time before Moody's ratings were fully digitized and accurate data may not be available. Consequently, Moody's provides a date that it believes is the most reliable and accurate based on the information that is available to it. Please see the ratings disclosure page on our website www.moodys.com for further information.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

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PROPOSED PUBLICATIONS FOR NOTICE

Attached is the list of newspapers in which the Board's Notice of Application for the EB-2009-0096 proceeding was published. Hydro One would like to discuss with Board staff the potential to reduce the number of newspapers in which the Notice for this Application must be published in, possibly by use of other social media outlets in order to reduce costs and provide a more efficient means of communication.

EB 2012-0136- COMPLETE NEWSPAPER LIST	Category	Language
Atikokan Progress	Weekly	English
Barrie Examiner	Daily	English
Belleville Intelligencer	Daily	English
Brantford, The Expositor	Daily	English
Fort Francis Times	Daily	English
Globe and Mail (Ontario)	Daily	English
Guelph Mercury	Daily	English
Hamilton Spectator	Daily(Mon-Thurs)	English
Kingston Whig-Standard	Daily	English
Kitchener Record	Daily (Mon-Thurs)	English
Niagara Falls Review	Daily	English
Peterborough Examiner	Daily	English
Sarnia Observer	Daily	English
Sault Ste. Marie Star	Daily	English
Simcoe Reformer	Daily	English
St. Catharines Standard	Daily	English
Stratford Beacon Herald	Daily	English
Sudbury Star	Daily	English
Thunder Bay Chronicle Journal	Daily	English
* Thunder Bay Chronicle Journal	"	French
Timmins, The Daily Press	Daily	English
Toronto Star (Section A,GTA)	Daily	English
Welland Tribune	Daily	English
Woodstock Sentinel	Daily	English
Brockville Recorder	Daily	English
Chatham Daily News	Daily	English
Cornwall Le Journal	Weekly	French
Kenora Daily Miner and News	Daily	English
Le Reflet (Prescott Russell)	Weekly	French
Marathon Mercury	Weekly	English
* Marathon Mercury	"	French
Pembroke Observer	Daily	English
Rainy River Record	Weekly	English
Sioux Lookout Bulletin	Weekly	English
St. Thomas Times Journal	Daily	English
Sturgeon Falls West Nipissing Tribune	Weekly	English
* Sturgeon Falls West Nipissing Tribune	"	French
Terrace Bay Schreiber News	Weekly	English
* Terrace Bay Schreiber News	"	French
Toronto L'Express	Weekly	French
Aylmer Express	Weekly	English
Barry's Bay This Week	Weekly	English
Bracebridge Examiner	Weekly	English
Clinton News Record	Weekly	English
Dryden Observer	Weekly	English
Elliot Lake The Standard	Weekly	English
Essex Free Press	Weekly	English
Geraldton Times Star	Weekly	English
Hamilton Le Regional	Weekly	French
Hawkesbury Le Carillon	Weekly	French
Hearst/Kapuskasing Le Nord	Weekly	French
Huntsville Forester	Weekly	English
Ignace Driftwood	Weekly	English
* Ignace Driftwood	"	French

EB 2012-0136- COMPLETE NEWSPAPER LIST	Category	Language
Le Metropolitain (Toronto-Brampton)	Weekly	French
Listowel Banner	Weekly	English
London L'action	Weekly	French
Manitouwadge Echo	Weekly	English
* Manitouwadge Echo	"	French
Ohsweken Turtle Island News (First Nation)	Weekly	English
Parry Sound North Star	Weekly	English
Red Lake Northern Sun News	Weekly	English
Sudbury Le Voyageur	Weekly	French
Thessalon North Shore Sentinel	Weekly	English
* Thessalon North Shore Sentinel	"	French
Timmins Les Nouvelles	Weekly	French
Vankleek Hill Review	Weekly	English
Walkerton Herald Times	Weekly	English
Wawa Algoma News Review	Weekly	English
Winchester Press	Weekly	English
Windsor Le Rempart	Weekly	French
Arnprior Chronicle-Guide	Weekly	English
Bancroft Times	Weekly	English
Brighton Independent	Weekly	English
Cambridge Times	Community	English
Cochrane Times-Post	Weekly	English
Cornwall, Standard-Freeholder	Daily	English
Kapuskasing The Weekender	Weekly	English
* Kapuskasing The Weekender	"	French
London Free Press	Daily	English
North Bay Nugget	Daily	English
Northumerland today	Weekly	English
Orangeville Banner	Weekly	English
Orillia Packet and Times	Daily	English
Ottawa Citizen	Daily	English
Ottawa Le Droit	Daily	French
Owen Sound, The Sun Times	Daily	English
Penetanguishene Le Gout De Vivre	Semi-monthly	French
Perth Courier	Weekly	English
Picton Gazette	Weekly	English
Strathroy Age Dispatch	Weekly	English
Windsor Star	Daily	English
Brampton Guardian	Weekly	English
* Brampton Guardian	"	French
Clarence-Rockland Vision	Weekly	English
* Clarence-Rockland Vision	"	French
Kirkland Lake Northern Daily News	Daily	English
Lindsay Daily Post	Weekly	English
Mississauga News	Weekly	English
* Mississauga News	"	French
New Liskeard Temiskaming Speaker's Weekender	Weekly	English
Oshawa/Whitby/Clarington This Week (Eng)	Weekly	English
Sioux Lookout Wawatay News	Semi-monthly	English

PROCEDURAL ORDERS – CORRESPONDENCE - NOTICES

To be filed behind this tab as and when Procedural Orders, Correspondence and Notices are filed.