Building Owners and Managers Association Toronto Interrogatory # 62

Issue:

[Issue Group]

Reference:

A-03-01-05

Interrogatory:

Please confirm that Hydro One Networks Inc., Hydro One Inc., and Hydro One Limited are OBCA or CBCA incorporated companies. Are they all OBCA?

Response:

Hydro One Networks, Hydro One Inc. and Hydro One Limited are OBCA incorporated companies.

Witness: LOPEZ Chris

Building Owners and Managers Association Toronto Interrogatory # 64

Issue:
[Issue Group]

Reference:
A-03-01-05 Page: 15

Interrogatory:
Custom IR proceedings are intended to be framed more like performance inquiries resulting in multi-year outcome commitments and measures that facilitate year-over-year performance assessment.

Response:
Hydro One notes that this interrogatory poses no question.

Balsam Lake Coalition Interrogatory # 1

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

Previous Proceeding
EB-2013-0416/EB-2015-0079, Decision dated December 22, 2015
EB-2016-0315, Procedural Order No. 1 dated November 3, 2016 (as corrected)

Interrogatory:

a) What steps, if any, has Hydro One taken subsequent to the Board's decision EB-2013-0416/EB-2015-0079 dated December 22, 2015 to comply with the Board's order to eliminate the Seasonal Rate class?

b) Please provide any information provided to Hydro One from the OEB with respect to taking steps towards the elimination of the Seasonal Rate class beyond the transition to fully fixed rates in the EB-2015-0079 decision, including but not limited to the continuation of the EB-2016-0315 proceeding.

c) Please confirm that all of Hydro One's rates continue to be interim effective November 3, 2016 pursuant to the Procedural Order No. 1 in EB-2016-0315 dated November 3, 2016 (as corrected). If not confirmed, please provide the OEB order making rates subsequent to November 3, 2016 final.

Response:

a) Subsequent to the Board's decision in EB-2013-0416/EB-2015-0079 dated December 22, 2015 Hydro One prepared a "Report on the Elimination of the Seasonal Class" that was filed with the OEB on August 4, 2015. On September 30, 2015 the OEB issued an Order requiring Hydro One to apply the OEB's policy on distribution rate design (i.e. move to all-fixed rates) for residential customers to its Seasonal class, which Hydro One did in setting 2016 and 2017 distribution rates, and has proposed in this current application. On November 3, 2016 the OEB issued Procedural Order #1 (PO#1), corrected on November 10, for a new OEB-initiated proceeding EB-2016-0315 to consider the remaining steps for elimination of the Seasonal class. On December 1, 2016, in response to PO#1, Hydro One provided an update to the August 4, 2015 Report that addressed the items raised in PO#1, and also filed a draft Notice of Proceeding as requested.

b) Please see the response to Exhibit I-16-CCC-17 for an email exchange with Board staff seeking clarification on information provided in the updated report.

c) Confirmed.

Building Owners and Managers Association Toronto Interrogatory # 1

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-02-01 Page: 1-49

Interrogatory:

What conclusions has Hydro One drawn from the Total Factor Productivity Study and what if any changes has it made to its operations as a result?

Response:

The Total Factor Productivity ("TFP") Study has, among other things, concluded that Hydro One's overall internal productivity has improved in recent years. Further details can be found in the report. The conclusions in the TFP study are also consistent with the results of the PSE's Total Cost Benchmarking study (Exhibit A, Tab 3, Schedule 2, Attachment 2) which shows an improvement in cost performance relative to Hydro One's peers and has resulted in an improvement to Hydro One's assigned stretch factor cohort. Combined, these studies show the improvements that Hydro One has been making in the efficiency of its operations. The Total Factor Productivity study was used to inform Hydro One's proposed Revenue Cap Index, as described in Exhibit A, Tab 3, Schedule 2.

Building Owners and Managers Association Toronto Interrogatory # 2

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

C1-02-01-07 Page: 1

Interrogatory:

Has Hydro One benchmarked its compensation to comparable companies? If so which and what are the results?

Response:

Please refer to the Mercer Total Compensation Study provided as Attachment 5 to Exhibit C1, Tab 2, Schedule 1.

Building Owners and Managers Association Toronto Interrogatory # 3

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

C1-02-01

Interrogatory:

Prior to the break-up of Ontario Hydro, vegetation management was a significant program for the Distribution System Division. When was vegetation management program reduced and what were the impacts of doing so on reliability?

Response:

The vegetation management program remains a major component of Hydro One's distribution maintenance budget, accounting for over 43% of the total Sustaining OM&A budget as documented in Table 1 of Exhibit C1, Tab 1, Schedule 2. Furthermore the historical year over year spending on the vegetation management program has been on an upward trend. Despite an increasing budget, tree contact reliability trends have been increasing (as noted in Table 13 and Table 14 in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4) and this correlation is one of the major drivers of the change in vegetation management approach outlined in Exhibit Q, Tab 1 Schedule 1.

Building Owners and Managers Association Toronto Interrogatory # 40

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Internal Audit Report of Auditor General – Final Report of Internal Auditor, March 31, 2017

Interrogatory:

a) Auditor General ("AG") had seventeen specific issues for Hydro One. How many of the AG's actions did Hydro One accept as valid and requiring action?

b) What are the thirty-seven actions that it corrected, and show which AG recommendation each of the thirty-seven actions related to. What were the seventy-one corrected actions that HONI corrected (p2), and how do they relate to the thirty-seven actions mentioned at p1 and which AG's report engaged; which ones are now accepted, and which are outstanding? Please confirm their description with Appendix A for each of the AG's seventeen recommendations.

Response:

a) Hydro One's responses and actions pertaining to the Auditor General's seventeen recommendations are included in the published Auditor General's 2015 Annual Report.

b) Please refer to Exhibit I-3-SEC-7.

Building Owners and Managers Association Toronto Interrogatory # 41

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A Page: 3

Interrogatory:

a) Please provide the cost benefit analysis of planned maintenance activities conducted by Planning, and indicate why, as noted by the AG, the results were not used in the 2018 Investment Plan.

b) Why were multi-year reliability targets not established?

c) What was the reliability target for 2017? Was it met?

Response:

a) The AG's finding in question relates to AG Recommendation #1 which is in reference to the cost benefit analysis of the planned maintenance activities for Hydro One Transmission, and therefore not relevant to the distribution rate filing.

b) Multi-year distribution reliability targets have been established; please refer to interrogatory response Exhibit I-18-SEC-29.

c) The transmission reliability target for 2017 was met but it is not relevant to this proceeding.

Building Owners and Managers Association Toronto Interrogatory # 42

Issue:
Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:
A-03-01-03 Appendix A Page: 4

Interrogatory:
a) Please describe the backlog of preventative maintenance, the plan to deal with it, the time that will take, the costs of doing so, and the cost of keeping ongoing maintenance schedule current. Are the costs in the five year budget and distribution investment plan?

b) Please provide a copy of the Work Governance Agreement, referred to.

Response:
a) Hydro One Distribution does not consider there to be a backlog of preventive maintenance work.

b) This request pertains to Hydro One Transmission business not to Hydro One Distribution, and therefore not relevant to the distribution rate filing.

Building Owners and Managers Association Toronto Interrogatory # 43

Issue:
Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:
A-03-01-03 Appendix A Page: 3

Interrogatory:
What was Hydro One's reply to the AG's claim that assets in good condition were replaced before assets in poor or very poor condition? What are the statistics for each type of asset over each of the last three years? What, if any, is management commitment going forward? Please provide a description of each instance in 2015, 2016, and 2017 where an asset now in poor or very poor condition was replaced, and the reasons for that specific decision.

Response:
None of the AG’s recommendations highlight a concern regarding Hydro One replacing distribution assets in good condition before assets in poor or very poor condition. The AG’s finding in question relates to AG Recommendation #3 (please refer to Exhibit A, Tab 3, Schedule 1, Attachment 3, Appendix A, page 4) which is in reference to Hydro One Transmission’s assets not Hydro One Distribution’s assets and therefore not relevant to the distribution rate filing.

Building Owners and Managers Association Toronto Interrogatory # 44

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A Page: 4

Interrogatory:

Did Hydro One agree with the AG's assertion that the OEB was misled in prior years about (annual) replacement activities?

Response:

No, Hydro One does not agree with this assertion. The AG finding related to the replacement activities referenced on page 4 of Exhibit A, Tab 3, Schedule 1, Attachment 3, Appendix A is with regards to AG Recommendation #4 which relates to Hydro One Transmission's assets and therefore not relevant to the distribution rate filing.

Building Owners and Managers Association Toronto Interrogatory # 45

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A AG: 6

Interrogatory:

Please explain the purpose, and terms of reference for the Data Governance Project. How will the report address the shortcomings in data analytics pointed out by AG, in particular, with respect to HONI distribution? Please provide copies of the report, if completed. Have results been used in this filing?

Response:

Data governance provides the framework to continuously improve data quality and completeness. There is no Data Governance report; however, a Data Governance project is currently underway.

The Data Governance project, as noted in AG #11 for Hydro One distribution assets, was to provide data completeness improvements where missing data exists, review data requirement needs, and to clarify ongoing accountability, processes and communication to monitor and remedy data issues.

Hydro One is currently addressing the data analytics shortcomings. Data requirements have been identified and remediation activities are scheduled to be completed in 2018.

Yes, the results carried out in 2016 were used in this filing.

Building Owners and Managers Association Toronto Interrogatory # 46

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A AG: 7

Interrogatory:

Please provide copies of the company's past maintenance expenditures with reliability performance by planning optimization. When will the results be incorporated into the DSP? Please provide a status report on the state of development preventative maintenance plan (see transmission decision).

Response:

The AG’s recommendation in question (AG 7) is related to Hydro One’s transmission system reliability and therefore not relevant to this distribution rate filing.

Building Owners and Managers Association Toronto Interrogatory # 48

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A AG: 10

Interrogatory:

Is there a study on this matter?

Response:

Please refer to Attachment 2 of section 1.6 of the DSP (Exhibit B1, Tab 1, Schedule 1) for the *Hydro One Vegetation Management Study 2016* by CN Utility Consulting, Inc. and Attachment 2 of Exhibit Q, Tab 1, Schedule 1 for the *Hydro One – Forestry Survey Assessment* report by Clear Path Utility Solutions, LLC.

Building Owners and Managers Association Toronto Interrogatory # 49

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A AG 11, Page: 8

Interrogatory:

When will the quality of distribution data be addressed?

Response:

Data quality improvement is an ongoing activity and will require ongoing focus and continuous improvement.

Witness: BRADLEY Darlene

Building Owners and Managers Association Toronto Interrogatory # 50

Issue:
Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:
A-03-01-03 Appendix A AG 14

Interrogatory:
Please provide a summary of the Project Charter for the AMIA project. When will the results be available?

Response:
The Advanced Metering Infrastructure for Analytics (AMIA) project built a system that relates operational data with other data (meter, asset, customer, etc.) and provides an ability to perform analytics against the integrated "big data" set.

The project sourced, integrated and stored enterprise data in an efficient "big data" infrastructure and provisioned the query and data extraction needed to perform the following business use cases:

Use Case	Description
Load Analytics	Provides hourly kWh profiles for all transformers on the network.
Feeder Analysis	Provides hourly kWh profiles for all transformers on the network.
DMS Profiles	Provides normalized profiles for mass market customers and average load profiles for large commercial/industrial customers.
High Usage Bill Alerts	Provides data integration for the system to provide customers insights into the electricity usage.
Home Energy Dashboards	Provides data integration for the system that alerting customers when they are consuming above normal electricity.

Along with these specific use cases, the AMIA solution is provided the following benefits to Hydro One:

1. An integrated and consistent store of operational, transactional, and analytical data used for decision-making:
    a) Centralized/single point of data source integration (i.e., ‘touch once’)
    b) Optimized storage and architected for performance
    c) Architected and managed environment
    d) Available to all lines of business, as required
    e) Reusable and leverages existing Hydro One investments
    f) Ability to integrate multiple data sources (internal and external)
2. An adaptable and extensible technical environment to support future business requirements;
3. An efficient and economic storage structure with near-time access to many years of operational and transactional data;
4. Ability to minimize data inconsistencies and replication of errors downstream of various business activities by ensuring business process and data requirements are aligned and managed over time to facilitate positive data quality impacts on all analytics;
5. The planning, managing, and engagement framework for long-term sustainment;

The project results are available in Exhibit I-23-Staff-87.

Building Owners and Managers Association Toronto Interrogatory # 51

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A AG 15

Interrogatory:

Are the new spaces policy available for use? What reductions, if any, have been made in reducing number of spare transformers and standardizing transformers? Please explain fully.

Response:

Hydro One has begun to standardize in-service three phase step-down transformers for distribution stations. Please refer to interrogatory response Exhibit I-25-Staff-156 part (c) for the specifications. For information on the progress Hydro One has made in reducing the number of spare transformers, please refer to interrogatory response Exhibit I-29-Staff-172 part (a).

Building Owners and Managers Association Toronto Interrogatory # 52

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix B Page: 12

Interrogatory:

a) Please update Requirements to Complete Table on p12.

b) Please explain why there are no management commitments for AG items 2, 3, 4, 6, 8, 9, 12, 14, 15, and 16 to indicate most recent status of each of the tasks?

Response:

a) Please refer to Attachment 6 of Exhibit I-3-SEC-8.

b) All management commitments referenced in this report relate to management's responses that were included in the Auditor General's 2015 Annual Report. Management identified specific Tasks that relate to each of the commitments. The Management commitment statements included in Appendix B, p.12 relate to the Task numbers referenced in Appendix A of the report. Where applicable, specific Tasks were referenced to provide a clear explanation to management in cases where their actions to address the commitments were found to be either partially or substantially complete.

Building Owners and Managers Association Toronto Interrogatory # 53

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix C

Interrogatory:

What is meant by the words "Control Design" as used in the Table?

Response:

A “Control” is an action taken to manage risk and increase the likelihood that established desired outcomes will be achieved. The term “Control Design” refers to the manner in which the control has been established to manage risk and increase the likelihood that established desired outcomes will be achieved.

Building Owners and Managers Association Toronto Interrogatory # 148

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-04 Page: 2

Interrogatory:

Please provide a copy of the feeder prioritization model (AG #9). Please provide the multiyear targets for reliability, as well as the 2022 target. They were to be completed by May 2017.

Response:

The Worst Performing Feeder prioritization model utilizes historic reliability, specifically the average 2014 to 2016 contribution to system SAIDI for each feeder, to develop and prioritize the Worst Performing Feeder investments.

Please refer to interrogatory response Exhibit I-18-SEC-29 for the proposed distribution reliability targets over the term of the plan.

Building Owners and Managers Association Toronto Interrogatory # 149

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-04 Page: 8

Interrogatory:

What steps have been taken to address the data quality (distribution) issues raised by AG #11, Task 42. Please provide a copy of the Design of the Data Governance Project.

Response:

Please refer to interrogatory responses Exhibit I-1-BOMA-45 and Exhibit I-23-BOMA-55 for information on data governance and data quality issues raised in AG #11.

Building Owners and Managers Association Toronto Interrogatory # 150

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-04 Page: 9

Interrogatory:

Please provide the charter for the AMCA project, and a status report on progress of implementation (AG #14).

Response:

Hydro One has no such project.

Building Owners and Managers Association Toronto Interrogatory # 151

Issue:
Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:
A-03-01-04 Page: 10

Interrogatory:
Please provide the output of management's view of spares policy (AG #15) and progress has been made on standardizing transformers and reducing number of spares. Please provide the new spares policy.

Response:
For progress that has been made on standardizing transformers, please refer to interrogatory response Exhibit I-25-Staff-156 part (c).

For progress that has been made on reducing the number of spares, please refer to interrogatory response Exhibit I-29-Staff-172 part (a).

The new distribution spare transformer strategy document is provided as Attachment 1 to this response.

Asset Management Strategy Document

Distribution Station
Operating Spare Transformer Strategy

REVISION HISTORY

Date	**Rev #**	**Purpose of revision**
June 30, 2017	0	New document

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1.0 OBJECTIVE OF STRATEGY DOCUMENT

The objective of this document is to provide strategic direction and establish a framework to manage Hydro One's distribution station operating spare transformer inventory through the following principles:

- Determine optimal number of operating spares using a proven analytical methodology
- Strong and transparent management oversight over operating spare inventory control
- Continuous improvement to minimize carrying costs of operating spares

2.0 EXECUTIVE SUMMARY

Hydro One manages a fleet of approximately 1,220 distribution station (DS) transformers. Operating spares are a strategic investment to mitigate the adverse outcomes resulting from the failure of in-service transformers. These operating spare transformers are required to replace power transformers that have failed, or are failing and must be replaced immediately to maintain the integrity of the system. They are also required to replace transformers which generate customer complaints with noise levels that exceed the guidelines set by the Ministry of Environment and Climate Change (MOECC). Furthermore, operating spare transformers are required to replace in service transformers that have become significantly overloaded due to unexpected customer loading variations.

On average, there have been nine spare transformer deployments per year to support failed transformers, as well as transformers that have high likelihood of failure based on oil samples, demonstrating major oil leaks or violating noise guidelines set by the MOECC. In order to ensure timely response in the event of a failure and maintain system reliability, a sufficient number of spare transformers are required as the lead time to procure transformers can range from 6 to 12 months. If the spare transformer inventory is not maintained, MUSs will be deployed to support failures for prolonged periods of time. As a result of prolonged MUS deployment, planned project and maintenance work would be deferred, resulting in an increase in failures and customer interruptions.

Hydro One uses a proven industry methodology to forecast operating spare requirements for standardized transformers. As of June 2017, the forecast operating spare transformer requirement is 99 standard and non-standard transformers. Hydro One currently has an operating spare pool of 98 distribution system transformers which constitutes 8% of the in-service fleet. In addition, there are 48 engineering reserve transformers which are identified as available for project usage, and will be deployed to planned projects (such as station refurbishments and system development projects) and unplanned projects over the next 10 years.

Since 2016, Hydro One has implemented an inventory management control process. This process uses a centralized system of records to manage inventory levels and minimize carrying costs. Staff from Distribution Asset Management (DAM), Maintenance Technical Services (MTS) and Central Maintenance Shop (CMS) meets regularly to ensure governance and oversight of the inventory management control process.

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3.0 INTRODUCTION

Hydro One manages a large fleet of distribution system (up to 115 kV) transformers which are essential to the distribution of electricity across the province of Ontario. As a distributor, Hydro One is responsible to operate and maintain its distribution facilities in compliance with the Distribution System Code. This includes maintaining distribution facilities in accordance with good utility practices to ensure safe and reliable operation.

As part of a good utility practice, Hydro One manages an inventory of operating spare transformers that can be deployed in the event of in-service transformer failures. Hydro One also manages an inventory of engineering reserve transformers; some of which are reserved for projects, and others which are available for project usage.

The scope of this strategy is limited to distribution system operating spare transformers, and engineering reserve (ER) transformers identified as being available for project usage. This document establishes strategic direction for management of these transformers to support corporate objectives, explains the analytical methodology used in forecasting spares, risk factors, the current inventory management process and identifies the implementation plan.

The DS spare transformer strategy ensures that optimum quantities and types of replacement transformers are ready for deployment to any DS experiencing an unplanned failure or other emergent need. Emergent needs include replacement of units with internal heating issues, unsatisfactory oil test results, significant oil leaks, tap changer functionality issues, noise levels non-compliant with MOECC guidelines, among other issues that have required a unit to be forced out-of-service or replaced in a short time period. This strategy includes the proper maintenance programming to ensure units are operationally ready for service and deployable to site.

4.0 ABBREVIATION AND DEFINITIONS

4.1 Abbreviations

CMS	Center Maintenance Shop in Pickering
DAM	Distribution Asset Management
DETC	De-Energized Tap Changer
DS	Distribution Station
ER	Engineering Reserve
HONI	Hydro One Networks Inc.
iMDS	Integrated Modular Distribution Station
MOECC	Ministry of Environment and Climate Change

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MTS	Maintenance Technical Services
MUS	Mobile Unit Substation
OSL	Operating Spare Level (of readiness)
OS-L1	Operating Spare – Level 1
OS-L2	Operating Spare – Level 2
OS-L3	Operating Spare – Level 3
ULTC	Under Load Tap Changer

4.2 Definitions

Available for Project Usage	DS transformers in inventory which are not reserved for any planned or unplanned capital projects, and are not required to be retained as operating spares when there is sufficient operating spare coverage. If there is a shortfall of operating spares to satisfy spare requirements, then these transformers can be reclassified as operating spares. These transformers are a subset of engineering reserves. They can be reserved for station refurbishment projects, system development projects and failure replacement projects. They can be new or used. They receive inspections and maintenance but may not necessarily be of OS-L1 level of readiness.
Distribution System Transformers	DS voltage class power transformers such as step-down transformers and regulators. Distribution system transformers convert a high level voltage (typically 115 kV, 44 kV or 27.6 kV) to a lower distribution voltage (typically 27.6 kV, 25 kV, 13.8 kV, 12.47 kV, 8.32 kV and 4.16 kV).
De-Energized Tap Changer	Transformers tap changer which requires that the transformer be de-energized in order for it to be operated.
Spare Transformer Owner	Accountable distribution asset manager for the operating spare and engineering reserve transformer inventory.
Engineering Reserve	Engineering reserve power equipment is a combination of those purchased or reserved for capital projects, and those which are available for project usage. They include power equipment either newly procured or retained from decommissioned facilities. These units can also be made available for external sale; used as seed equipment for replacement projects, system development projects or reclassified as operating spares as needed. This equipment can be new or old.

Integrated Modular Distribution Station	A station design, construction and commissioning solution that was conceptualized to deliver cost savings, allow for installation where real estate is limited, and improve aesthetics in urban areas.
Mobile Unit Substation	Mobile unit substations (MUSs) are mobile DS's mounted on trailers which are utilized for DS load relief, contingency in the event of failure, and support planned and unplanned maintenance and capital work.
Non-Standard Transformer	Distribution system transformers for which its ratings do not satisfy those found in SS-54410-001 - R1, Table A and Table B under the "Standard Ratings" sections. These include but are not limited to transformers identified as "Non-Standard" in SS-54410-001 - R1 Table A and Table B. Other examples of non-standard transformers include regulators, single-phase transformers, iMDS transformers, padmount transformers and stepdown transformers with side-mounted enclosed bushings.
Operating Spares	Power equipment such as transformers which are reserved and maintained for emergency replacements to maintain system reliability and normal system configuration. Minimum quantities of this class are reserved for this purpose, and are not considered as seed equipment for refurbishment, replacement or development projects. These spares can be new or old.
Operating Spare – Level One	An operating spare identified that is complete in all aspects and will meet all expected system duty requirements. Asset condition evaluation indicates only Acceptable conditions; no ancillary or major parts are missing and will be ready to leave the yard within 7 days.
Operating Spare – Level Two	An operating spare identified that is complete in most aspects and will meet all expected system duty requirements. Asset condition evaluation indicates only deficiencies that can be addressed such that the unit will be ready for dispatch to site within 8 to 30 days.
Operating Spare – Level Three	A unit identified that is not complete, may not meet all expected system duty requirements or may not be ready for service within 30 days. Some minor and major parts or components may be missing but can be replaced. The unit will only be repaired or upgraded if it is technically and financially justified and or; in specific circumstances; a lack of OSL1 or OSL2 unit of the same spare group becomes a need based on urgencies.
Padmount Transformers	Padmount transformers are those for which the primary and secondary bushings are enclosed and the primary and secondary supply to and from the transformer

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	is through underground cables.
Standard Transformer	Distribution system transformer for which its ratings satisfy those found in SS-54410-001 - R1, Table A – Transformers with ULTC and Table B – Transformers with DETC under the "Standard Ratings" sections.
Strategic Parts and Components Inventory	Essential parts or components of a unit required to ensure reliable operation of power equipment. They are specialty components with long lead times or components that are no longer supported by the original equipment manufacturer. Strategic parts or components are sometimes referred to as safety-stock and are typically kept at minimum levels. Examples of strategic parts and components are tap changers, bushings and cooling fans.
Under Load Tap Changer	Under load tap changers are transformer tap changers which have the ability to maintain the load while changing taps. The transformer remains in service while tap changes are made automatically based on system voltage fluctuations.

5.0 SCOPE OF THE STRATEGY DOCUMENT

This document is intended to establish a strategy for Hydro One's distribution station operating spare transformers, and engineering reserve transformers that are identified as being available for project usage. Engineering reserve transformers that have been reserved for projects, as well as strategic parts and components inventory are not in the scope of this document.

6.0 CORPORATE STRATEGIC OBJECTIVES

The DS spare transformer strategy was developed in accordance with Hydro One's distribution business objectives. Table 1 below outlines the goals and how this strategy will contribute to achieving corporate objectives.

Strategic Objective		Goal	Action
Customer Focus	Customer Satisfaction	Improve current levels of customer satisfaction.	Adequate spare units will ensure replacement of equipment in a timely manner with minimal impact to customers.
		Engage with our customers consistently and proactively. Ensure our investment plan reflects our customers and desired outcomes.	

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Operational Effectiveness	Cost Control	Actively control and lower costs through OM&A and capital efficiencies.	Standardization in transformer design allows for reduction in spare pool size and minimization of carrying costs
	System Reliability	Maintain reliable operation of the distribution system.	Maintaining an adequate level of operating spare units, installing them in a timely manner and minimizing the utilization of MUSs for extended periods of time will ensure timely restoration of the distribution system to normal configuration and reliability.
Public Policy Responsiveness	Public Policy Responsiveness	Ensure compliance with the Distribution Rate Handbook and Distribution System Code	Maintaining the existing service reliability performance of the system and ensuring that appropriate follow up and corrective action is taken regarding problems identified during inspections of stations and spare inventory.
	Environment	Sustainably manage our environmental footprint	Mitigate potential oil release from failing in-service transformers by removing them from service and replacing them with operating spares prior to failure.
Financial Performance	Financial Performance	Realize cost saving opportunities	Realize cost savings through planned replacements of transformers identified as failing prior to failure as the cost of emergency replacements is more expensive. Also realize cost savings through standardization and elimination of spare transformer categories.

Table 1: Corporate Strategic Objectives

7.0 DISTRIBUTION ASSET DESCRIPTION DETAILS

In 2010, Hydro One performed an assessment of spare transformer requirements for DSs using 2001 to 2008 transformer failure information. Details and results of the spare transformer assessment are contained in Appendix 1. Within the Appendix 1 document, Table 5 summarizes the number of required standard rating spare transformers based on a Markov Model methodology. Standard groups with designation "TA" indicate units equipped with under load tap changers (ULTC). Standard groups with designation "TB" indicate those that do not contain an ULTC, thus have de-energized tap changers (DETC).

The Markov Model performed in 2010 analyzed fifteen standard 3-phase transformer categories; however, there were additional 3-phase non-standard transformer categories which were not analyzed. Furthermore, the study did not analyze 1-phase spare transformers, voltage regulators, padmount style transformers and iMDS transformers. An additional Markov Model analysis will be completed by end of 2018 across all transformer categories.

In 2015, Distribution Asset Management (DAM) re-assessed the in-service population of all 3-phase transformers with consideration to primary side and secondary side voltage, MVA and tap changer capability. A DS Spare Transformer Inventory Excel sheet was produced with two tabs. The first tab “DS Transformer Categories” contains the number of in-service and spare transformers by category to ensure spare transformer availability. The second tab “DS Transformer Inventory at CMS” contains the list of operating spare and engineering reserve transformers. The list of spare transformers in the Excel sheet and in SAP is updated on an ongoing basis when transformers are reserved for projects. Also, when spares are reserved, the number of available spare transformers in the affected category is reviewed to determine if a spare must be purchased. The DS spare transformer strategy will be reviewed and updated annually (by year-end) from 2017 onward. The excel sheet contains the following information:

DS Transformer Categories:

- Transformer / Regulator categories with consideration to MVA, HV/LV voltage, ULTC/DETC capability
- In-service population of transformers for each category
- 2010 Markov Model suggested number of operating spares for standard transformer categories
- Detailed operating spare strategy for standard and non-standard transformer categories
- Required number of operating spares in each category as per strategy
- Number of operating spare and engineering reserve transformers available for project usage that are in inventory at CMS in each category
- Number of operating spares on order and to be ordered to address any operating spare transformer shortfalls

DS Transformer Inventory at CMS:

- List of engineering reserve transformers reserved for projects
- List of engineering reserve transformers available for project usage
- List of operating spare transformers

On a regular basis, the DAM spare transformer owner extracts a list of operating spare and engineering reserve transformers from SAP, places these transformers into the DS Spare Transformer Inventory Excel sheet, and categorizes the transformers based on characteristics.

As DS operating spare and engineering reserve transformers available for project usage are deployed to support failing/failed transformers or those which generate noise complaints, the purchasing strategy is to replenish the spare pool with an adequate number of operating spares, using the "DS Spare Transformer Inventory" Excel sheet as a guide. Because the Markov Model was not performed for all variations of MVA capacity levels (ex. performed for 7.5 MVA, but not 5 & 10 MVA), in certain instances it is prudent to carry more or less than the Markov Model calculated level. More recent failure data also contributes to variation from the recommended number of spares suggested by the 2010 Markov Model results.

From the 2015 assessment, it was identified that some spare transformer categories are overstocked. In 2017, these surplus spare transformers have been reclassified as engineering reserve transformers that are available for project usage. For such categories, the strategy is to deploy these surplus transformers to planned capital projects including DS rebuilds and system reinforcement projects. These surplus engineering reserve transformers which are available for project usage can also be reclassified as operating spares to be deployed to support a failure in an effort to reduce the transformer inventory at CMS.

Moving forward, a new operating spare transformer will be purchased for a category only if the following two conditions are satisfied:

1. There are no engineering reserve transformers identified as being available for project usage.
2. The number of available operating spare transformers is less than the optimized spare level for the category, identified in the DS Spare Transformer Inventory Excel sheet, DS Transformer Categories tab, Column P "Required # of spares as per Strategy".

8.0 OPERATIONAL ASSET MODEL

When DAM planners are developing scopes of work for planned projects involving station transformer replacements or installations, they must first refer to the list of engineering reserve transformers available for project use in the DS Spare Transformer Inventory Excel sheet, "DS Transformer Inventory at CMS" tab, to determine if a suitable available transformer can be assigned to their project. If the DAM planner finds a suitable engineering reserve transformer available for usage, he/she must inform the DAM spare transformer owner so that the transformer can be reserved in the Excel sheet and in SAP. In the "Status" column of the Excel sheet, these transformers are identified as "ER, Available for Project Use". If the planner is unable to locate a suitable engineering reserve transformer available for project usage, then the planner must purchase a new standard rating transformer under his/her project.

Standard DS transformer ratings can be found in SS-54410-001 - R1 - Transformers: Power, Sealed Tank Type Voltage Classification of 123kV and Less, Table A – Transformers with ULTC and Table B – Transformers with DETC (Note, no similar document contains standards for padmount transformers, single-phase transformers, regulators, and transformers for iMDS). No planners are to purchase transformers for projects outside of current standard ratings unless appropriate approvals from DAM Management are provided.

Transformers identified as operating spares shall not be considered for planned project usage, and are to be retained for unplanned emergent replacements.

Transformers identified as engineering reserves are either purchased or reserved for capital projects, or are available for project usage. When a transformer is required for an emergency replacement project, engineering reserve transformers that are not reserved and available for usage can be reserved.

All transformer reservations for planned and unplanned project purposes must be discussed with the DAM spare transformer owner of the DS Spare Transformer Inventory, to allow reservations to be tracked in the Excel sheet, allow MTS and CMS to be notified and to allow SAP to be updated with the reservation. DAM spare transformer owner updates the spare transformer inventory in the Excel sheet, and CMS Inventory Specialist updates the SAP inventory.

9.0 MANAGING RISKS

Condition risks for operating spares are defined as readiness for spare deployment. Condition risks are mitigated through routine maintenance that is performed on operating spares and tracked in SAP for completion. Spares are maintained in the same manner as in-service equipment.

Demographic and utilitization risks for operating spare pertain to the risk of operating spares not being deployed and aging beyond the warranty term. Going forward, Hydro One will utilize a first-in-first-out protocol to ensure operating spare transformers are deployed in a timely manner.

Economic risks are defined as costs that may be incurred if an operating spare unit is not made available and installed in a timely manner. The following are examples of costs associated with economic risk:

- Cost premiums due to accelerated purchase and delivery requirements of transformers under emergency scenarios.
- Additional costs due to extra remediation actions nescessary to restore supply to customer and restore reliability of the system.

10.0 TECHNOLOGY INNOVATION OPPORTUNITIES

Hydro One employs a fleet of 29 Mobile Unit Substations (MUSs) which were purchased to support the following purposes:

- Emergency power restoration in the event of a distribution transformer or DS failure
- Offload DSs during capital projects and maintenance activities

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- Provide DS transformer load relief in emergency situations when transformers are loaded beyond their planned-loading limits.

Most DSs are operated with one transformer, and rely on the availability of a MUS for contingency. MUSs are stations on trailers that can be dispatched to a DS to restore supply. Of the 29 MUSs, approximately 12 are placed on standby and reserved for emergency deployment. Over 73% of Hydro One DSs (over 730) were built with a single transformer bank and are equipped with MUS connection facilities; relying on the MUS fleet for contingency. This fleet of 29 MUSs allows for the absence of a second transformer bank at these 730 stations, allowing for a cost efficient solution for contingency planning.

Hydro One is in the process of acquiring new additional MUSs to help overcome the challenges associated with contingency planning, system restoration requirements for planned and unplanned transformer replacements, and an increase in the amount of planned DS capital work to keep pace with the deteriorating condition and demographics of DS assets.

11.0 ASSET STRATEGY – OPERATION AND MAINENANCE

11.1 Inventory Management

Hydro One uses SAP as its centralized system of record for inventory management across all lines of business. Asset hierarchy for all operating spare and engineering reserve transformers are contained in SAP. Once per month, the DAM spare transformer owner extracts a list of operating spare and engineering reserve transformers from SAP, and places them into the DS Spare Transformer Inventory Excel sheet. From here, the transformers are categorized based on characteristics such as MVA, primary and secondary voltages, tap changer functionality and conventional versus padmount design.

DS operating spare transformers are designated for emergency deployment when an in-service distribution system transformer has failed, or is failing and must be replaced immediately to maintain the integrity of the system. They are also required to replace transformers which generate customer complaints with noise levels that exceed the guidelines set by the Ministry of Environment and Climate Change (MOECC). Furthermore, operating spare transformers are required to replace in service transformers that have become significantly overloaded due to unexpected customer loading variations.

Based upon review of the transformer inventory, it has been identified that some operating spare transformer categories have been overstocked. In 2017, these surplus spare transformers have been reclassified as engineering reserve transformers that are available for project usage. For such categories, the strategy is to deploy these surplus transformers to planned capital projects including DS rebuilds and system reinforcement projects.

The deployment of the operating spare transformers shall follow a first-in-first-out protocol to optimize use of the service life of the spares. Operating spares shall be maintained in accordance with established practices to ensure they are ready for deployment when required.

Staff from DAM, MTS and CMS meet periodically to jointly review operating spares inventory requirements. The joint review consists of the following:

- Assess inventory levels and spare requirements
- Review units deployed
- Ensure routine maintenance is completed
- Assess and recommend spares that should be surplused

Summary of Short Term Strategic Goals (5 years Outlook)

Currently there are 98 DS operating spare transformers across 46 categories, and 48 DS engineering reserve (ER) transformers that have been identified as available for project usage. By the end of the five year business cycle, the plan is to reduce the number of ER transformers available for project usage from 48 down to 31. This will be achieved by the following:

- Deployment to planned and unplanned capital projects
- Surplus of transformers in inventory where appropriate
- Reclassification of ER transformers available for project usage as operating spares, when there is a shortfall of operating spares
- Identification of surplus transformers in inventory for resale

This long term view excludes spare transformers which may potentially be purchased or acquired to support acquisitions, and newer designs such as iMDS and padmount transformers.

It should be noted that since early 2016 during the process transition year, the inventory of 161 operating spare and ER transformers available for project usage across 60 categories has been reduced to 146 transformers across 46 categories.

Summary of Long Term Strategic Goals (>5 years)

Long term strategic goals beyond the next 5 years include the following:

- Reducing the number of DS engineering reserve transformers available for project usage down to 0 within the next 10 years.
- Reduction of the number of operating spare categories by reducing the number of non-standard voltage combinations and number of MVA capacities.

Further reduction of operating spare categories could be achieved on a long term basis through elimination of lower system voltages, although such voltage conversion projects are costly to implement.

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11.2 DS Transformer Inventory Maintenance Strategy

DS Operating Spare Preventive and Corrective Maintenance investments are in place to maintain the spare transformers' level of readiness for deployment, to ensure they are available when required to support failures or demand replacements.

Visual inspections and preventive maintenance of the operating spare transformers are performed in accordance with Work Standard Document SM-54-059 - Distribution Class Operating Spare Transformers and Regulators - All Voltages - All Capacities. This work is executed through SAP maintenance plans and work orders created by DAM. Reporting is performed through SAP notifications.

During maintenance, the following tasks are performed:

- *Visual Inspection*: Visual check of the condition of all parts and identification/reporting of parts that are missing. Identification of any oil leaks that are observed.
- *Maintenance Level 1*: Function tests of tap changers and filtration systems, and application of touch up paint on damaged or corroded areas.
- *General Oil Test (GOT)*: Oil samples from the transformer main tanks are obtained and analyzed.
- *Tap Changer Oil Analysis (UTOA)*: Oil samples from the transformer ULTC compartment (where applicable) are obtained and analyzed.

The maintenance strategy is to perform preventive maintenance on all DS operating spares and engineering reserve transformers available for project usage every two years. Following preventive maintenance work and inspections, deficiencies identified are addressed under the DS Operating Spare Corrective Maintenance Program. CMS is required to maintain at least one operating spare transformer in each of the 46 operating spare categories to OS-L1 level of readiness. Furthermore, CMS is expected to maintain as many operating spares to OS-L1 level of readiness as possible as per OM&A budgetary constraints.

The following Capital and OM&A investments support DS spare transformers:

- AIP000165 – AR 19299 DS Transformer Purchase Program. Provides for the purchase of DS spare transformers.
- AIP000155 – AR 19337 DS Demand / Emergency Capital Program. Funds the emergency installation of spare transformers.
- AIP000260 – AR 22157 DS Operating Spare Mtce. & Inspection. Provides for the inspection and diagnostic testing of spare transformers.
- AIP000259 – AR 21256 DS Operating Spare Corrective Maintenance. Upon identification of defects through inspection and diagnostic testing, provides for corrective maintenance activities.
- AIP000258 – AR 19310 DS Transformer Overhaul Program. Provides for mid-life overhaul of in-service transformers, as well as major corrective work on DS operating spare transformers, and ER transformers available for project usage.

12.0 IMPLEMENTATION PLAN

The following are the major components in implenting the DS Operating Spares Transformer Strategy.

1. The DAM spares owner, MTS and CMS will continue to monitor and provide oversight of the DS transformer inventory.
2. Engage relevant lines of business to ensure clear accoutabilities are understood as it pertains to the planning, procuring, maintaining, deploying and surplusing of operating spares and ER transformers that are available for usage.
3. Ensure funding is available for maintenance and capital investment of transformers in inventory, and ensure that transformers in inventory are receiving required maintenance.
4. Provide and maintain clear separation of Tx versus Dx spare transformer inventory, and keep SAP up-to-date with the categorization required for the separation.
5. The DAM spares owner to continue to engage and encourage DAM planners to utilize ER transformers available for project usage for their planned projects in an effort to reduce the overstocked inventory and lower the cost of their planned capital projects.

13.0 REFERENCES

[1] Hydro One Networks Inc., “Special Study Reports – Assessment of Spare Transformer Requirements for Distribution Stations”, 2010.

Appendix 1 DS Transformer Markov Model

The following MS Word document contains a report on the “Assessment of Spare Transformer Requirements for Distribution Stations”. This report was prepared by Special Studies in 2010 and contains a Markov Model analysis and results.

ds_spare_assess_study.docx

Ontario Sustainable Energy Association Interrogatory # 1

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

Previous Proceeding – EB-2011-0118

Interrogatory:

a) Please provide an update to the OEB direction in the following proceeding: Hydro One Networks Inc: Application by Hydro One Networks Inc. for a six-month exemption from the obligations in Section 6.2.6 and 6.2.7 of the Distribution System Code. Please submit a table indicating the annual connection performance compared to the standards in the Distribution System Code from 2009 until the present.

Response:

Annual connection performance, compared to the standards in the Distribution System Code, from 2009 until 2017, are provided below:

Year	**Connection Standards**	**% connected within 5 business days**
2009	100% connected within 5 business days	**35.00%**
2010	100% connection within 5 business days	**97.49%**
2011	Jan to Oct 11 - 100% connected within 5 business days Oct 12 and Onward - 90% connected within 5 business days (under exemption)	**82.61%**
2012	90% connected within 5 business days (under exemption)	**95.95%**
2013	90% connected within 5 business days (DSC amended on Jun 13)	**99.69%**
2014	90% connected within 5 business days	**100.00%**
2015	90% connected within 5 business days	**99.78%**
2016	90% connected within 5 business days	**99.79%**
2017	90% connected within 5 business days	**99.69%**

Witness: LISTER Warren

The Society of Energy Professionals Interrogatory # 1

Issue:
Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:
None

Interrogatory:
Please file Hydro One's relevant updated financial reports as they become publicly available including quarterly and annual MD&A and consolidated financial statements, Networks Distribution annual financial statements, credit rating reports etc.

Response:
Please refer to Exhibit I-32-BOMA-B153 Attachments 1 to 9 for Hydro One Limited and Hydro One Inc. MD&A and consolidated financial statements for Q1, Q2 and Q3 of 2017.

Hydro One will submit the audited 2017 MD&A and consolidated financial statements once available.

Please refer to Exhibit I-36-BOMA-B156 Attachments 1 to 7 for rating agency reports by DBRS, Moody's and S&P, released since those included in the prefiled evidence.

Hydro One Distribution will submit the audited 2017 financial statements once available.

Association of Major Power Consumers in Ontario Interrogatory # 2

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

A-04-01
Customer Service Strategy

Interrogatory:

a) Page 2: Hydro One indicates it has made several digital investments which address customer feedback received. Please provide the feedback and identify the specific digital investments.

b) Page 5: Hydro One states, "Through surveys and the Customer Engagement work held in 2016, Hydro One confirmed that it needed a renewed focus on this customer segment." Please explain further the reasons why a renewed focus on Commercial and Industrial customers is required.

c) Page 5: Hydro One states each of its eight zones has a Zone Superintendent for Large Industrial Accounts. Does Hydro One have specific reliability data for each of the eight zones?

d) Page 5: Please confirm the dates in 2016 and in 2017 for the annual Large Customer Conference and provide the agenda, and presentation materials and meeting notes for the 2016 and 2017 Conference.

e) Page 5: Please summarize the key needs and preferences of Large Distribution Accounts (LDA) identified during meetings between Zone Superintendents and LDA, and confirm the resulting expenditures proposed in this application that are specifically directed at LDA.

f) Page 7: With respect to the Ombudsman Office, please provide the number of systemic investigations since inception and summarize any underlying trends of concern relevant to this application and the changes needed.

Response:

a) Hydro One's Distribution Rate Application includes several digital investments to address customer feedback, as outlined below. Additional information can be found in the Investment Summary Documents referenced below:
   - Web & Mobile App (GP-16)
   - Customer Data and Analytics (GP-32)
   - Bill Redesign (GP-29)
   - Call Centre Technology (GP-28)

b) Commercial and Industrial customers are deploying new technology and processes which are increasingly impacted by power quality or reliability issues. In addition, customers are increasingly pursing load displacement and storage projects. As result of these trends, this customer segment relies on Hydro One to help resolve issues and pursue opportunities.

c) Hydro One does not maintain zone specific reliability data.

d) The 2016 Large Customer Conference was held on November 21 and 22. The next Large Customer Conference is scheduled for February 2018. For the requested materials, please refer to attachments 1 and 2 of Exhibit I-2-AMPCO-002.

e) Hydro One does not have a summary of the needs and preferences of Large Distribution Accounts (LDA) identified during meetings between Zone Superintendents and LDAs. These meetings occur informally and regularly throughout the year and are meant to address complex individual customer needs on a case by case basis. The meetings are not intended for the purpose of obtaining a summary of the needs and preferences of LDAs. Hydro One identified and summarized LDA customer needs and preferences through a comprehensive customer engagement process. The engagement process was conducted by Ipsos and obtained LDA needs and preferences through an on-line survey and in-person workshops. Exhibit B1, Tab 1, Schedule 1, DSP Section 1.3.2 (5.2.2 A) Customer Engagement Process explains this customer engagement process. A summary of the LDA customer needs and preferences identified through the customer engagement process forms part of the Large Customer Conclusion section of the report, see Exhibit B1, Tab 1, Schedule 1, DSP section 1.3 Attachment 1: on page 146 and 147. For details on the expenditures Hydro One is proposing to address LDA specific needs and preferences see Exhibit B1, Tab 1, Schedule 1, DSP section 1.3.4 (5.4.1 F) How the Plan Reflects Customer Needs and Preferences, page 19, lines 16-27 and page 20, lines 1-15.

f) The office opened on March 14, 2016. In 2016, the office commenced one formal systemic investigation as defined in the Terms of Reference and Mandate. The investigation focused on the quality of supervision as well as metrics and controls in Hydro One's complaint service, starting with the call agents managed by a third-party contactor through to the escalated complaints centre operated by Hydro One.

The systemic investigation resulted in 28 recommendations covering the following areas:

- improving governance and controls over call centre operations
- providing staff and management with the tools, training, and coaching needed to successfully meet job responsibilities
- streamlining customer complaint processes
- creating a leadership group to identify solutions to process gaps and inefficiencies.

The company is taking steps to implement the office's recommendations including bringing the call centre in-house and by developing a centralized complaints system. In addition to the formal systemic investigation, in 2016 the office also made recommendations on systemic issues that arose during the course of individual investigations – please refer to Exhibit I-38-CCC-037.

In 2017, the office did not commence any formal systemic investigations as defined in the Terms of Reference and Mandate. Nevertheless, while completing individual investigations, the office identified a number of systemic issues and addressed them through recommendations – please refer to Exhibit I-38-CCC-037.

AGENDA

2016 LARGE CUSTOMER CONFERENCE AGENDA

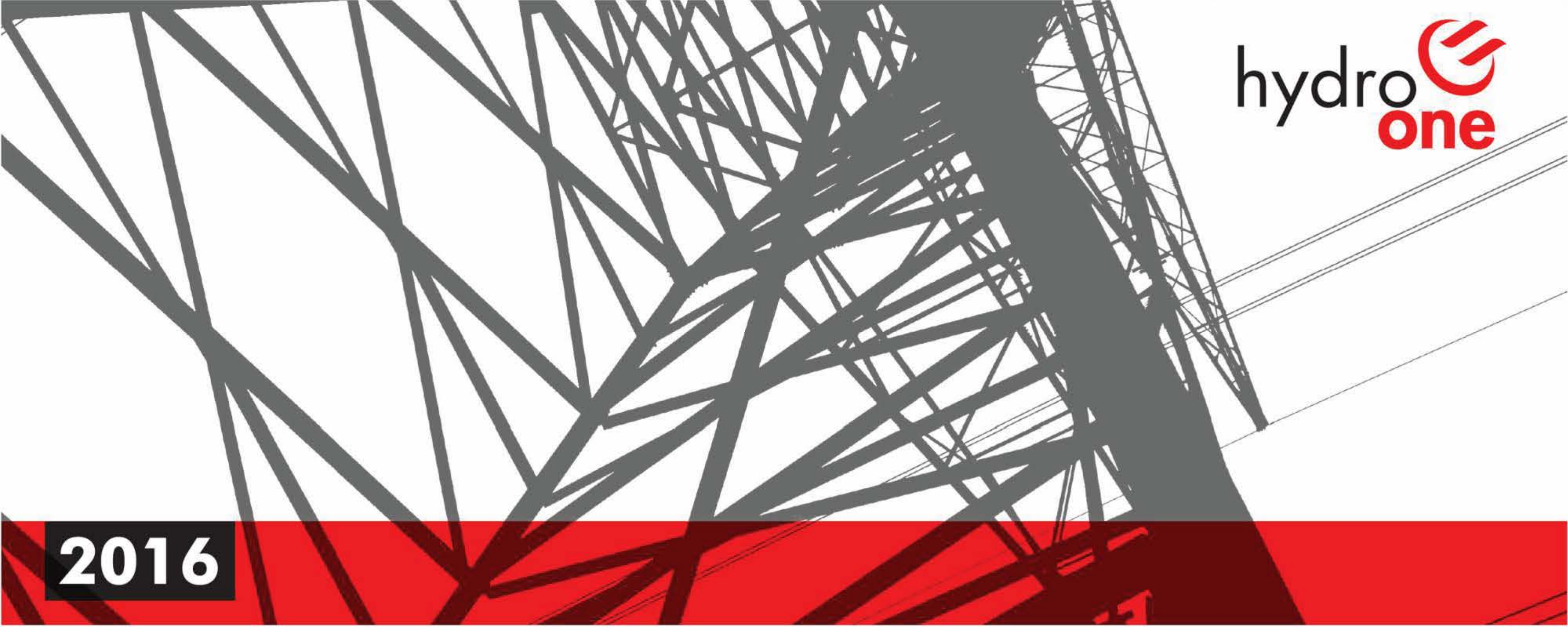
NOVEMBER 21 – DAY 1 (LARGE CUSTOMER SESSION – AMBROISA GRAND BALLROOM)		
Start Time	**Topic**	**Details**
7:00 a.m.	Registration, Coffee and Hot Breakfast	
9:00 a.m.	Opening Conference Remarks by Mike Penstone, Vice President, Planning, Hydro One and Greg Kiraly, Chief Operating Officer, Hydro One	
9:30 a.m.	Hydro One's Transmission Customer Consultation & Proposed Investment Plan	Presentation by Graham, Director, Key Account Management, Hydro One, and Scott McLachlan, Director, Transmission Asset Management, Hydro One
Break		
10:45 a.m.	Increasing Productivity at Hydro One	Presentation by Andy Stenning, Vice President, Stations and Operations, Hydro One and Jon Rebick, Vice President, Lines and Forestry, Hydro One
Break		
1:15 p.m.	Cyber Security in the Power Industry	Presentation by Rick Haier, Chief Security Officer, Hydro One and Francis Bradley, Vice President, Canadian Electricity Association (CEA)
Break		
2:30 p.m.	Long Term Energy Plan (LTEP)	Presentation by Michael Lyle, Vice President, Planning, Legal, Indigenous Relations and Regulatory Affairs, IESO
Extended Break		
5:00 p.m.	Cocktail Reception	
6:00 p.m.	Executive Dinner in the Ambrosia Grand Ballroom	

**Topics and speakers are subject to change without notice.*

NOVEMBER 22 – DAY 2 (BREAKOUT SESSIONS, AMBROSIA ROOMS 1, 2, 3 & 4)				
Start Time	**End Users**	**LDCs**	**Generators**	**LDAs**
7:30 a.m.	Registration, Coffee and Hot Breakfast			
8:30 a.m.	**Voice of the Customer** Facilitated by Mike Penstone, Vice President, Planning, Hydro One and Scott McLachlan, Director, Planning Optimization, Hydro One	**Voice of the Customer** Facilitated by Andy Stenning, Vice President, Stations and Operating, Hydro One	**Voice of the Customer** Facilitated by Brad Bowness, Vice President, Construction Services, Hydro One, and Andrew Spencer, Director of Engineering, Hydro One	**Voice of the Customer** Facilitated by Jon Rebick, Vice President, Lines and Forestry, Hydro One
Break				
9:45 a.m.	**CDM Program Delivery** Declan Doyle, Manager, Direct Customers	**Transmission Reliability** Scott McLachlan, Director, Planning Optimization, Hydro One	**Journey into the Control Room** Aaron Cole, Network Management Officer, Customer and Operating Support, Hydro One, and Mark Artymko, Grid Operations Manager, Hydro One	**Power Quality Audits** Luis Marti, Director, Reliability Studies, Power Quality RD&D, Hydro One
Break				
10:45 a.m.	**Transmission Reliability** Scott McLachlan, Director, Planning Optimization ,Hydro One	**Journey into the Control Room** Aaron Cole, Network Management Officer, Customer and Operating Support, Hydro One, and Mark Artymko, Grid Operations Manager, Hydro One	**Net Metering, Load Displacement Generators and Energy Storage** Jaspreet Nijjar, Settlement Supervisor, Hydro One	**Power Distribution Operations** Tam Kennedy, Superintendent Provincial Lines, Hydro One
Lunch				
12:45 p.m.	**Journey into the Control Room** Aaron Cole. Network Management Officer, Customer and Operating Support, Hydro One, and Mark Artymko, Grid Operations Manager, Hydro One	**Lidar** Presentation by Chong Kiat Ng, Director, Transmission Asset Management, Hydro One	**Power Quality** Luis Marti, Director, Reliability Studies, Power Quality RD&D, Hydro One	**OGCC Business Strategy & Project Delivery** James McGowan, Business Strategy & Project Delivery, Ontario Grid Control Centre, Hydro One
Break				
1:45 p.m.	**Lidar** Presentation by Chong Kiat Ng, Director, Transmission Asset Management, Hydro One	**CCRA True-ups** Presentation by Wade Frost A review of the IE model and CG guidelines.	**Transmission Reliability** Presentation by Scott McLachlan, Director, Planning Optimization, Hydro One	**IESO Update** Presentation by Rouselle Gratela, Business Manager, LDCs, IESO
Break				
2:45 p.m.	**Net Metering, Load Displacement Generators and Energy Storage** Jaspreet Nijjar, Settlement Supervisor, Hydro One	**Power Quality** Luis Marti, Director, Reliability Studies, Power Quality RD&D, Hydro One	**Outage Planning** Jason Boniface, Manager, Grid Operations	**CDM & Co-Gen** Gillian Lind, Conservation Demand Management, Hydro One
Break				
3:45 p.m.	**Power Quality** Luis Marti, Director, Reliability Studies, Power Quality RD&D, Hydro One	**Net Metering, Load Displacement Generators and Energy Storage** William Cheng, Manager, Transmission & Distribution Settlement, Hydro One	**Lidar** Presentation by Chong Kiat Ng, Director, Transmission Asset Management, Hydro One	**Net Metering, Load Displacement Generators and Energy Storage** Monika Amorim, Senior Settlement Analyst, Transmission & Distribution Settlements, Hydro One
Break				
4:30 p.m.	Close of conference, including prizes draw and closing remarks			

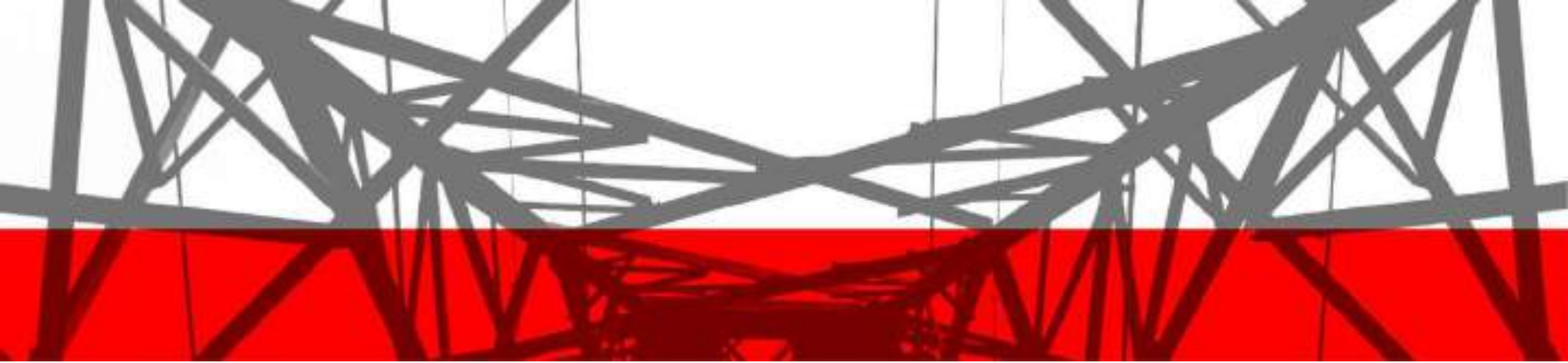
Topics and speakers are subject to change without notice.

Response to IR – I – 02-AMPCO-002



LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency

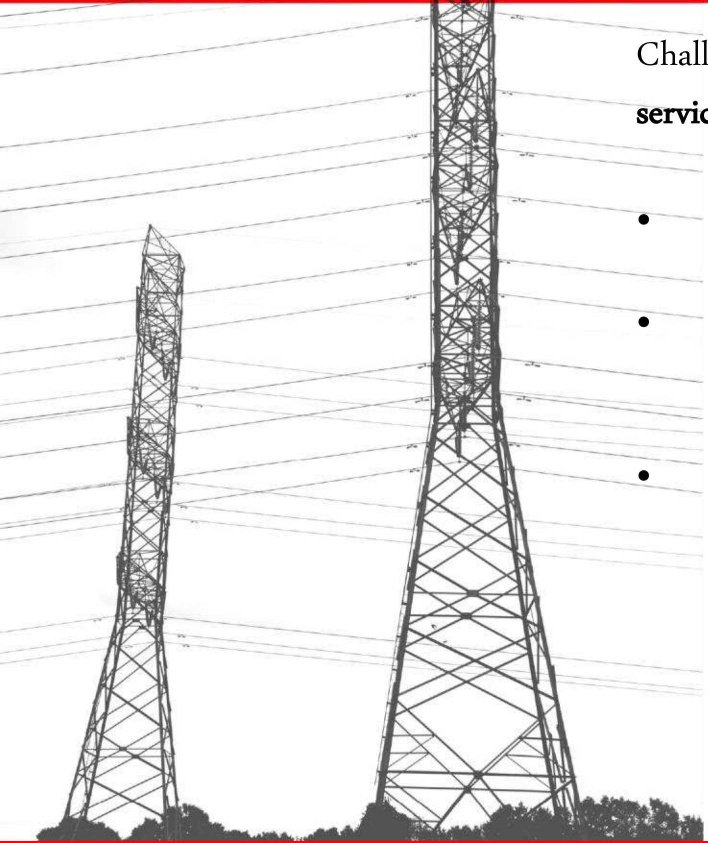


INCREASING PRODUCTIVITY AT HYDRO ONE

Andy Stenning
Vice President, Stations & Operations
Hydro One

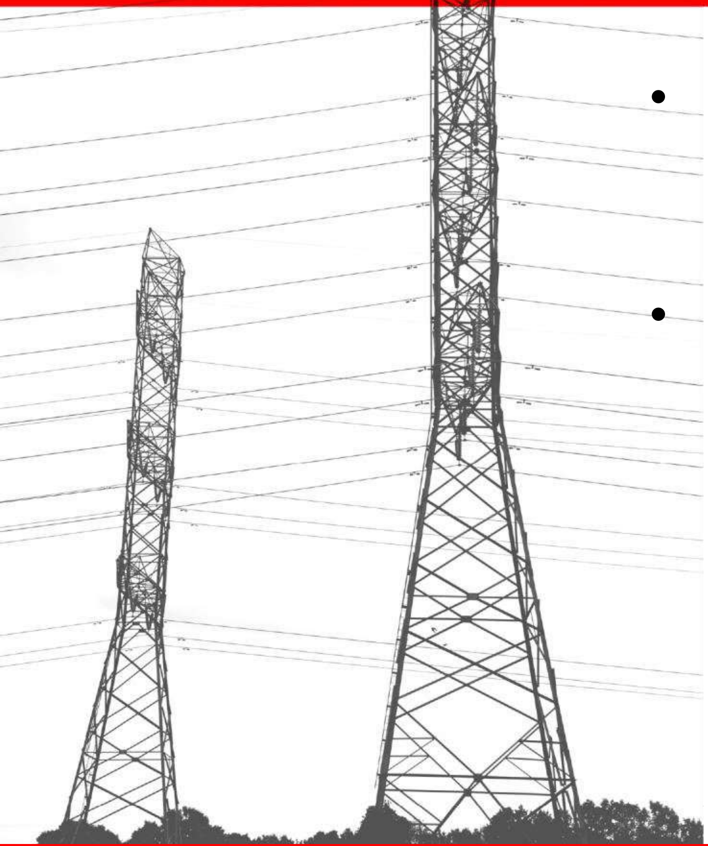
Jon Rebick
Vice President, Lines & Forestry
Hydro One

WHY ARE PRODUCTIVITY IMPROVEMENTS IMPORTANT?



Challenges: Increase **system performance** with **reduced costs** amidst **increasing customer service expectations**

- The recent Auditor General Report challenged Hydro One to improve reliability
- The Ontario Energy Board (OEB) has challenged Hydro One to increase productivity in the field to self-fund future projects
- Our province-wide customer base has challenged us to deliver transparent, reliable, and best-in-class customer service



CUSTOMERS

- Reality is we cannot continue to increase budgets and impact customer rates to perform needed maintenance and upgrades to the system

- Must use available funding in the most efficient manner possible, while benefiting the highest number of customers in terms of reliability
  and affordability

OPERATIONS AND MAINTENANCE

- Operations and Maintenance (O&M) activities are the largest cost of the company which impact our bottom line, customer and OEB

- Looking to improve the performance of our O&M activities

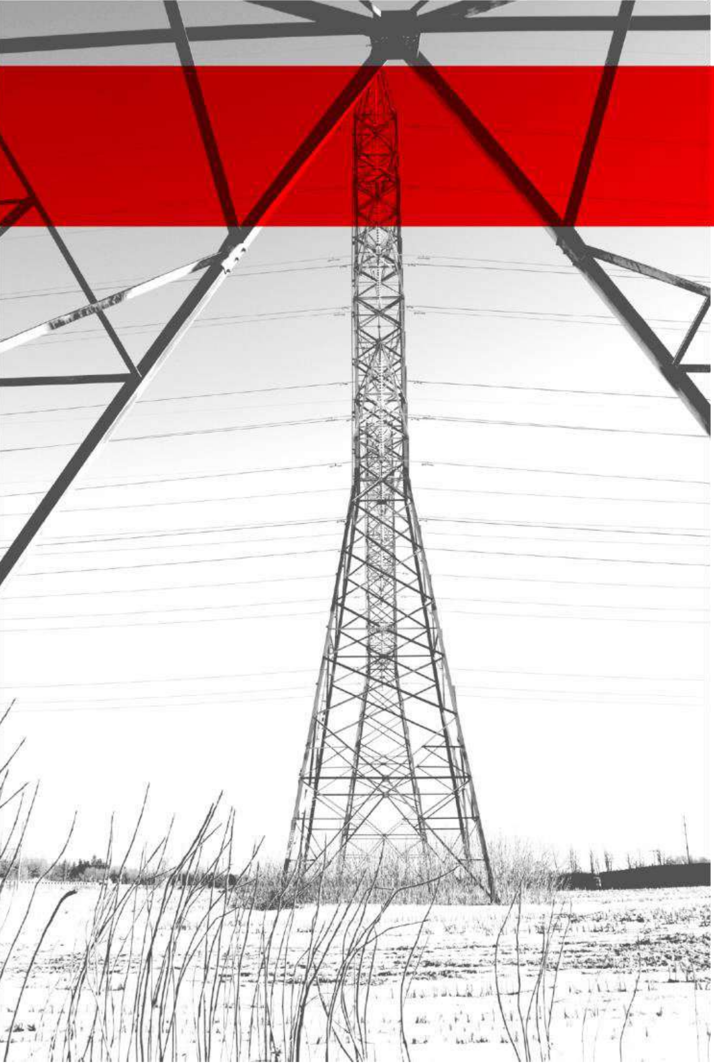
- Accomplish more work for the same dollar amount

- Success means:
  - Grow by focusing on core capabilities
  - Be a top-tier operator delivering safe & reliable power cost-effectively

LINES AND FORESTRY

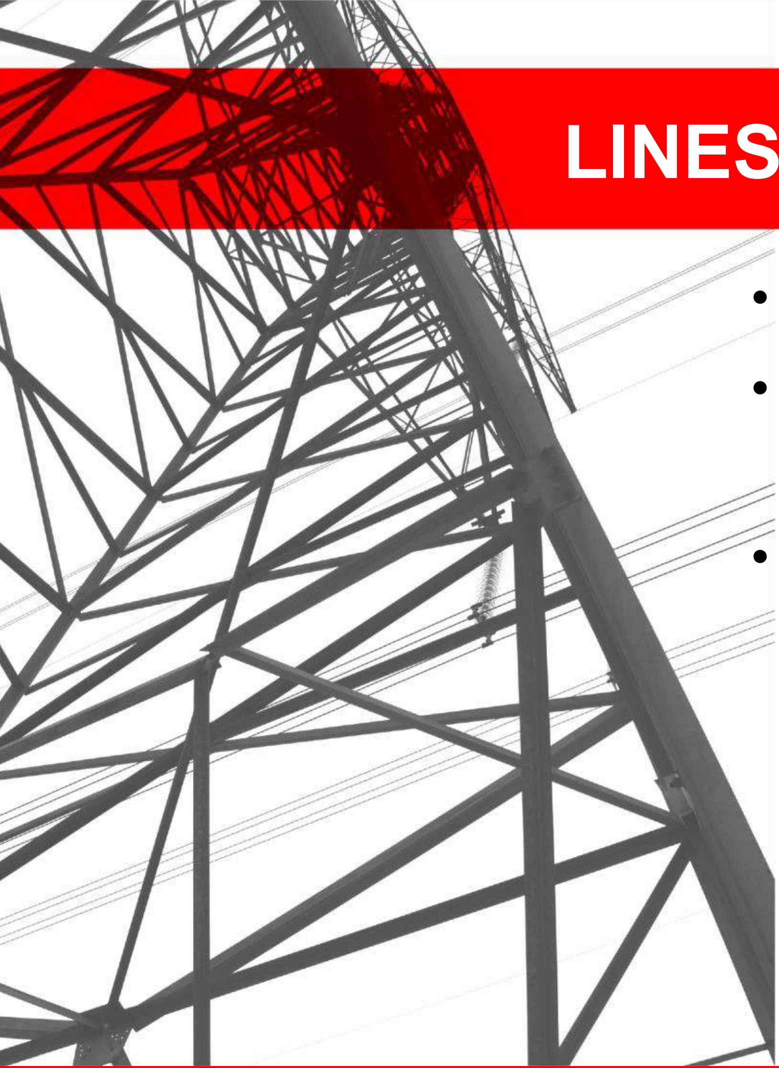
FORESTRY

- We are the only utility in North America with an in-house Forestry division
- Hydro One Forestry Services trims or removes over one million trees per year, managing Hydro One's Transmission and Distribution rights of way
- Largest single controllable OM&A cost at Hydro One.



FORESTRY INITIATIVES

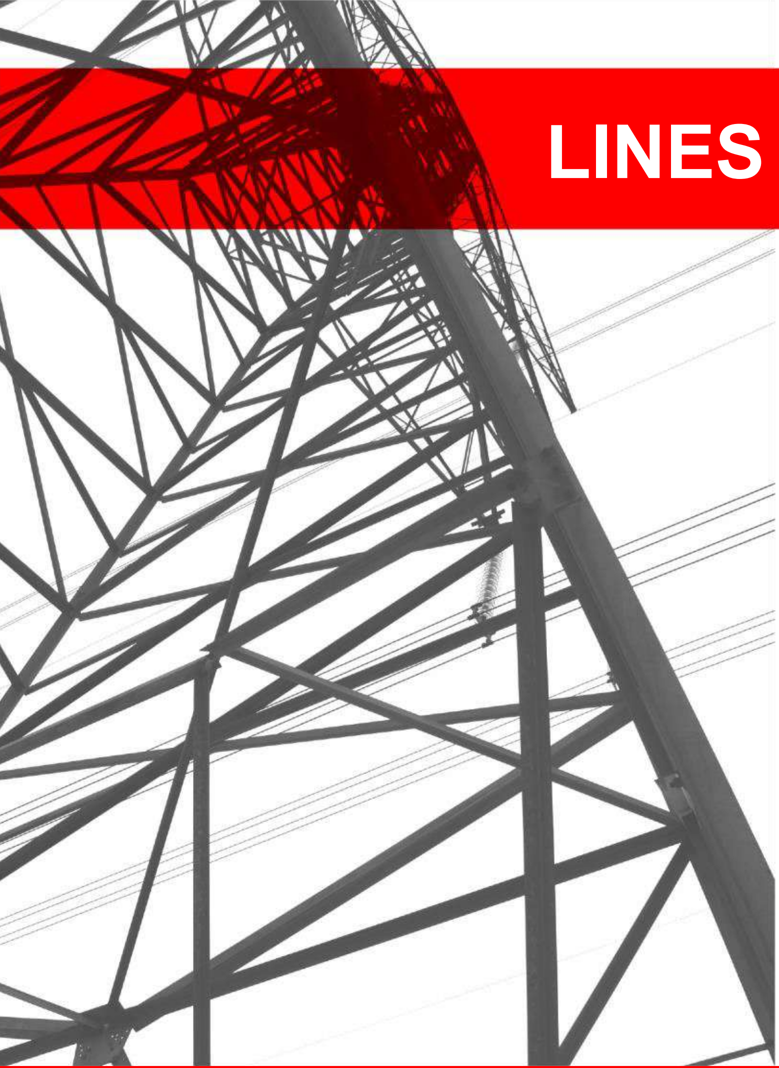
- Brush Control Optimization
- Customer Notification Optimization
- Inclement Weather Initiative
- Muskoka-Parry Sound Initiative
- Switching and Grounding Initiative



LINES

- Largest work group in the Company
- Many different types of work
  - Mix of Capital and O&M
- Landscape:
  - Unique challenges due to scale of operation, varied geography and rural customer base
  - No obvious comparator although OEB and others compare us to “peer” utilities

LINES INITIATIVES



- Cable Locate Outsourcing
- Perform
- Move to Mobile

STATIONS
AND OPERATING

GRID CONTROL CENTER

Operating the Transmission and Distribution systems of Hydro One

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Cable Locates Process

Objective: Improve workflow, streamline processes to efficiently manage cable locates and increase safety awareness for transmission Cable Locates.

Goal: Create a ticketing tool/application to streamline the process to efficiently manage cable locates. Also, to reduce safety incidents related to transmission cable locates.

Benefits:

- Improved workflow processes with HOULTT (Hydro One Underground Locate Ticket Tool) ticketing system; Moved away from paper based process
- Improved communication with Ontario One Call
- Improved communication between all internal and external LOBs
- Improvement in safety with consistent tool and processes
- Improved with consistent standards and procedures

Initiatives:

- HOULTT (Hydro One Underground Locate Ticket Tool)
- Ticketing tool designed and implemented in house to create efficiencies, increase productivity and increase safety
- Predecessor process was paper based, fax driven, etc....

System Event Investigations and Operating Experience

Objective: Investigate system events to determine what occurred and identify any corrective actions with the intent to make improvements to existing processes and procedures. Hydro One shares this Operating Experience and lessons learned with other external entities to benefit the industry. Hydro One also benefits from industry Operating Experience and lessons learned to ascertain if the same conditions or risks are present within Hydro One and to initiate the appropriate mitigation.

Goal: Reduce the number and impact of system events through the monitoring and completion of lessons learned and action items.

Benefits:

- Increased reliability and power quality to customers
- Productivity and efficiency improvements resulting from review and implementation of industry experience and lessons learned
- Apply industry best practices to reduce recurring events

Outcomes:

- Number of System Event Investigations is declining indicating a positive impact to event reduction
  - 2012 – 22; 2013 – 13; 2014 – 13; 2015 – 7; 2016 – 3 (YTD)
- Number of System Event Investigation action items:
  - 415 action items completed since 2012
- 2016 Operating Experience (YTD):
  - Disseminated and shared 42 industry reports internally to Hydro One
  - Produced and shared 6 System Event Reports externally (includes 3 reports from 2015)

Reducing the Impact of Planned Outages on Large Customers

Objective:

- Use better planning to reduce the impact of planned outages on Hydro One customers
- Where possible, schedule outages to coincide with customer shutdowns

Goal: 20% reduction in outage cancellations in 2017

Benefits:

- Reduced impacts on customers by sharing Hydro One capital and maintenance plans
- Improved accuracy for 12 month outlook, providing improved long range
- Reduced costs due to switching and workgroup efficiencies

OPERATING PLANNING GOOD TO GREAT (CONT'D)

Reducing the Impact of Planned Outages on Large Customers

Initiatives:

- Customer Conferences
  - Long term plans to bundle outages with various Hydro One workgroups
  - Customer conferences to scheduling outages that coincide with their shutdowns
  - Weekly updates throughout the year
- Provincial Scheduling Tech Training
  - Improved training to maintain and build scheduling skills for all internal workgroups (Stations, Lines)
  - Results in better quality outage submissions
  - Mandatory annual training for all schedulers
- SE-109 (Stakeholder Engagement)
  - IESO driven change that forces long term planning and provides a "System Check" upon submissions
  - Provides early indication of success with an implementation date of October 26th
  - First session of training provided during the first week of November
- NMS Study Tool Improvements
  - Close identified gaps in planning studies leading to cancelled outages

Program Enhancements – 2016 and beyond

Objective: Reduce the costs of training for the Controller and Controller Trainee programs in the Network Operating Division

Goal: To be as efficient and cost effective as possible

Benefits: Reduced costs associated with training

Program Enhancements:

- Reduced the Controller in Training Program from 3 years to 2 years
  - Require 3 year Electrical/Electronic Technologist or equivalent as minimum educational requirements
  - New hires into the Controller In Training Program are able to become full fledged Controllers one year earlier and therefore have a positive impact on schedule and by extension Overtime

- Reduced the number of available training sessions for Controllers by 18 days per year.
  - Assuming 2 Subject Matter Experts from the Control Room complement per training session/day, this represents 24 twelve hour shifts that that will not have to be covered off in the schedule

STATION SERVICES





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WHO WE ARE!

Provide maintenance, commissioning, repair, installation and trouble response services at approx. 290 Transmission Stations, approx. 1006 Distribution Stations and CMS:

- Station Services is a **multi-functional, multi-skilled** team of over 850 trades, technical and support staff
- Engineers, Technologists, Electrical Maintainers, Mechanical Maintainers, Civil Maintainers, Maintenance Inspectors, Welders
- Recognized technical expertise with multi-OEM equipment experience
- 29 staffed locations
- Bruce Power, Pickering, Darlington

CABLE VAULT INSPECTIONS

STRADDLE HOIST

OIL FARM AT CMS

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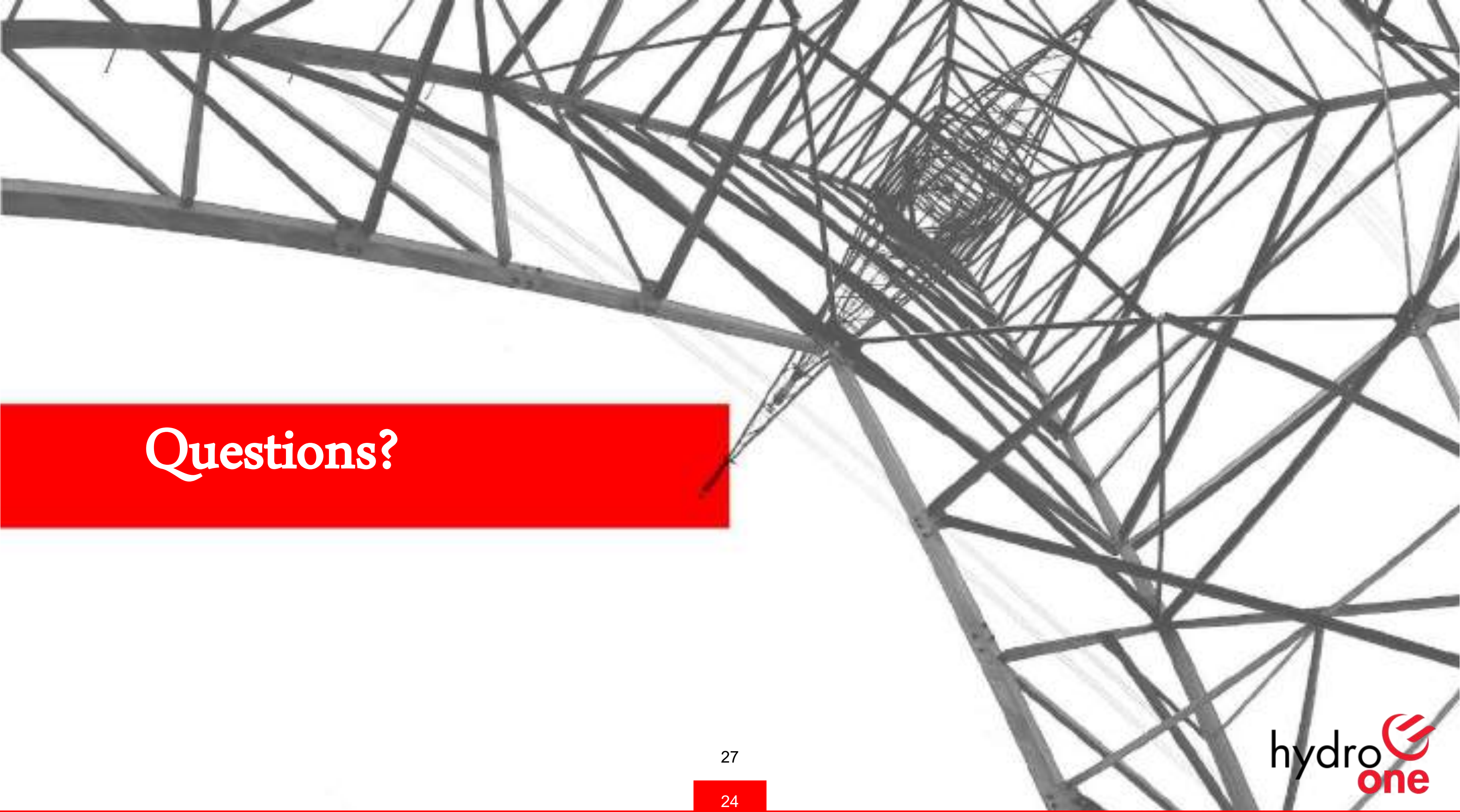
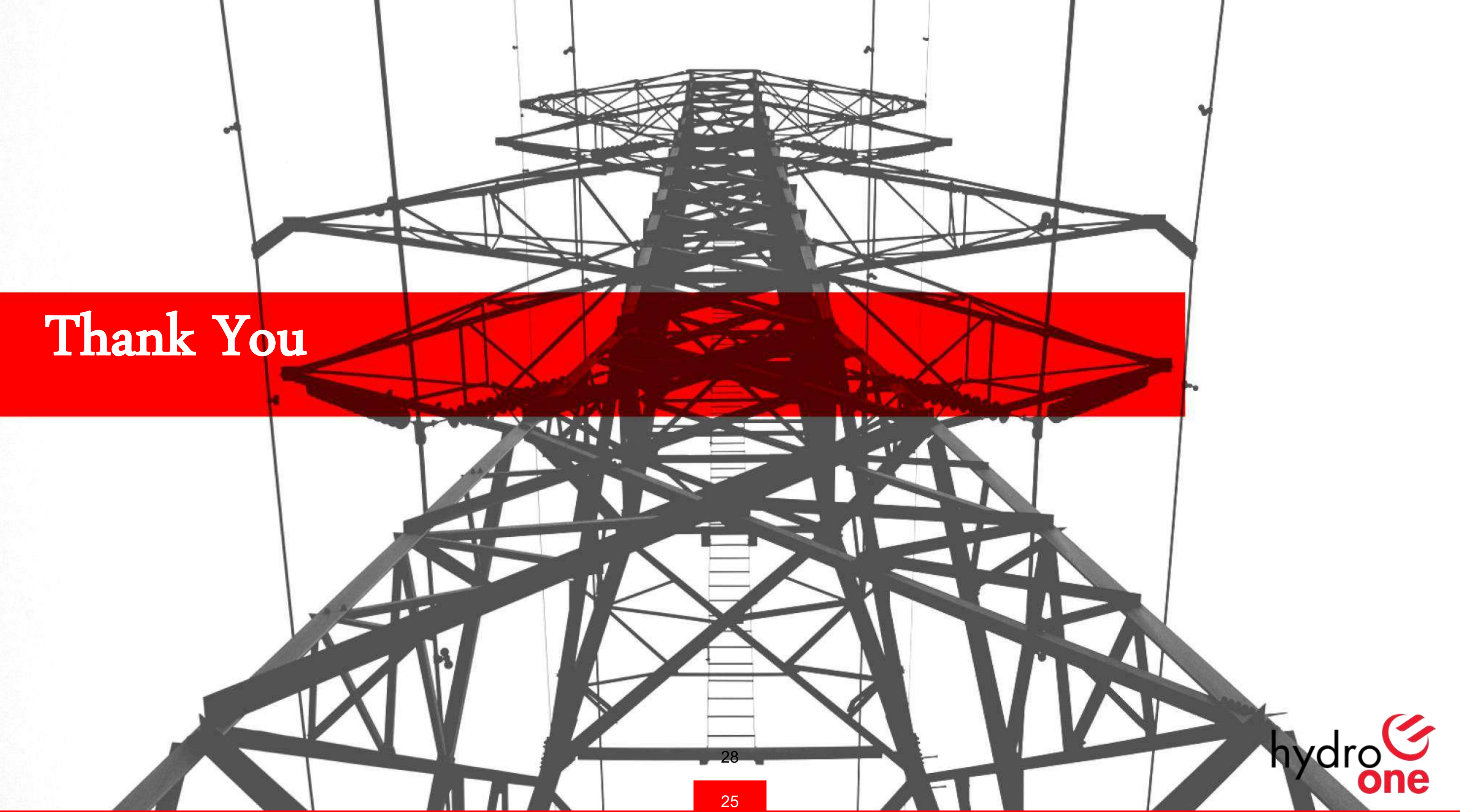


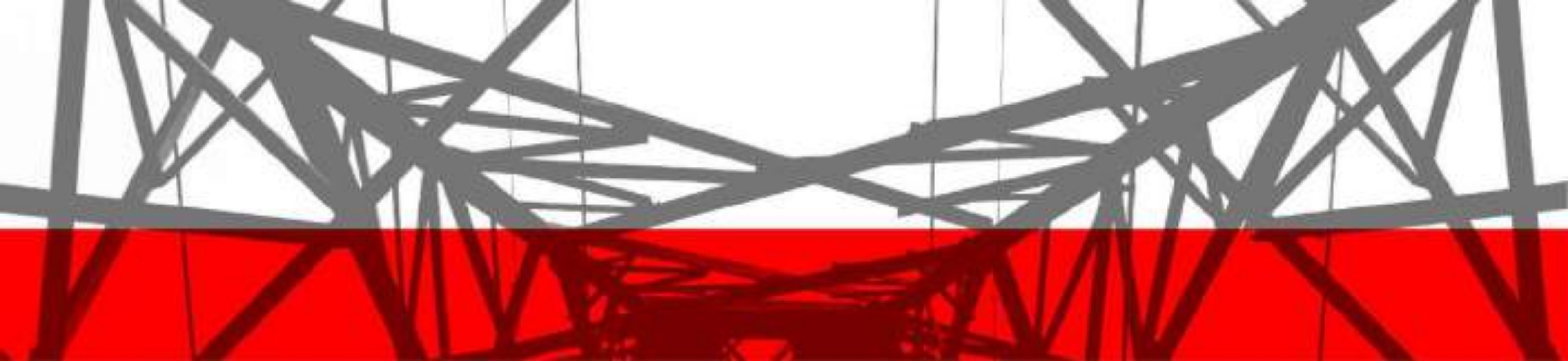
Questions?



Thank You

LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



SECURITY IN THE POWER INDUSTRY

Francis Bradley

Chief Operating Officer,

Canadian Electricity Association

Colin Penny

Senior Vice President, Technology &

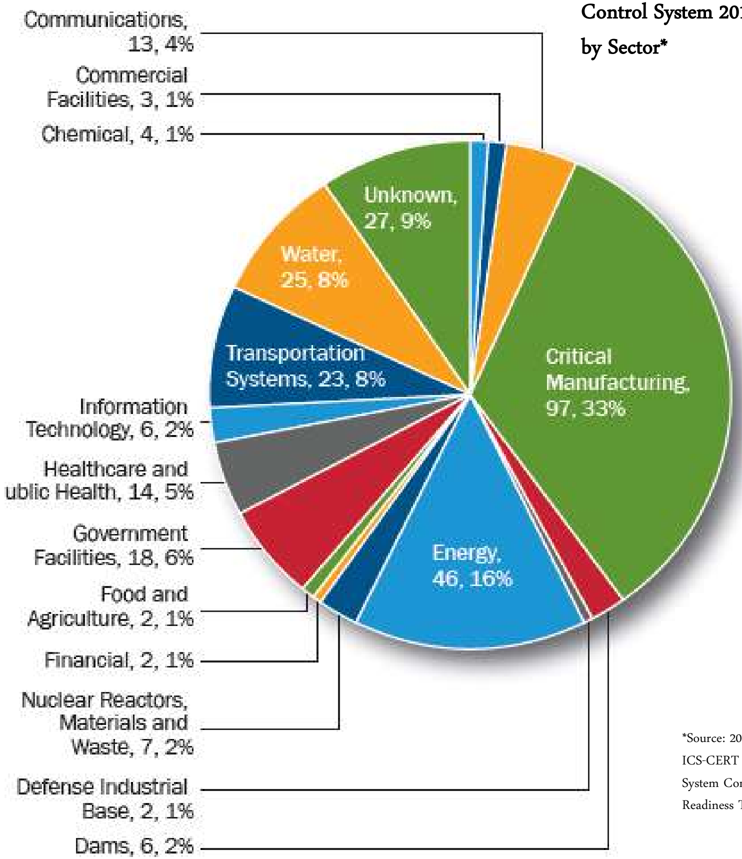
Chief Information Officer,

Hydro One

ELECTRICITY SECTOR CYBER SECURITY

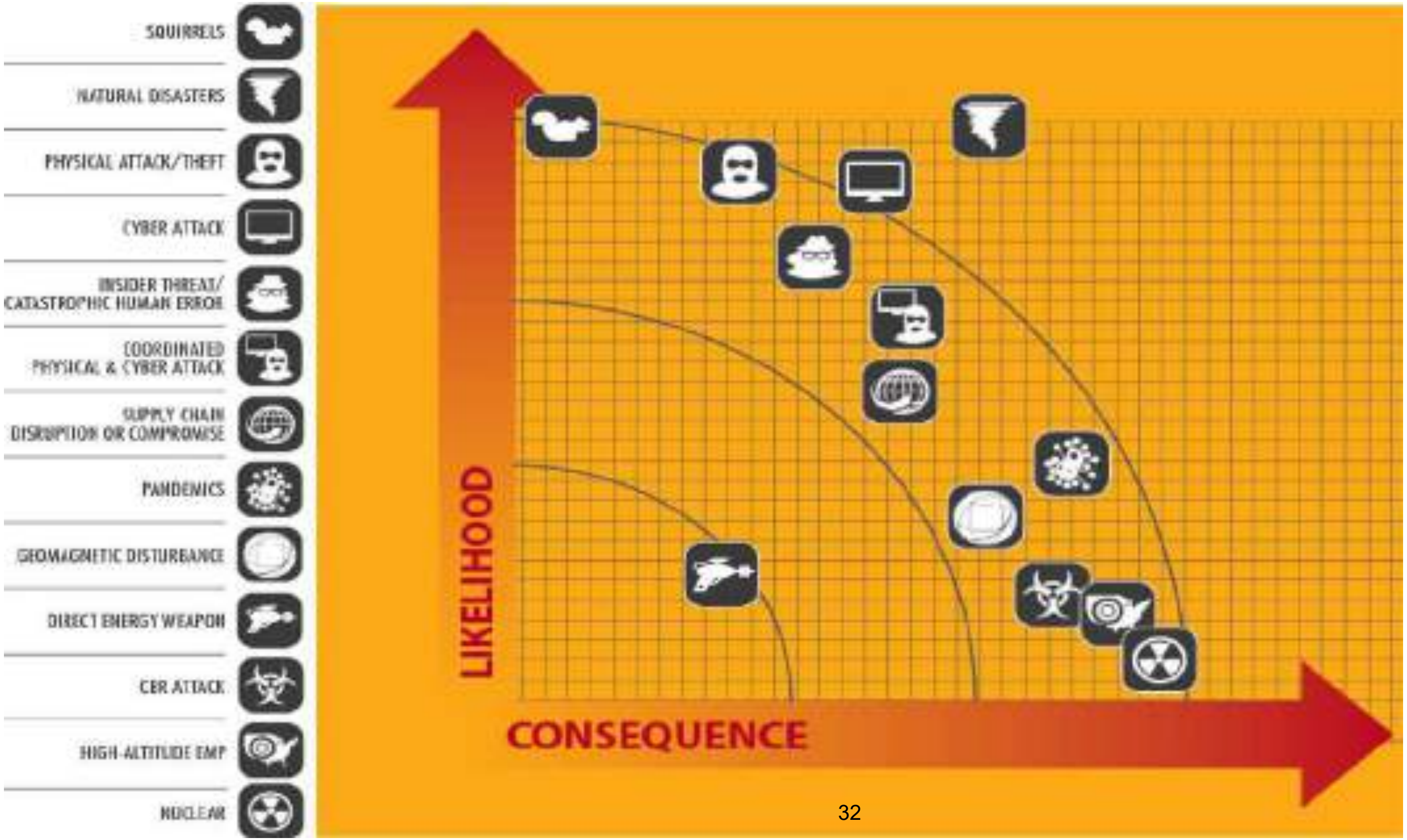
- Power systems are high value targets
- Attacks on the energy industry can cause widespread outages spurring global media attention
- Although state/terrorist sponsored activities are advancing, a disruption from a "lone wolf" attack remains the largest threat

Control System 2015 Incidents by Sector*



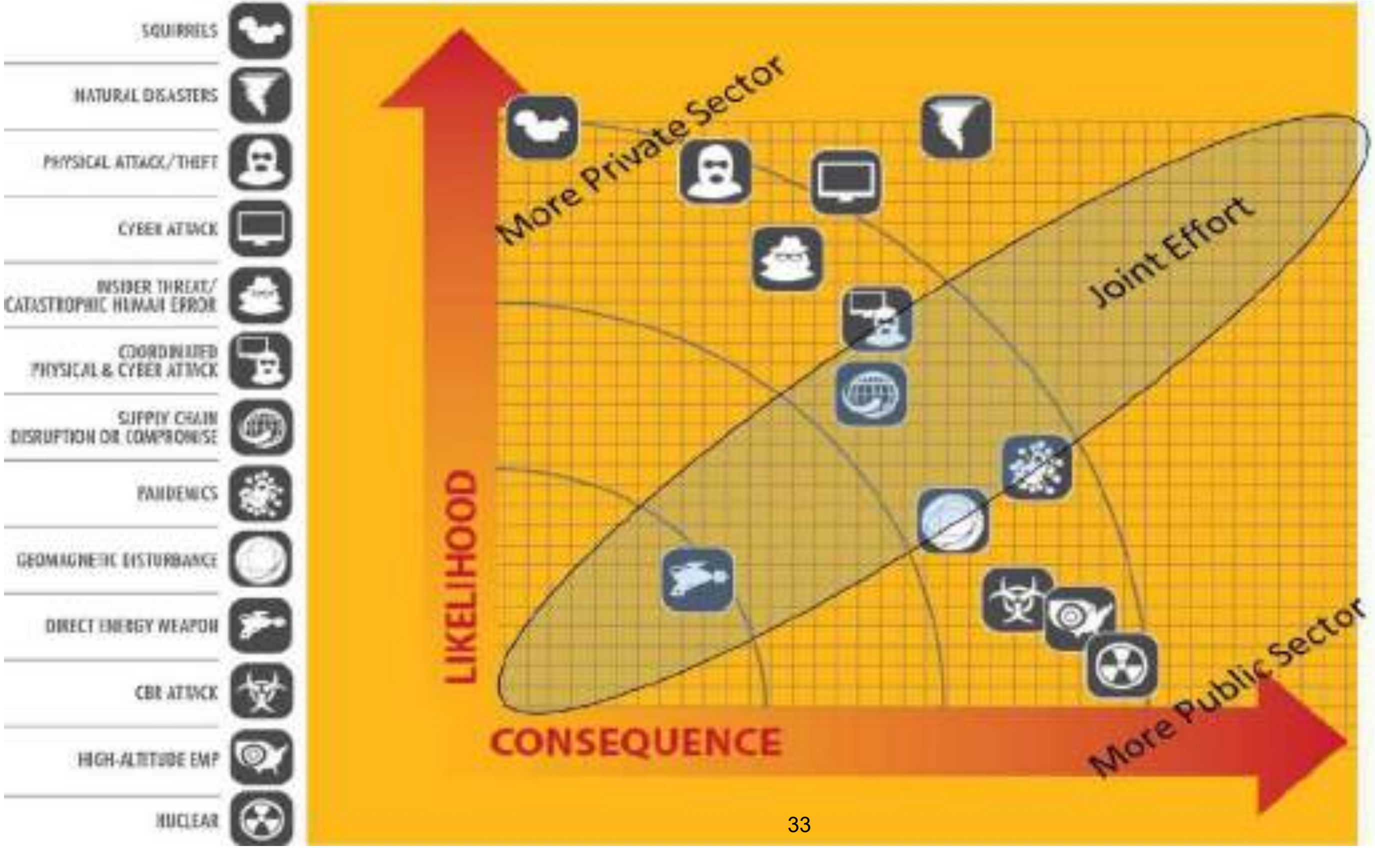
*Source: 2015 Incidents by Sector ICS-CERT – Industrial Control System Computer Emergency Readiness Team

ELECTRICITY THREAT LANDSCAPE



Source: Chertoff Group

THREAT DEFENSE/MITIGATION



Source: Threat mitigation trend from Electricity Information Sharing & Analysis Center

THREAT ACTORS

TOTAL SUCCESSFUL CYBER WAR OPS AS OF 2016.11.07 - 1588

Agent	Success
Squirrel	819
Bird	396
Snake	76
Raccoon	70
Rat	36
Marten	14
China	0
Russia	0*
USA	1

Source: http:/cybersquirrel1

THREATS: UKRAINE ATTACK

12/24/2015

Dear customers!

Dec. 23, 2015, from 15:35 - 16:30, third parties were made illegal entry into information-technological system of remote access to equipment telecontrol substations of 35-110 kV JSC "Kyivoblenergo."

As a result, it was disconnected 7 (seven) 110 kV substations and 23 (twenty three) substation 35 kV. This led to the repayment of about 80,000 different categories of customers on the reliability of electricity supply.

Electricity was restored to all consumers employees of the Company at **18:56** the same day.

We apologize for the situation and thank you for your understanding.

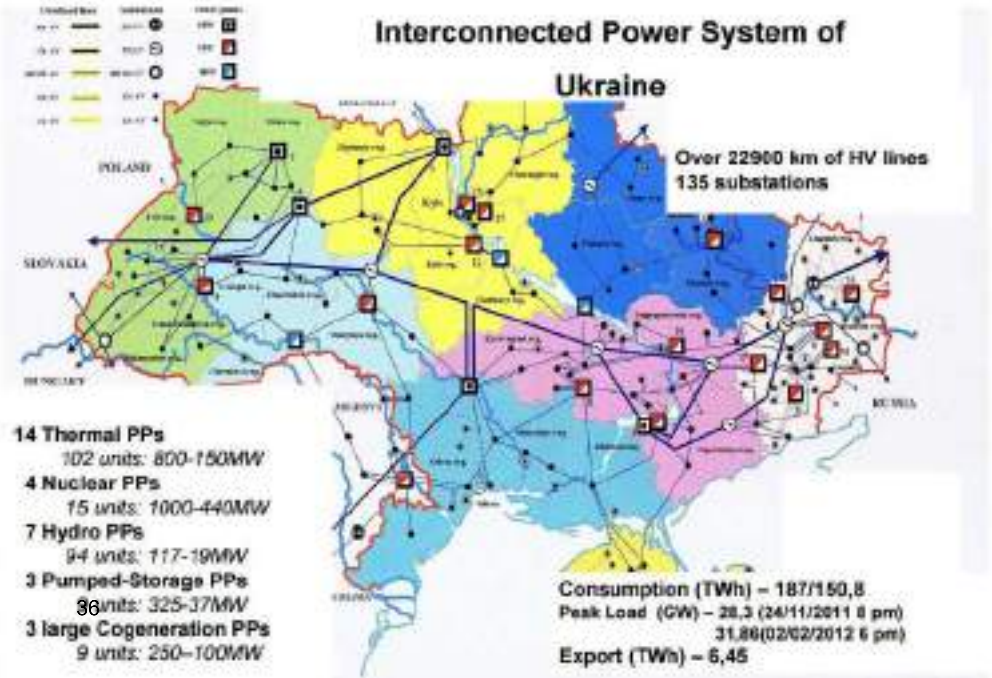
PJSC "Kyivoblenergo"

THREATS: UKRAINE ATTACK

- Ukraine is a nation of about 44 million people
  - Total area of 603,550 sq km, and is just slightly smaller than the province of Manitoba
  - Bordered by Belarus, Hungary, Moldova, Poland, Romania, Russia and Slovakia

- 2012 estimates – Ukraine produced 187.1 billion kWh, with an installed generating capacity of 55.19 million kW

- The country was a net electric power exporter
  - Importing a total of 89 million kWh
  - Exporting 6 billion kWh

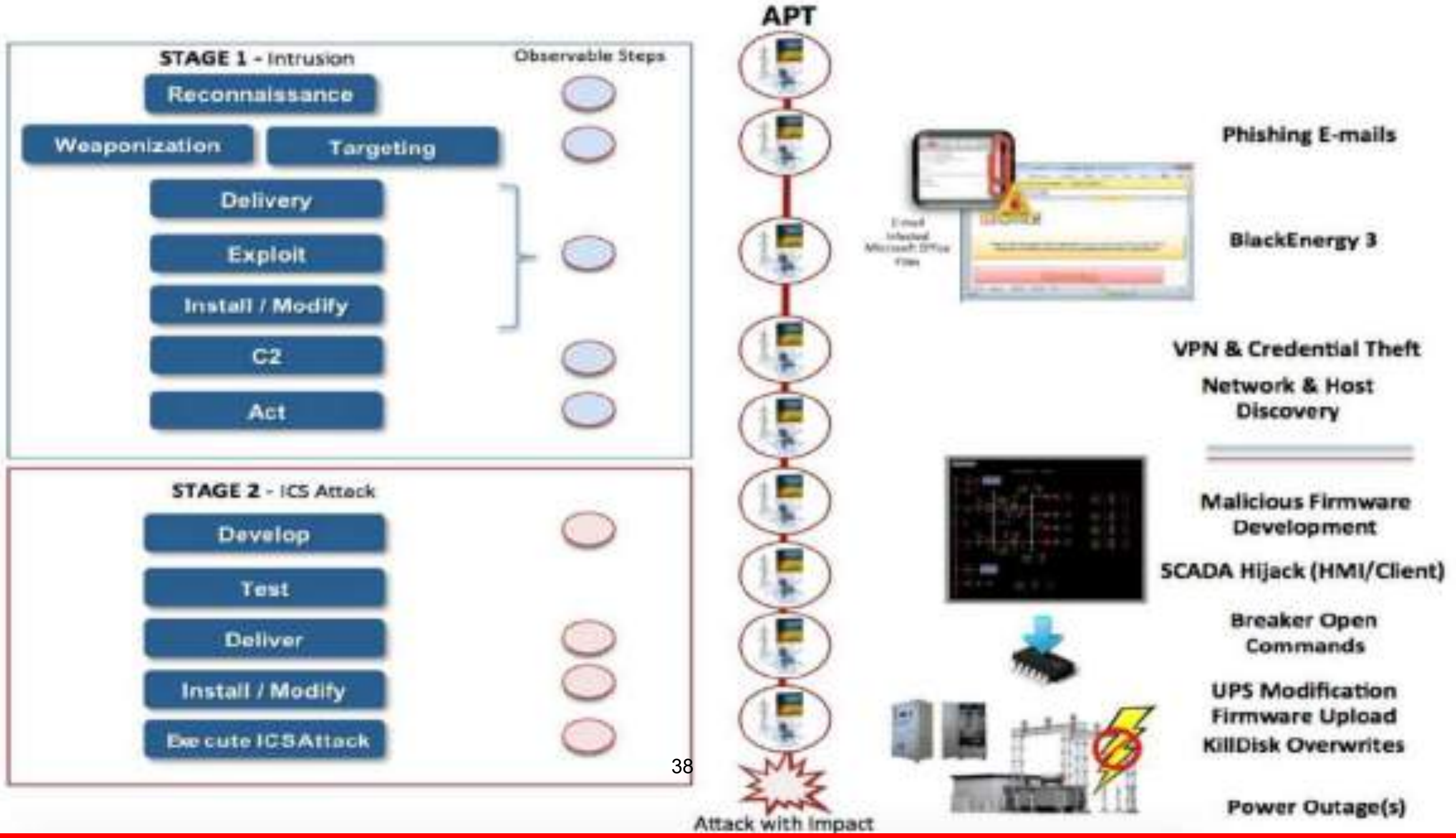


THREATS: UKRAINE ATTACK (CONT'D)

- On December 23, 2015, three Ukrainian power companies (called "oblenergos") experienced an unprecedented cyber attack causing power outages, which impacted over 225,000 customers in Ukraine

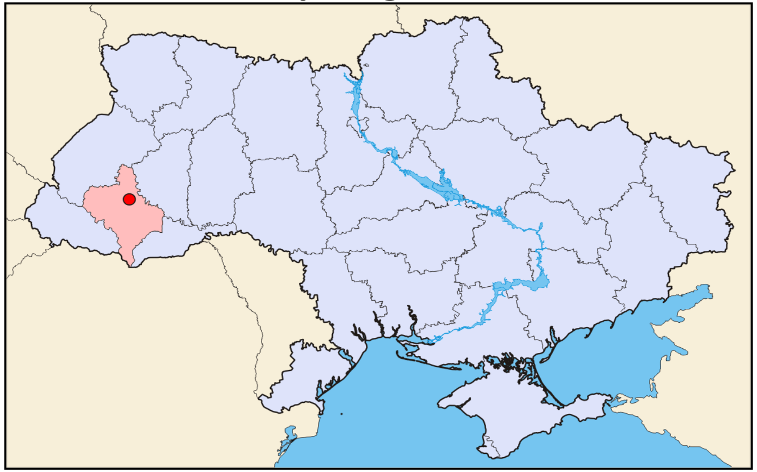
- These attacks were conducted by remote cyber attackers who, leveraging legitimate credentials obtained via unknown means, remotely operated breakers to disconnect power. Within the Ukrainian electrical system,
these attacks were directed at
the regional distribution level only.

ATTACK EXECUTION SUMMARY (KILL CHAIN)



CYBER ATTACK IN THE UKRAINE

Multi-pronged Attack



Dec 23, 2015: Three electricity distribution systems in Ukraine were disrupted, leaving more than 225,000 customers without power for as long as six hours. The incident affected more than 50 substations, and 134 megawatts of load were shed. Simultaneously, a telephony Denial of Service attack on call centers hindered communication — as customers were trying to report their outages.

Hydro One Security Measures

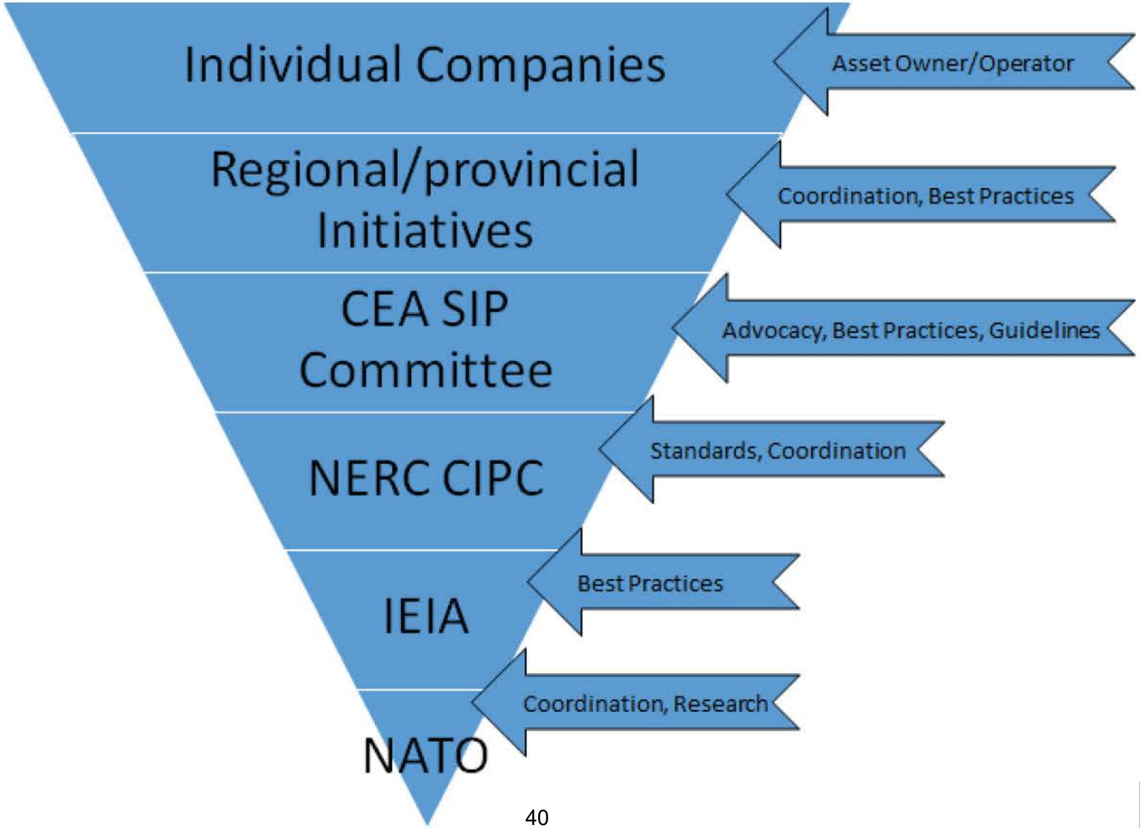
Hydro One and other North American Grid Operators have security controls in place that would have prevented the Ukraine scenario:

Grid control systems separate from enterprise systems

Specific solutions to block malware

Hydro One recently participated in an assessment of Canadian Electric Utilities to review the Ukraine scenario and that our approach is aligned with the Canadian Electric Industry.

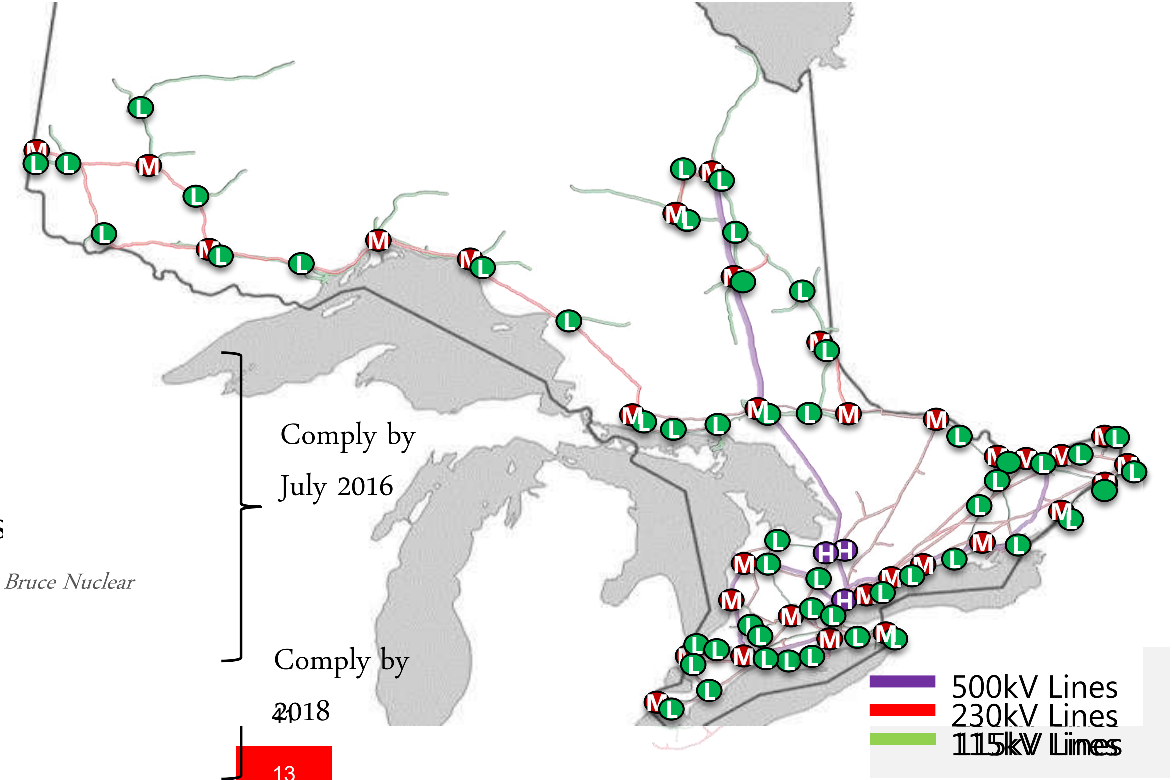
CANADIAN ELECTRICITY ASSOCIATION COLLABORATION MODEL: ADDRESSING SECURITY



The North American Electricity Reliability Corporation (NERC) has developed Critical Infrastructure Protection (CIP) standards. For CIP, controls are scaled to the criticality of the facility

Bulk Electric System (BES)

The electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV or higher.



H High Impact Facilities

Control Centers, Data Centers

M Medium Impact Facilities

500kV Facilities, IESO-identified 230kV Facilities, Bruce Nuclear Protection Facilities, Hub Sites

Comply by July 2016

L Low Impact Facilities

IESO-identified115kV Facilities

Comply by 2018

FRAMEWORK FOR ADDRESSING CYBER SECURITY

Prepare

Predict

Prevent

Respond

Recover

Restore

CYBER SECURITY: OPERATIONS

- Hydro One monitors systems for operational and security events 24x7 at the Ontario Grid Control Centre and Telecom Operations Centre
- We continuously look for opportunities for improvement by monitoring the quality of security processes through internal audits, exercises and external assessments. We use expert security organizations to perform many of these activities

Mock audits by expert organizations:
Compliance related reviews for NERC regulations

Table top incident response simulations:
Internal scenario driven exercises to identify process gaps and maturity levels across the company

Annual vulnerability assessments:
Compliance requirement to annually scan critical systems for known vulnerabilities, confirm system configuration and documentation

IESO Market Assessment & Compliance Division (MACD) reviews:
Audit authority in Ontario mandates a compliance program and reporting obligations

White Hat exercises:
Hydro One has been aggressive in performing reviews of control effectiveness and personnel with ongoing multi-year White Hat exercises

Ontario Provincial Police site threat risk assessments & exercises:
Comprehensive security reviews at critical facilities; advises on internal physical security standards and OPP response plans at our facilities

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BUSINESS CONTINUITY

- Hydro One takes a proactive approach to mitigate risks to our transmission and distribution system and to the continuous delivery of our critical functions
- We have an experienced and exercised Emergency Response Organization trained to coordinate our emergency response regardless of cause

Preparing for Emergencies
Continually monitoring weather to implement preemptive measures at our stations

Mutual Assistance Agreements
Provide mutual aid to and ask public utilities to assist with restoration (Ontario and North America)

Learning from Actual Events
Undertake reviews of actual events and implement recommendations

Fire Tours

Fire Services have been provided with tours of many of our stations across the province

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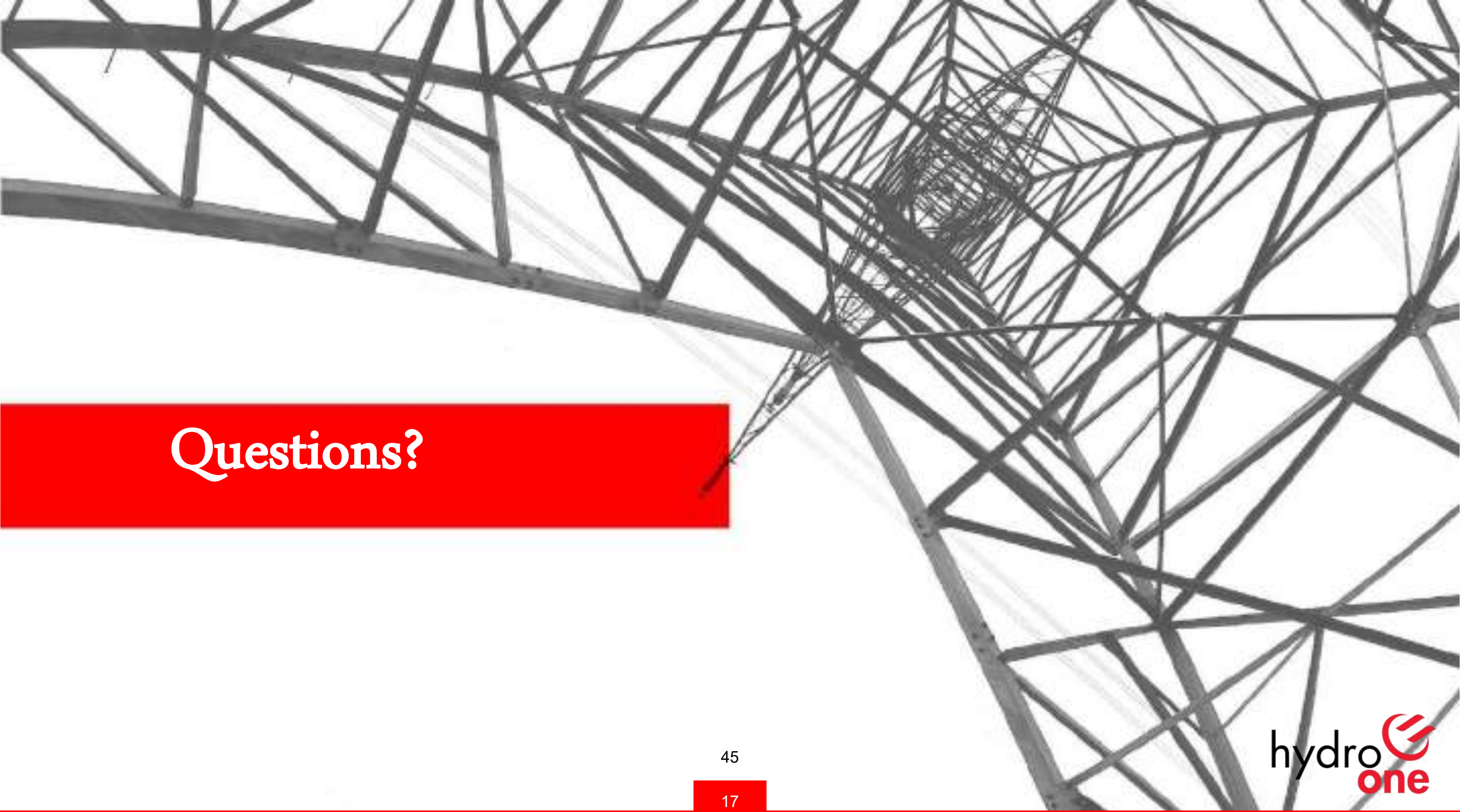
Partnerships

Working proactively with market participants, emergency services, communities, news media and stakeholders

Emergency Response and Business Continuity Plans
Tested annually and full scale exercises
(e.g. GridEx and Polar Vortex)

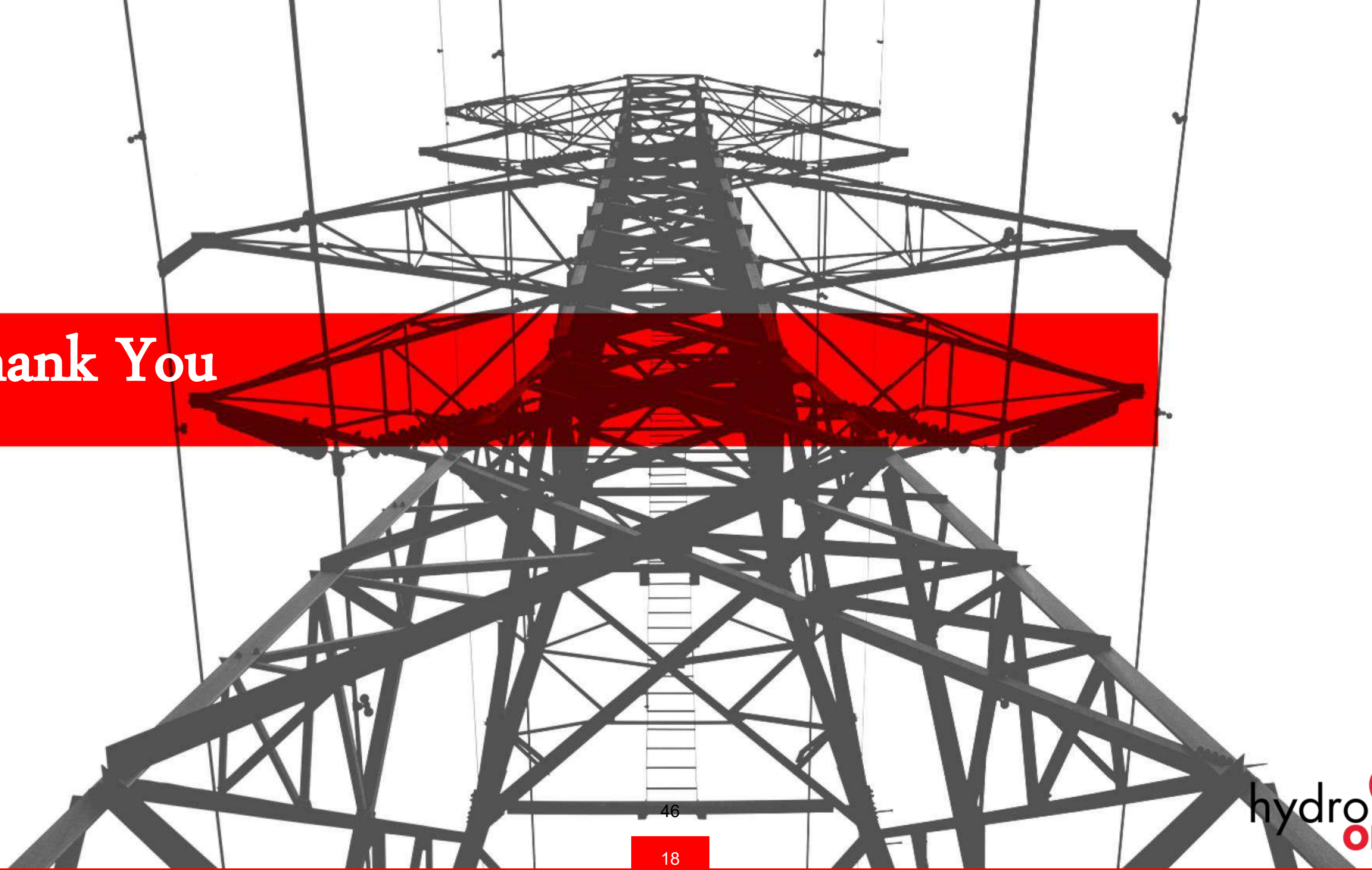
Continuously improve our ability to respond to emergencies
Preemptive strategies to reduce any impact on our system

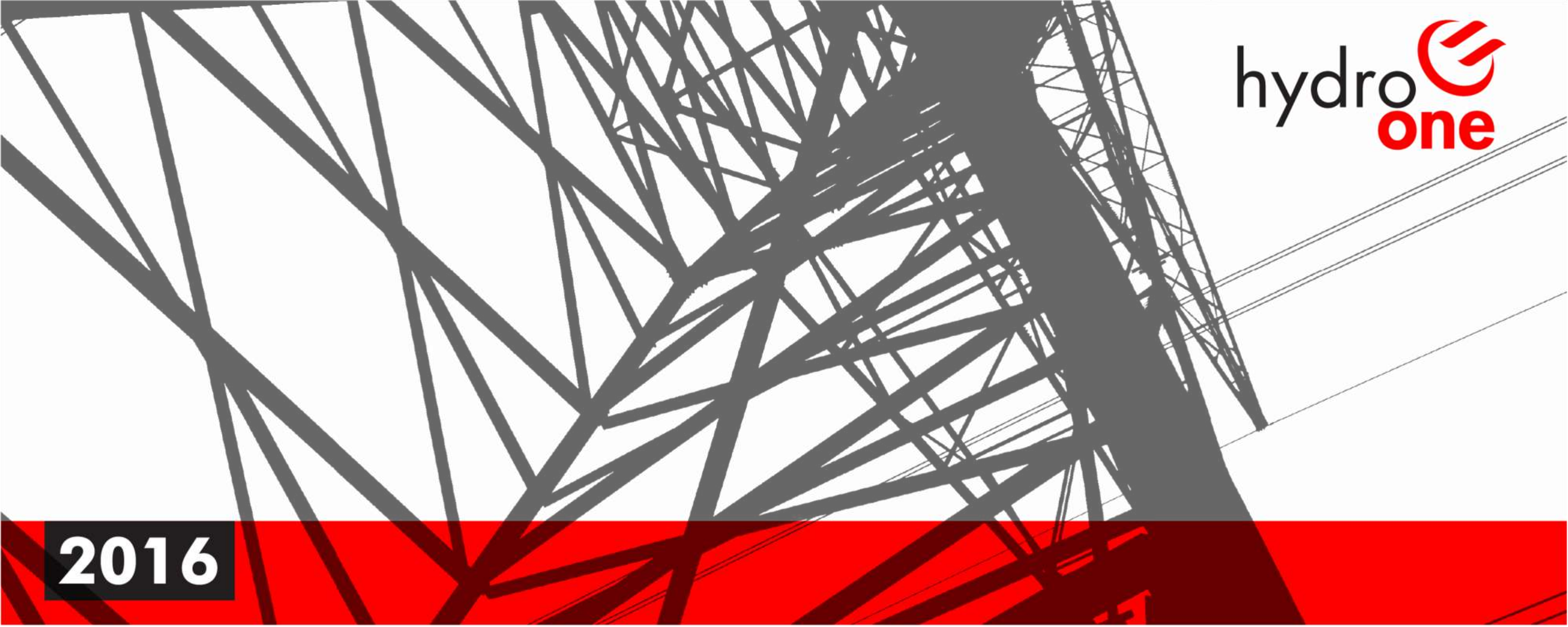
Build Relationships with Police Services
Work with police services across the province on Critical Infrastructure Protection



Questions?

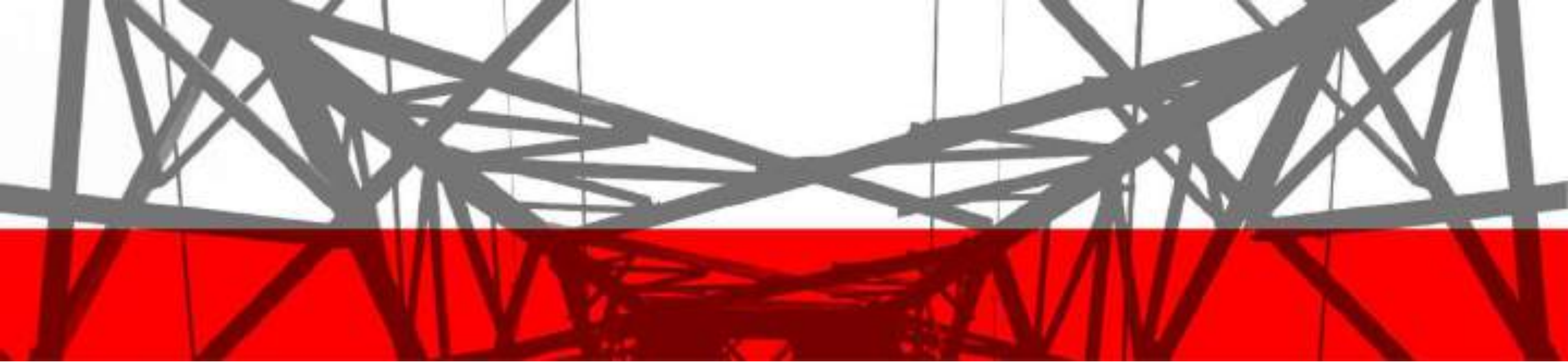
Thank You





LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



TRANSMISSION CUSTOMER ENGAGEMENT & BUSINESS PLAN

INVESTING FOR THE FUTURE

Graham Henderson

Director, Key Account Management

Hydro One

Scott McLachlan

Director, Planning Optimization

Hydro One

CONFIDENTIAL AND FORWARD-LOOKING INFORMATION

CONFIDENTIAL INFORMATION

In this presentation, "Hydro One" or "the Company" refers to Hydro One Networks Inc. and its affiliates, taken together as a whole.

In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of Hydro One is intended only to illustrate past performance and is not necessarily indicative of future performance.

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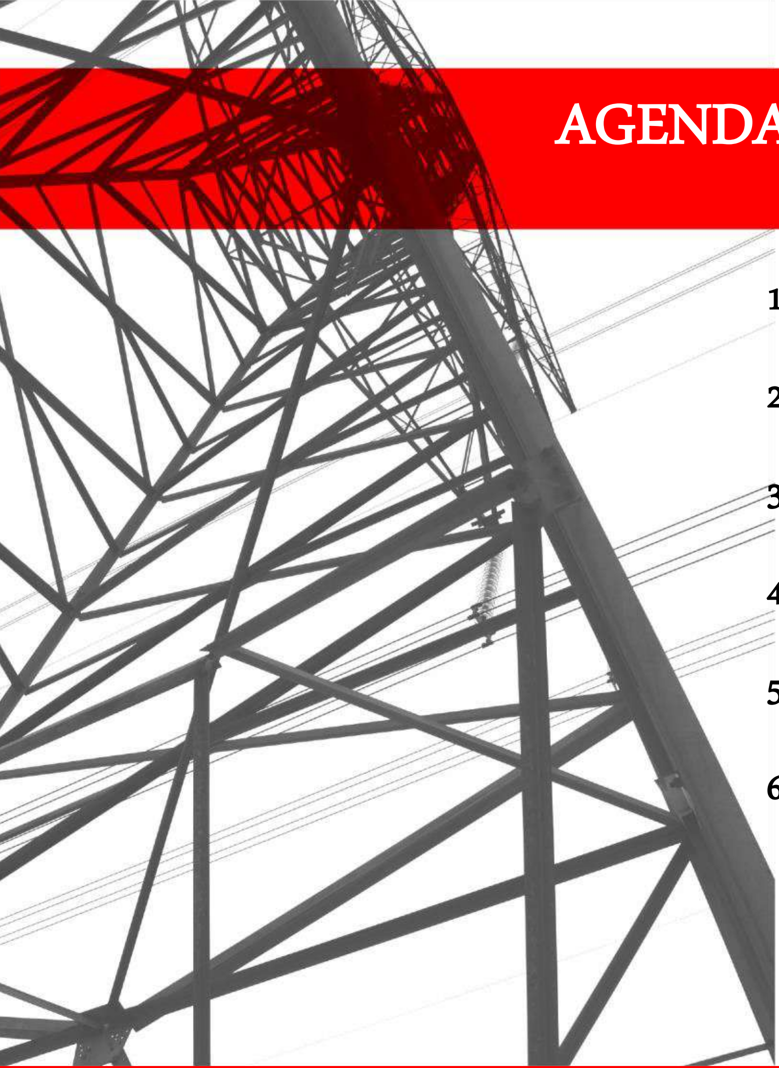
This presentation contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements regarding expected or projected capital and development expenditures, the timing of these expenditures and the Company's investment plans; the use of customer feedback from the consultation process and its impact on the Company's investment plans; the impact of future investments on customer risk, reliability performance and risk, and service interruptions; statements about asset condition, the average ages of critical assets, and their future expected condition; statements about types of asset replacements and their expected associated costs; anticipated rate impacts; and statements about illustrative scenarios and their impact on capital spend, expected outcomes, rates, changes in risk profile according to asset class, and increased or decreased system risk impact.

Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target", "project" and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this presentation is based on a variety of factors and assumptions. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One's business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are: the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned; the risk of public opposition to and delays or denials of requisite approvals and accommodations for the Company's planned projects; the risk that the Company is not able to arrange sufficient cost-effective financing to fund capital expenditures; the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner; the risk that the Company's Board of Directors may not approve the projected expenditures; and the risk that the regulator may alter or deny approval for requested investments and recoverability in rates.



AGENDA

1. **Introduction:** Engagement Strategy

2. **Review:** System Performance (Reliability)

3. **Review:** Investment Scenarios (Illustrative)

4. **Review:** Summary Report (Ipsos – Third Party)

5. **Discussion:** Submitted Plan (i.e. Rate Impacts)

6. **Discussion:** Future Engagement (Feedback)

WHO WE ARE AND WHAT WE DO

Hydro One

is one of the largest transmission utilities in North America

In 2015, Hydro One transported 137 TWh of electricity

- Hydro One's transmission customers include 47 transmission-connected local distribution companies (LDCs), Hydro One's distribution system, and 90 large industrial customers directly connected to the transmission system.
- Hydro One's transmission system totals approximately 292 transmission stations and approximately 29,000 circuit kilometres of high-voltage lines, operating at 500 kV, 230 kV or 115 kV. It represents ~$12B in assets.
- The transmission system is linked to the five adjacent jurisdictions: Manitoba, Minnesota, Michigan, New York and Quebec.
- It must comply with standards established by the North American Electric Reliability Corporation (NERC).
- Hydro One's transmission operations are regulated by the Ontario Energy Board (OEB) and the National Energy Board (NEB), together with an operating agreement with the IESO.

CONTEXT

Factors Affecting Development of Hydro One's Transmission Investment Plan

- New management and independent Board of Directors
- Better line of sight to specific system risks and new approaches to address certain risks
- Benchmarking suggests that Hydro One's total spending on its transmission system has been less than comparators
- Greater focus on understanding the needs and preferences of customers
- Many types of customer interactions but not specific to Hydro One's investment plan

WE TAKE A RISK-BASED APPROACH TO INVESTMENT

We are accountable to plan, operate, build, and maintain an affordable, robust and flexible transmission system that serves Ontario's needs and meets our obligations as part of the North American grid

Our investment plan identifies, prioritizes, and schedules the investments we make in our system.

We aim to create value by:

- Ensuring our investment plan considers and reflects the needs and preferences of our customers by achieving a balance between managing reliability risk, service and cost
- Recognizing every dollar we spend comes at a cost to our customers and the people of Ontario
- Making prudent, cost-effective, short and long-term investments to meet the electricity needs of Ontario now and into the future
- Addressing emerging risks of our system, and always looking for ways to economically extend the life of existing transmission assets
- Being innovative by adapting new/proven technologies, equipment and processes that contribute to the efficiency of our operation

OUR ENGAGEMENT STRATEGY FOR CUSTOMER INPUT

Development of Transmission Investment Plan

for 2017 and beyond

This investment plan in turn, underpins our **Transmission Rate Application** to the OEB

- Increased focus on customers resulted in a decision that development of the Transmission Investment Plan would include customer input
- Our Investment Plan would be based on our customers' needs and preferences, our analysis of assets' needs and of our ability to resource, schedule and execute work
- All transmission-connected customers would have the opportunity to provide input that would support the development of the Investment Plan
- The approach would be consistent with the OEB's Renewed Regulatory Framework

OUR CUSTOMER ENGAGEMENT PROCESS

Use of Independent 3rd Party to develop and implement Customer Engagement Process

- To ensure an inclusive and unbiased process, a decision was made to use an independent 3rd party to help develop methodology, facilitate discussions and document customer input

- Ipsos was engaged as this independent 3rd party

- Methodology was developed to ensure all transmission-connected customers had the opportunity to provide input:

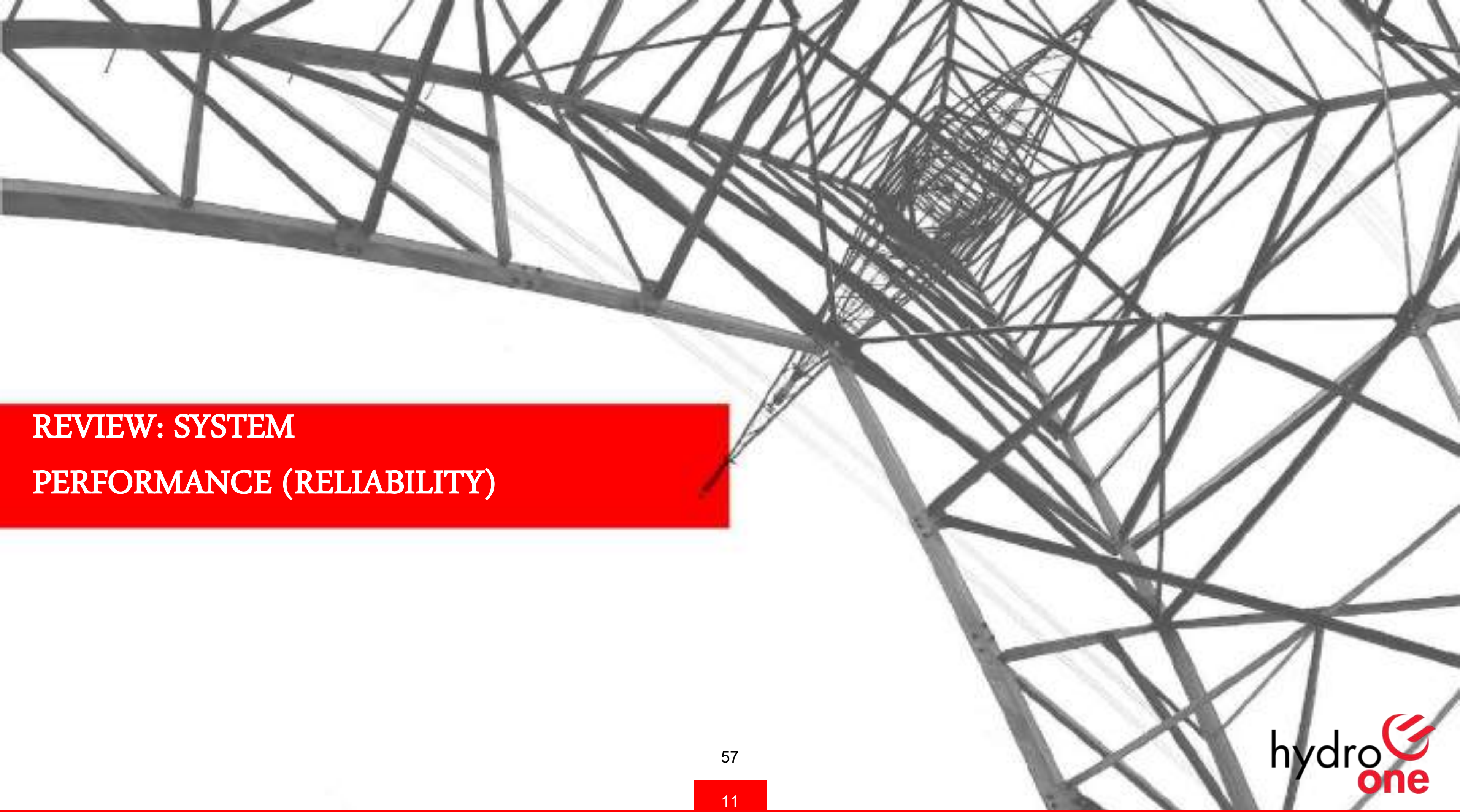
    - One-on-one discussions
    - Larger, professionally facilitated customer engagement sessions held in Toronto, London, Ottawa, Thunder Bay, and Sudbury
    - An online consultation tool

- Consultation materials were developed with a focus on a range of potential sustainment investments and the related impacts to reliability risk and rates.

OUR CUSTOMER ENGAGEMENT PROCESS

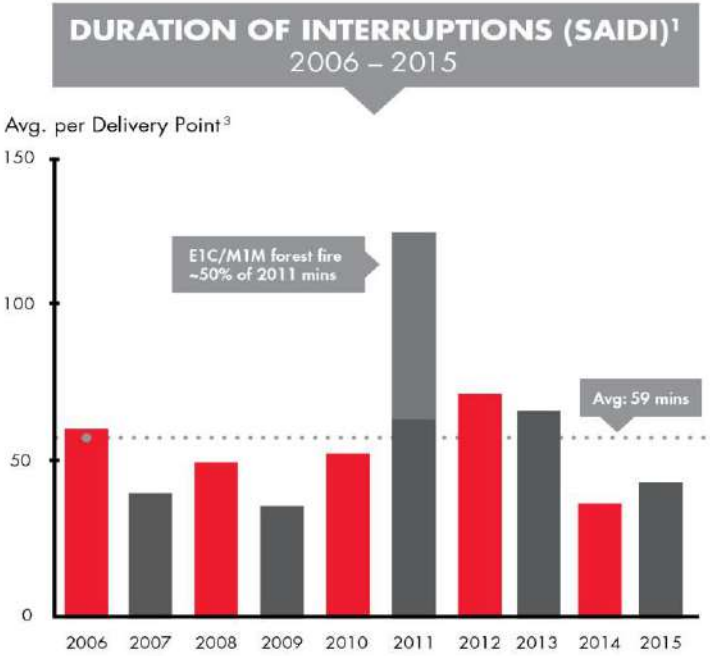
Facilitate and Document Customer Input to inform development of Hydro One's investment plan.

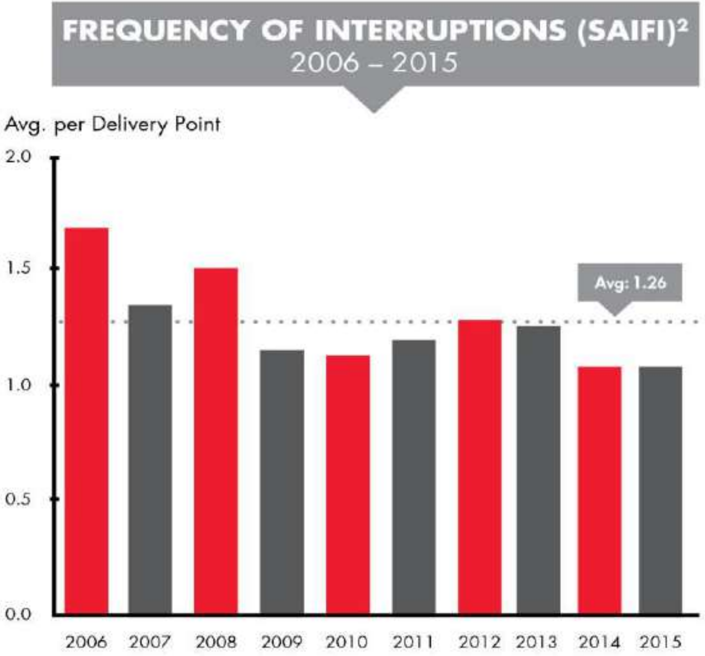
- Consultation materials were developed with a focus on a range of potential sustainment investments and the related impacts to reliability risk and rates
- Customers were provided with identical information regardless of the venue in which they participated
- Ipsos summarized the results from all customer input and wrote a report
- Both the presentation materials and the Ipsos report were filed as part of Hydro One's transmission rate filing



REVIEW: SYSTEM PERFORMANCE (RELIABILITY)

OVERALL TRANSMISSION RELIABILITY HAS REMAINED FLAT



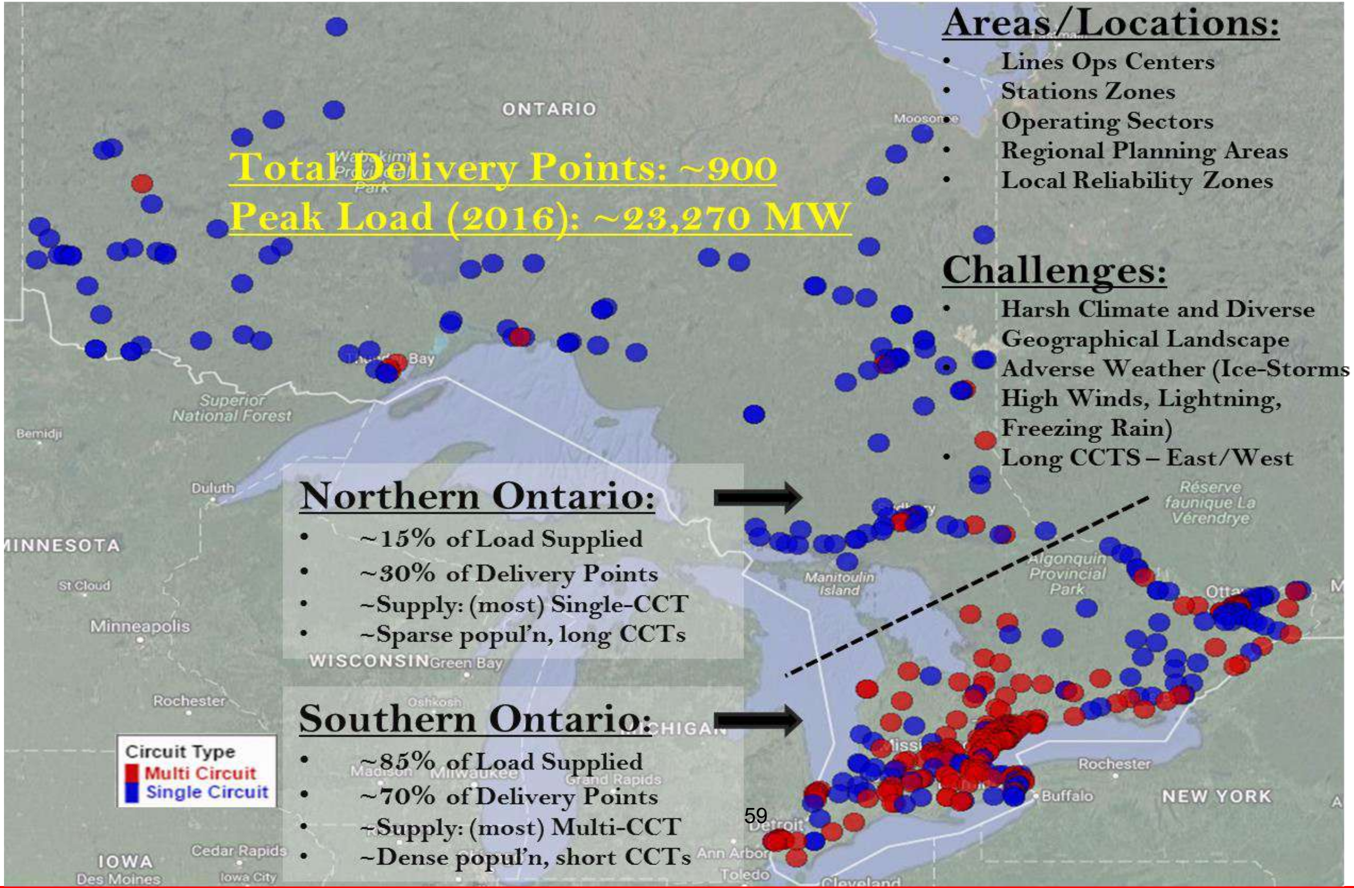


Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes 2013 GTA flood (extreme Force Majeure event - a natural consequence of external forces that are beyond reasonable control).

1. System Average Interruption Duration Index
2. System Average Interruption Frequency Index
3. Interface between the Hydro One transmission system and its load customers. Delivery points consist of: (a) all Hydro One owned step-down transformer stations' low-voltage buses, and (b) stations owned by end-use transmission customers, including LDCs and other transmitters operating at 115kV or higher.

ONTARIO LANDSCAPE: CUSTOMER DELIVERY POINTS

TWO SUB SYSTEMS: MULTI CIRCUIT AND SINGLE CIRCUIT



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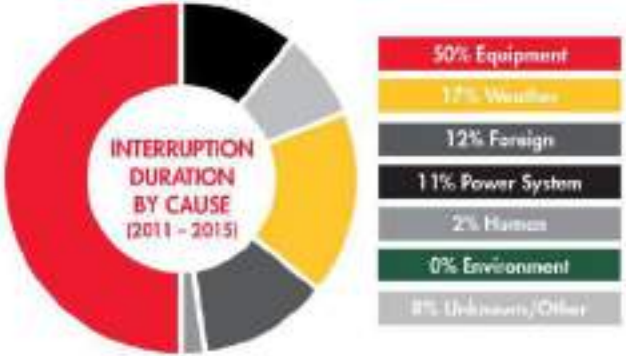
DURATION OF INTERRUPTIONS:
SAIDI CONTRIBUTION BY CAUSE (2011-2015)

Equipment failure is the single largest driver of customer interruption minutes across both systems.

MULTI-CIRCUIT SYSTEM (SAIDI)

KEY FACTS:
• ~70% of delivery points • ~85% of total load
• Located primarily in Southern Ontario

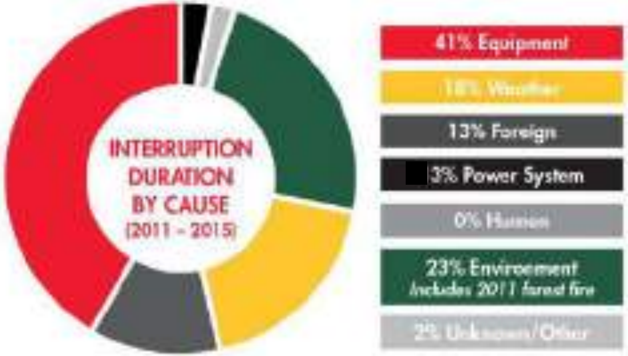


Average interruption duration per delivery point: **10 mins**

Duration of interruptions limited by redundancy in the multi-circuit network

SINGLE-CIRCUIT SYSTEM (SAIDI)[1]

KEY FACTS:
• ~30% of delivery points • ~15% of total load
• Located primarily in Northern Ontario



Average interruption duration per delivery point: **211 mins**

Lack of redundancy drives increased duration of interruptions

Note: Excludes planned interruptions and interruptions due to customer activity. Excludes Force Majeure events.

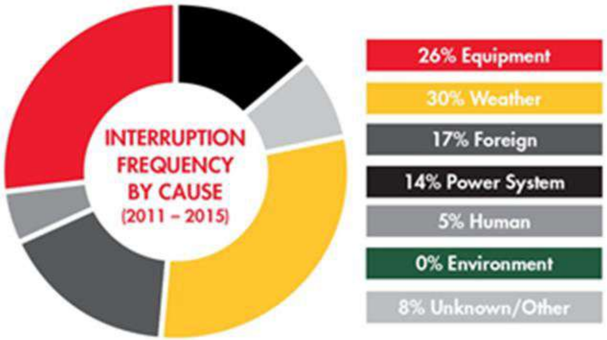
1. D livery points served by sole transmission circuit, leading to limited redundancy; tend to be located in the northern areas of the province.

FREQUENCY OF INTERRUPTIONS:
SAIFI CONTRIBUTION BY CAUSE (2011-2015)

Weather is the single largest driver of customer interruption frequency across both systems.

MULTI-CIRCUIT (SAIFI)

KEY FACTS:
- ~70% of delivery points • ~85% of total load
- Located primarily in Southern Ontario

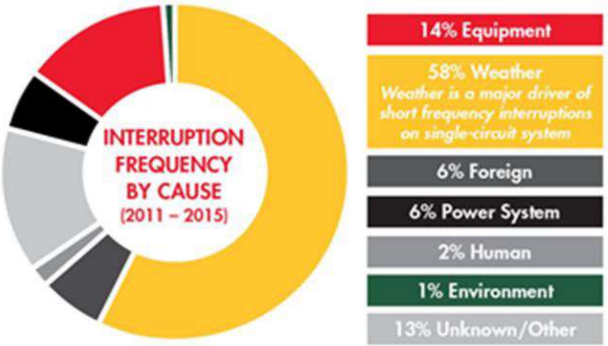


Average interruption frequency per delivery point: **0.27**

Built-in redundancy in the network limits the impact of adverse weather

SINGLE-CIRCUIT (SAIFI)

KEY FACTS:
- ~30% of delivery points • ~15% of total load
- Located primarily in Northern Ontario



Average interruption frequency per delivery point: **3.26**

Lack of redundancy leads to direct impact from adverse weather

Note: Includes both sustained and momentary interruptions. Excludes planned interruptions and interruptions due to customer activity. Excludes interruptions due to Force Majeure events.

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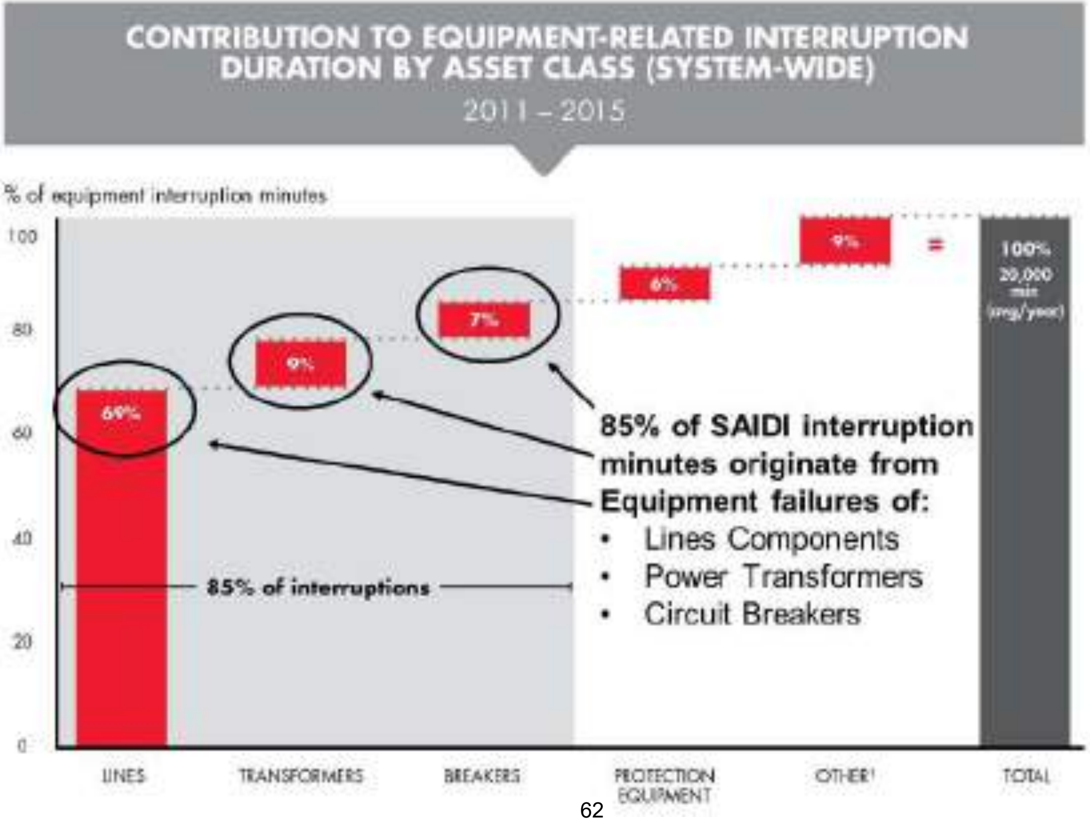
LINES, TRANSFORMERS AND BREAKERS ACCOUNT FOR 85% OF EQUIPMENT RELATED INTERRUPTION DURATION



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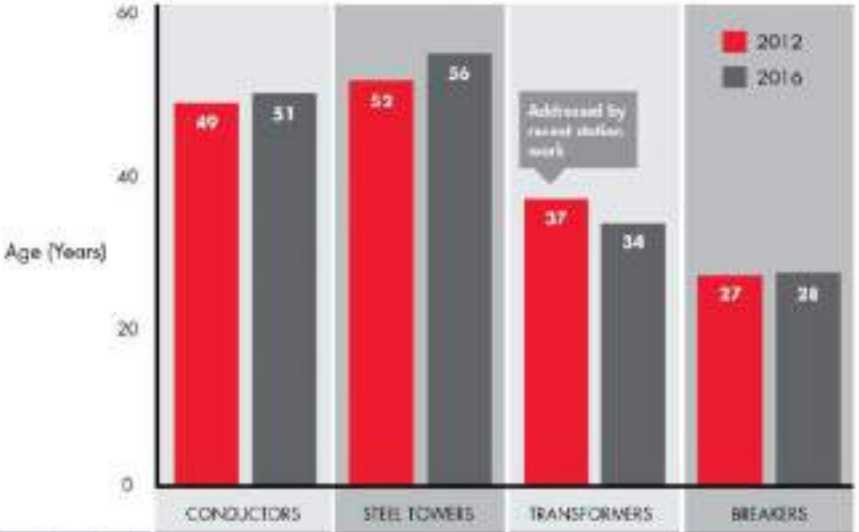
1. Other includes switches, instrument transformers, surge arrestors, system auxiliaries

THE AVERAGE AGE OF CRITICAL ASSETS HAS INCREASED IN RECENT YEARS, AND TESTING HAS IDENTIFIED PRIORITY ASSETS FOR REPLACEMENT

HISTORICAL REPLACEMENT RATE HAS BEEN INSUFFICIENT TO ADDRESS SYSTEM AGING...



	CONDUCTORS	STEEL TOWERS	TRANSFORMERS	BREAKERS
% beyond expected service life[1]	30%	22%	28%	9%
# beyond expected service life	5,800 cct-km	12,000	203	299

+

CONDITION ASSESSMENTS HAVE IDENTIFIED SPECIFIC ASSETS FOR REPLACEMENT.

ASSET	CONDITION
CONDUCTORS	• Based on actual conductor sample testing, 2,300 cct-km of transmission lines known to be at or approaching end of useful life
STEEL TOWERS	• 9,100 steel structures located in known high-corrosion areas based on inventory assessment
TRANSFORMERS	• 31 transformers (4.3%) rated high-risk or very high-risk based on condition assessment
BREAKERS	• ~470 breakers rated high-risk or very high-risk based on condition assessment
INSULATORS	• ~25% of insulators at greater risk of failure • Ongoing testing will determine remaining insulator strength

1. The average time in years that an asset can be expected to operate under normal system conditions.

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HYDRO ONE IS UNDERTAKING
A NUMBER OF ACTIONS TO MITIGATE RELIABILITY RISK

ONGOING ACTIVITY TO ADDRESS RELIABILITY RISK

1 Unplanned Outages: Equipment Failure

The risk due to unplanned outages is being managed by:

- Continued focus on asset condition assessments and data-driven risk analysis
- Assessing maintenance programs and CapEx spend vs. transmission reliability contributions from asset classes
- Evaluating assets that may be run--to-failure candidates (those not directly affecting transmission reliability)

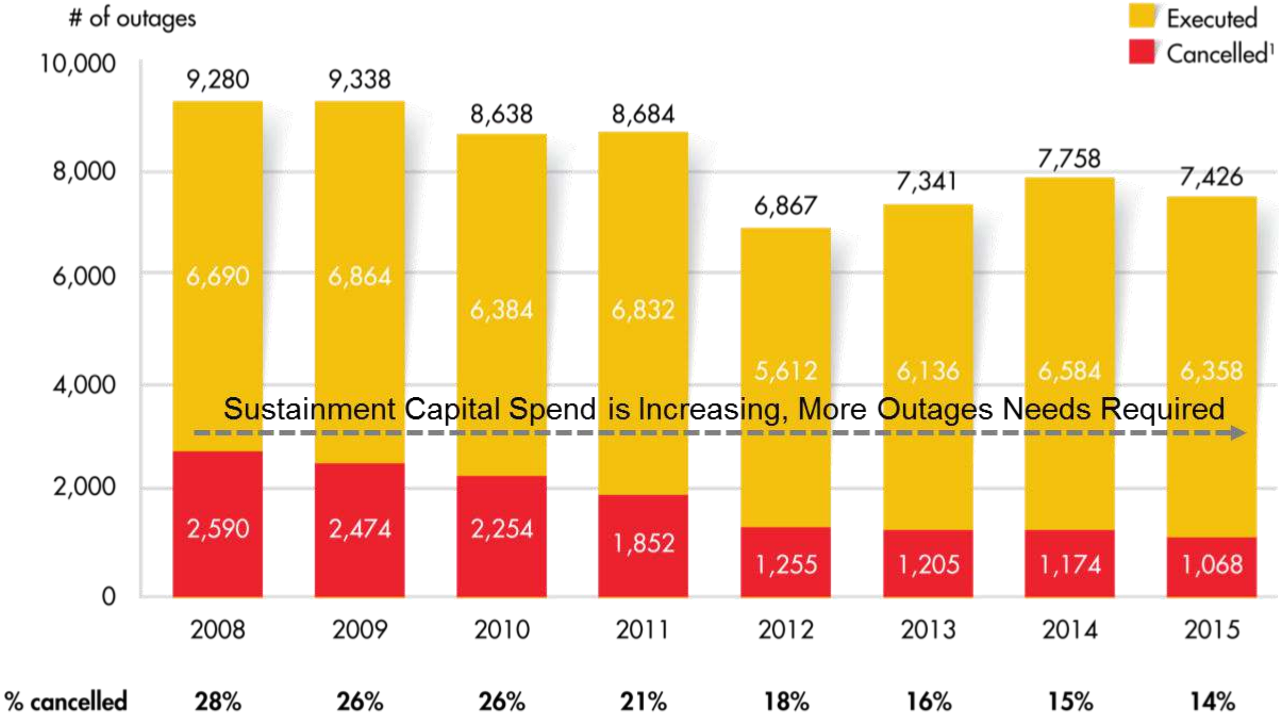
2 Planned Outages: Equipment Repair and Replacement

The risk due to planned outages is being managed by continued prudent planning and work processes, such as:

- Station-centric work approach
- Re-evaluating maintenance program cycles
- Focusing on identifying and enabling work bundling opportunities
- Transmission System Outage Groups process
- Multi-disciplinary planning
- Pre-outage inspections on companion assets (e.g., transformers) for multi-circuit outage requirements

Next slide shows the positive effect these have

HYDRO ONE BULK ELECTRICITY SYSTEM OUTAGES SENT TO IESO (2008 – 2015)



1. Actual number of canceled outages may be lower in reality; some canceled outages are for work no longer required

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SUMMARY OF SYSTEM PERFORMANCE

Hydro One's transmission reliability has remained flat

The **transmission system faces increasing challenges** due to asset condition

1. Outages on the transmission system that interrupt the supply of energy to transmission customers.
2. The average time in years that an asset can be expected to operate under normal system conditions.
3. The removal of facilities from service, unavailability for connection of facilities, temporary de-rating, restriction of use or reduction in the performance of facilities for any reason, including to permit the inspection, testing, maintenance or repair of facilities.
4. Delivery points served by multiple transmission circuits, creating system redundancy; tend to be located in the southern areas of the province.
5. As asset-specific determination based on an asset's condition, criticality, performance, demographics, utilization and economics.

Equipment performance is the largest controllable factor, contributing 42% of system *interruption*[1] minutes. Assets continue to age (e.g., 20% of conductors now beyond *expected service life*[2] of 70 years).

Evidence suggests that underlying reliability risk is increasing:

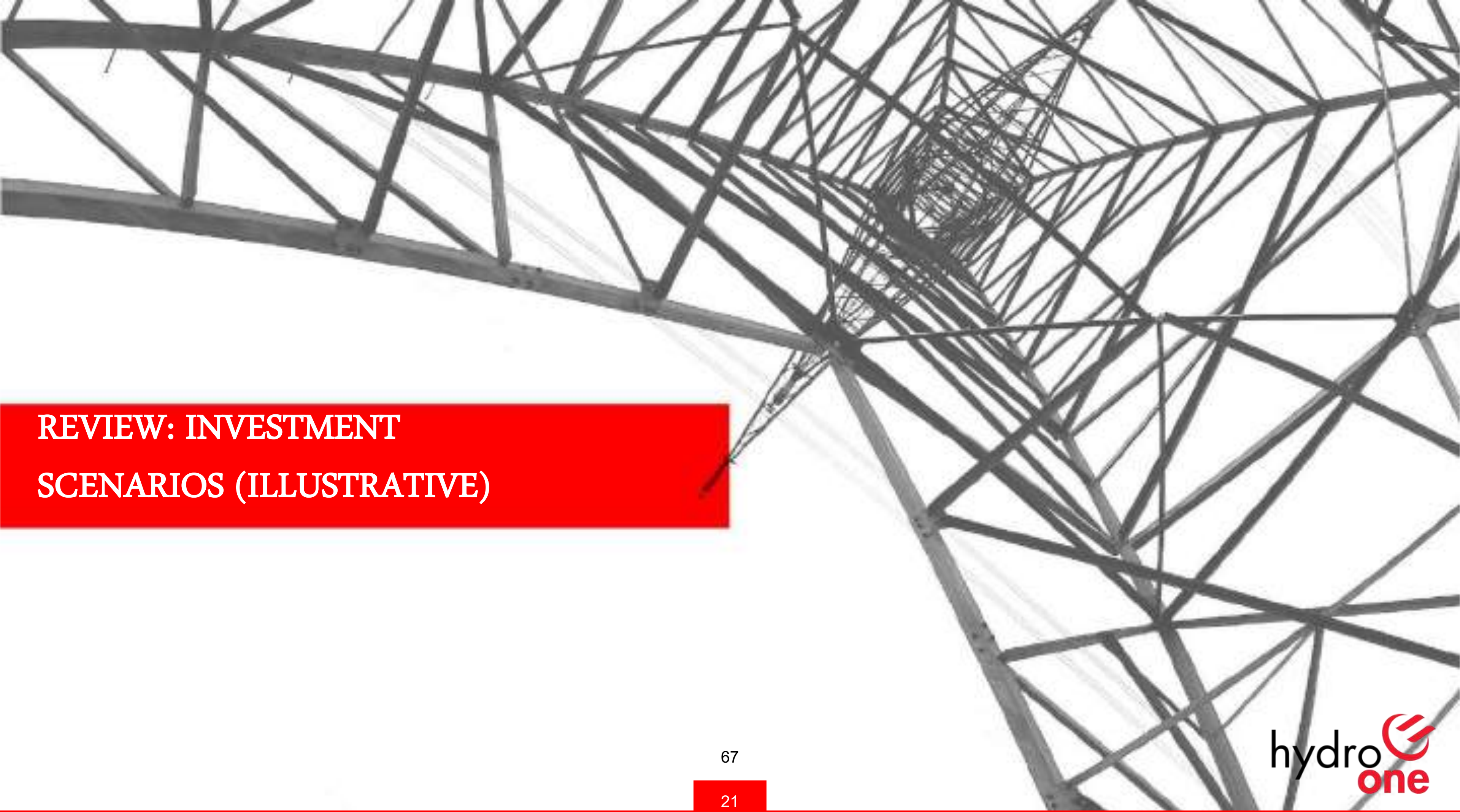
- Equipment outages[3] caused by failure or necessary repairs/replacements increased ~300% from 2011 – 2015.
- Increased duration of placing customers, normally served by a multi-circuit system[4] on single supply, increasing interruption risk by ~400%.

Condition assessments have identified critical replacement needs, for example:

- 2,300 cct-km of conductors identified for priority replacement due to being at or near end of useful life[5].
- 9,100 steel towers at heightened failure risk due to depletion of their corrosion protection layer.

Hydro One continues to take action to mitigate reliability risk by:

- Managing equipment performance through robust, condition-based asset replacement programs.
- Reducing customer exposure to single-supply through improved planning and work processes.



REVIEW: INVESTMENT SCENARIOS (ILLUSTRATIVE)

INVESTMENT SCENARIOS

Illustrative scenarios were developed for various levels of sustainment expenditures

These result in different rate impacts and reliability risks

- These illustrative scenarios focused on the Sustainment Capital portion of our Investment Plan and were meant to represent a spectrum of potential investments
- **We did not have a recommended scenario, nor did we ask customers to choose from the scenarios presented**
- The asset solutions identified are flexible. The inclusion and pacing of investments in the plan may vary from what is presented in the scenarios
- Through this conversation, we sought to better understand your business needs and preferences to inform our 5-year Investment Plan
- Hydro One presented this information in order to solicit feedback on potential alternate investment scenarios and their expected impact on the reliability of our transmission system. The scenarios were illustrative only; none of the scenarios presented were represented to be an exact scenario to be presented to the regulator. The feedback from this consultation was considered when making our regulatory filings

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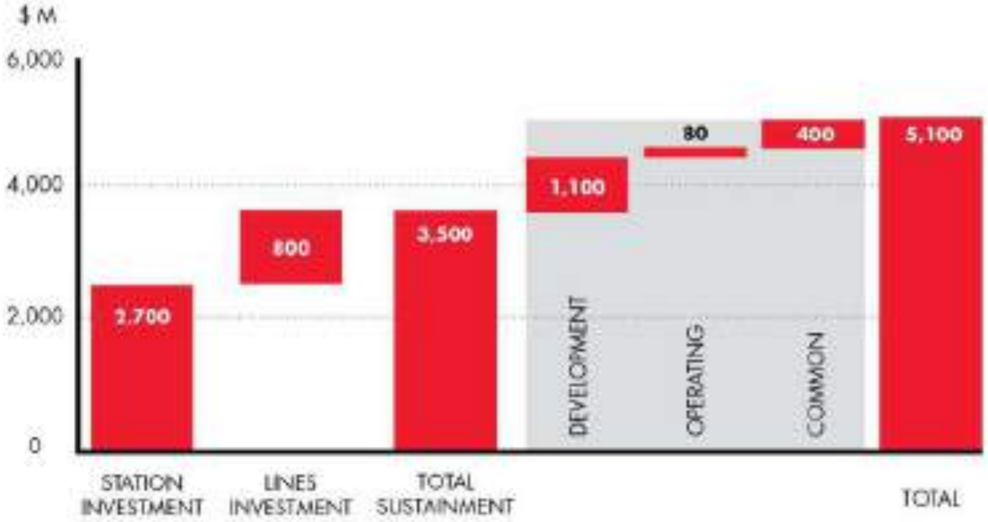
SCENARIO ONE

SCENARIO 1
~$5,100M (2016 – 2020)

KEY ELEMENTS OF SCENARIO 1

- Coordinated replacement of multiple elements at stations to reduce outages
- Investment to replace high risk air-blast circuit breakers
- Replacement of aging transformer population
- Does not fully address increasing risk due to line asset aging/conditions



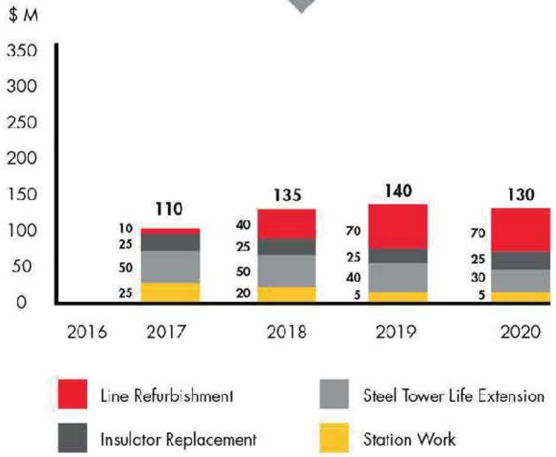
Overall risk profile:

Reliability risk expected to increase

69

SCENARIOS TWO AND THREE

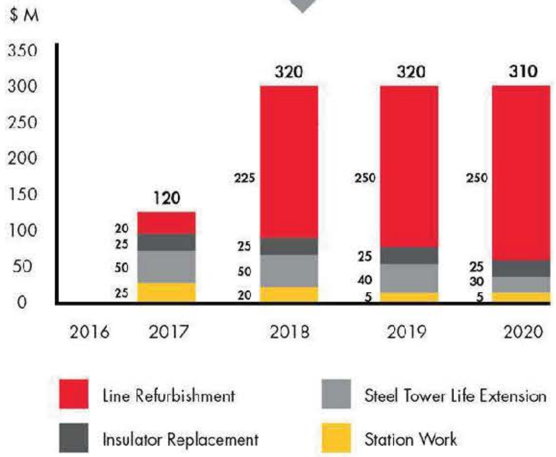
SCENARIO 2
~$520M in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 1,200 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Current reliability risk expected to remain unchanged

SCENARIO 3
~$1.1B in incremental CapEx from 2016 – 2020



- Scenario 1 and additional station work, insulator replacement, and steel tower life extension program
- Projected replacement of 2,300 cct-km of conductors, including all copper conductors at end of useful life

Overall risk profile:
Reliability risk expected to decrease

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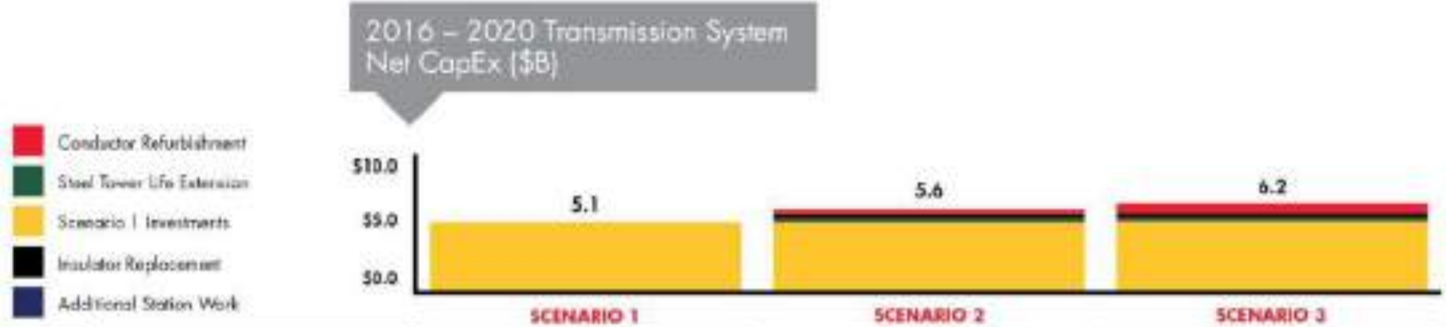
SCENARIOS BASED ON FOUR MAJOR ASSET REPLACEMENT PROGRAMS

	DESCRIPTION	RATIONALE
STATION WORK	Additional replacement of air-blast circuit breakers (ABCB) with new SF6[1] breakers	• Air-blast circuit breakers known to have 5-7x higher likelihood of unplanned outage than new SF6 breakers • ABCB is an obsolete technology and manufacturers will cease support by 2020
LINE REFURBISHMENT	Accelerated replacement of lines, based on asset condition	• 20% of conductors beyond end of service life (70 years) will reach ~40% by 2024 under historic replacement rates • Historic average replacement rate of 60 cct-km lags rate required to maintain system age • Condition assessments of conductor fleet identified 2,300 cct-km conductors are either at or near end of useful life based on actual conductor sample testing
STEEL TOWER LIFE EXTENSION	Coating of select steel tower structures to extend useful life	• 25% of towers located in high-corrosion regions • Corrosion rate for high-corrosion regions is ~10x higher than in lower corrosion regions • 20% of towers in high-corrosion regions are > 80 years old • Coating extends tower life by 25 years, deferring the need for replacement, with a net present value of $100-200M
INSULATOR REPLACEMENT	Replacement of insulators with known increased risk of failure	• Insulators installed between 1965 and 1982 have a known increased risk of failure • The insulator failure in March 2015 in the GTA reinforces the need to accelerate replacement of insulators • Condition testing underway to better quantify increased risk



		SCENARIO 1	SCENARIO 2	SCENARIO 3
Capital Spend	Sustainment ($B)	3.5	4.0	4.6
	Development ($B)	1.1	1.1	1.1
	Other ($B)	0.5	0.5	0.5
Expected Outcomes	Frequency and duration of interruptions	▲ Expected increase in line-related interruptions	► Some increase in lines risk offset by limiting unplanned outages and improved station performance	▼ Reduce risk from lines and continue to limit exposure to unplanned outages
	Reliability risk[1]	▲ Risk is expected to increase	► Current risk expected to remain essentially unchanged	▼ Risk is expected to decrease
Rates	Transmission rate impact (Compound Annual Growth Rate for 2017 – 2020)[2]	▲ ~5.8%	▲ ~6.3%	▲ ~6.8%

1. Reliability risk is a probabilistic calculation based on asset demographics and the historical relationship between its age and its failure or replacement.
2. Excludes impacts of potential changes in load forecast and any potential change to operations and maintenance spending.

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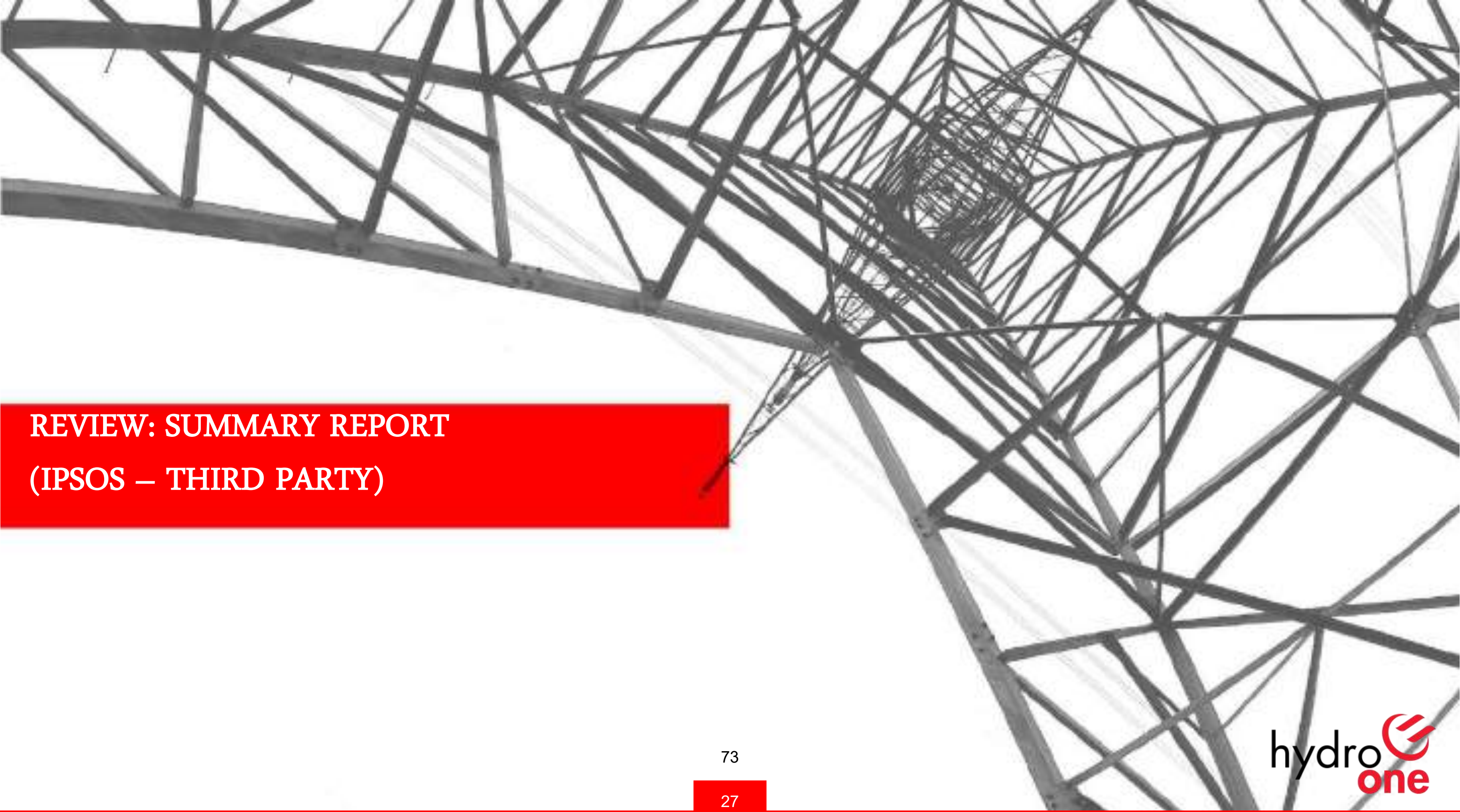


REVIEW: SUMMARY REPORT
(IPSOS – THIRD PARTY)

Summary of Process and Customer Participation

- Ipsos was engaged to ensure the methodology, the development of research and questions, and the report writing provided an unbiased, unvarnished, evidence-based consultation report
- The Ipsos Customer Consultation Report was finalized prior to the investment plan being finalized
- The approach supported collection of qualitative insight in 3 waves over the period of March to April:
    - 1st wave of 1-on-1 meetings with 12 selected customers
    - 2nd wave of five larger, facilitated group sessions
    - 3rd wave using Ipsos' online consultation tool
    - All participants were emailed an advance copy of the consultation materials

IPSOS CUSTOMER CONSULTATION REPORT (CONT'D)

Summary of Process and Customer Participation

- Wave 1 customers were among the largest customers in each segment and represented:
  - A range of customer satisfaction scores
  - A range of reliability performance
  - Geographic diversity

- All customers were invited to Wave 2 formal facilitated group sessions which were held in Ottawa, Thunder Bay, Sudbury, London and Toronto

- All customers were also invited to participate in the Wave 3 online consultation

- In total, 62 customer organizations participated which represents 34% of transmission connected customers

- The customer organizations were represented by 106 of their staff

Summary of Customer Needs and Preferences

Reliability was the most frequently and consistently mentioned need

- Industrial customers focused on frequency
- LDCs were more concerned with duration
- Improvement in both are among the top needs for all customers
- Planned outages are less of a concern than unplanned interruptions

All customers desire good reliability at a competitive or low cost

Interruptions and rates (specifically increases > 5%) were mentioned as the top 2 concerns

IPSOS CUSTOMER CONSULTATION REPORT (CONT'D)

Summary of Customer Needs and Preferences (Cont'd)

- Most customers believe Hydro One needs to be more proactive in addressing current and emerging reliability risk
- Majority of customers indicated increased reliability risk is unacceptable
- Most customers support investment required to at least maintain the current level of reliability
- General sentiment was that the right balance between reliability risk and rates is somewhere between Illustrative Scenario 2 and Scenario 3
- Positive feedback about the consultation process and had a high level of interest in learning more about Hydro One's system performance, asset age, condition assessments and plans to mitigate reliability risk

DISCUSSION: SUBMITTED PLAN
(I.E. RATE IMPACTS)

HYDRO ONE'S BUSINESS PLAN SUBMISSION FOR 2017 / 2018 RATE FILING

Business Plan Submitted:

Final Plan – Sustainment investment spend is between Illustrative Scenario 2 and 3, based on Customer feedback and reliability risk considerations. The key changes from previous plan / proposal that impact reliability risk are:

Station Sustainment

Small decrease in funding levels, based on re-prioritization review

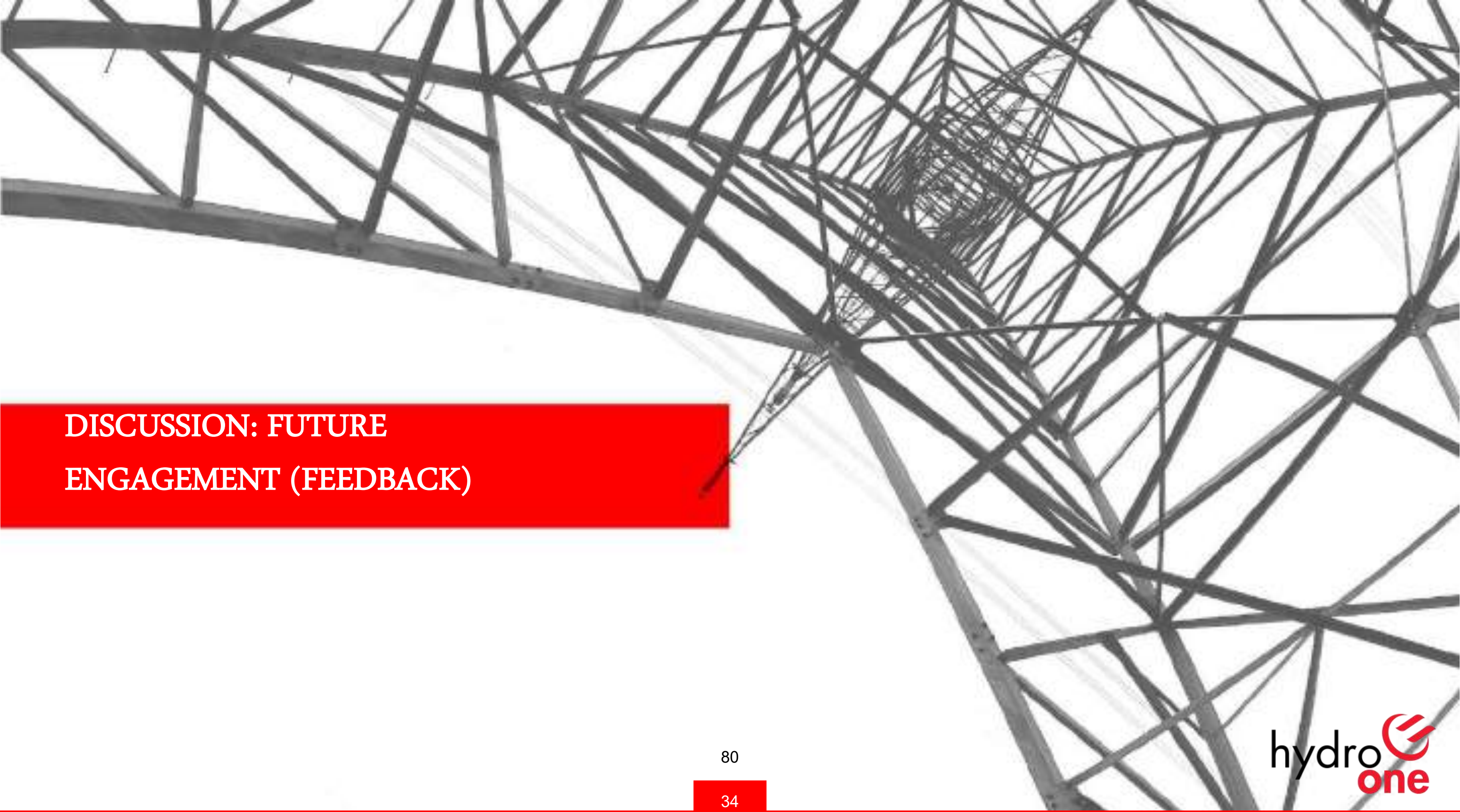
Lines Sustainment

Increase in funding levels to above historical annual levels, to align with desired reliability risk profile outcomes

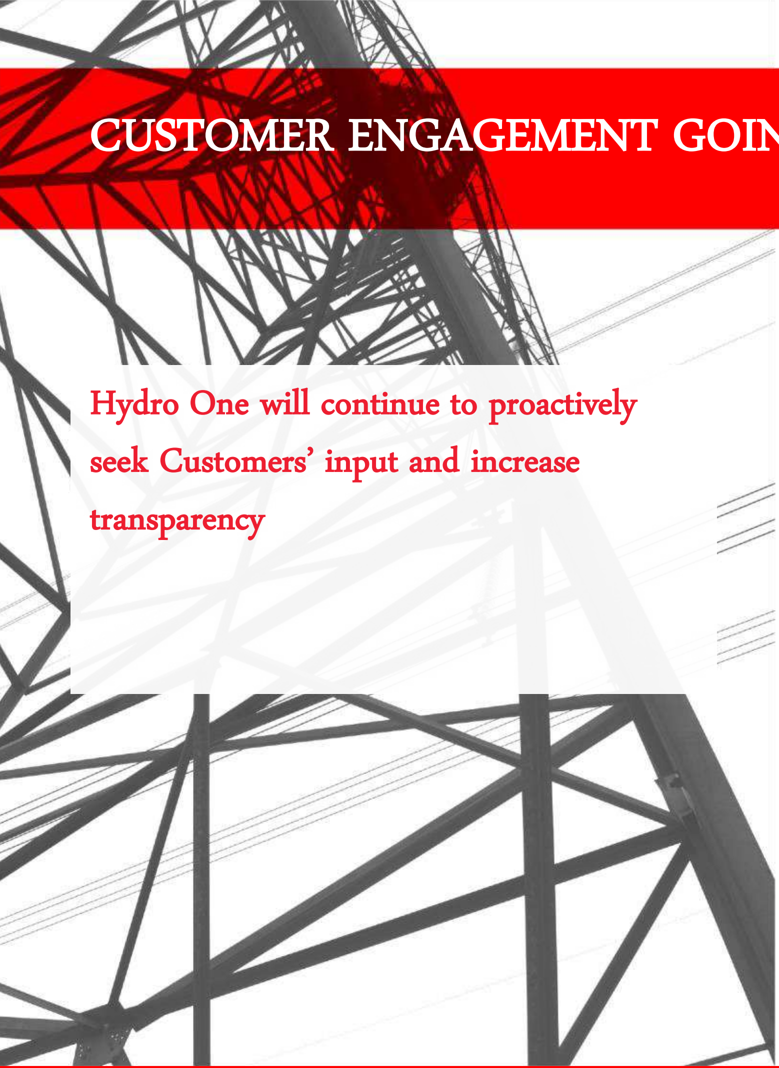
- Insulators Replacements
- Conductor Replacements
- Steel Tower Coating

Anticipated Rates Impact (if OEB approved as submitted)

Transmission portion of the bill: 2017 = 4.2%, 2018 = 5.2%



DISCUSSION: FUTURE ENGAGEMENT (FEEDBACK)



CUSTOMER ENGAGEMENT GOING FORWARD

Hydro One will continue to proactively seek Customers' input and increase transparency

All of the existing interactions and touch points between Hydro One and our transmission customers will continue:

- Connection and sustainment projects
- Outage planning
- Real time operating events & follow-up
- Regional system planning
- Customer conference

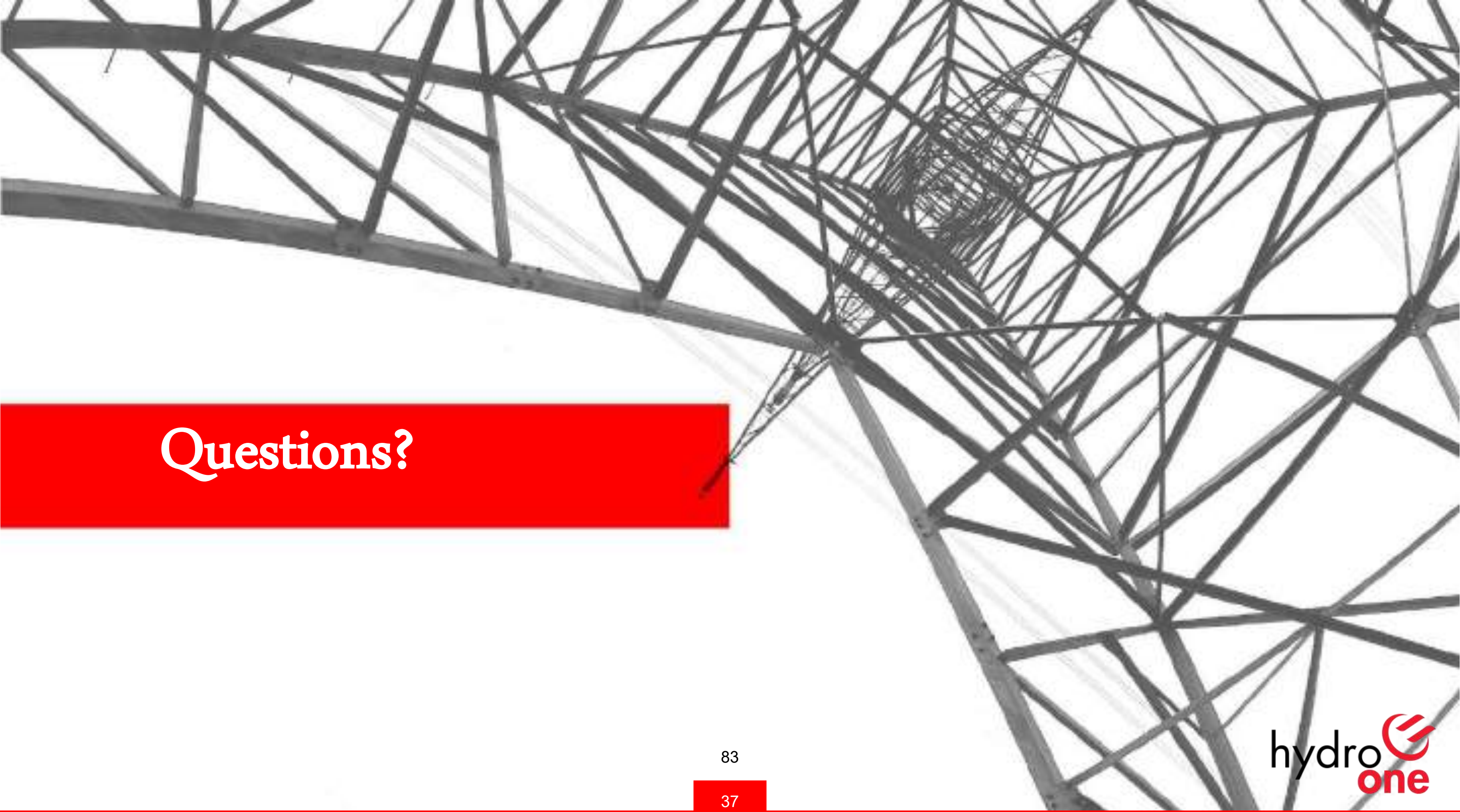
Hydro One is also focused on enhancing our proactive communications to you:

- More robust and comprehensive Reliability Reports
- Customer Delivery Point Performance Standards Reports
- Information regarding major sustainment projects
- More granular reliability statistics and information
- Large customer web portal in 2017

CUSTOMER ENGAGEMENT GOING FORWARD (CONT'D)

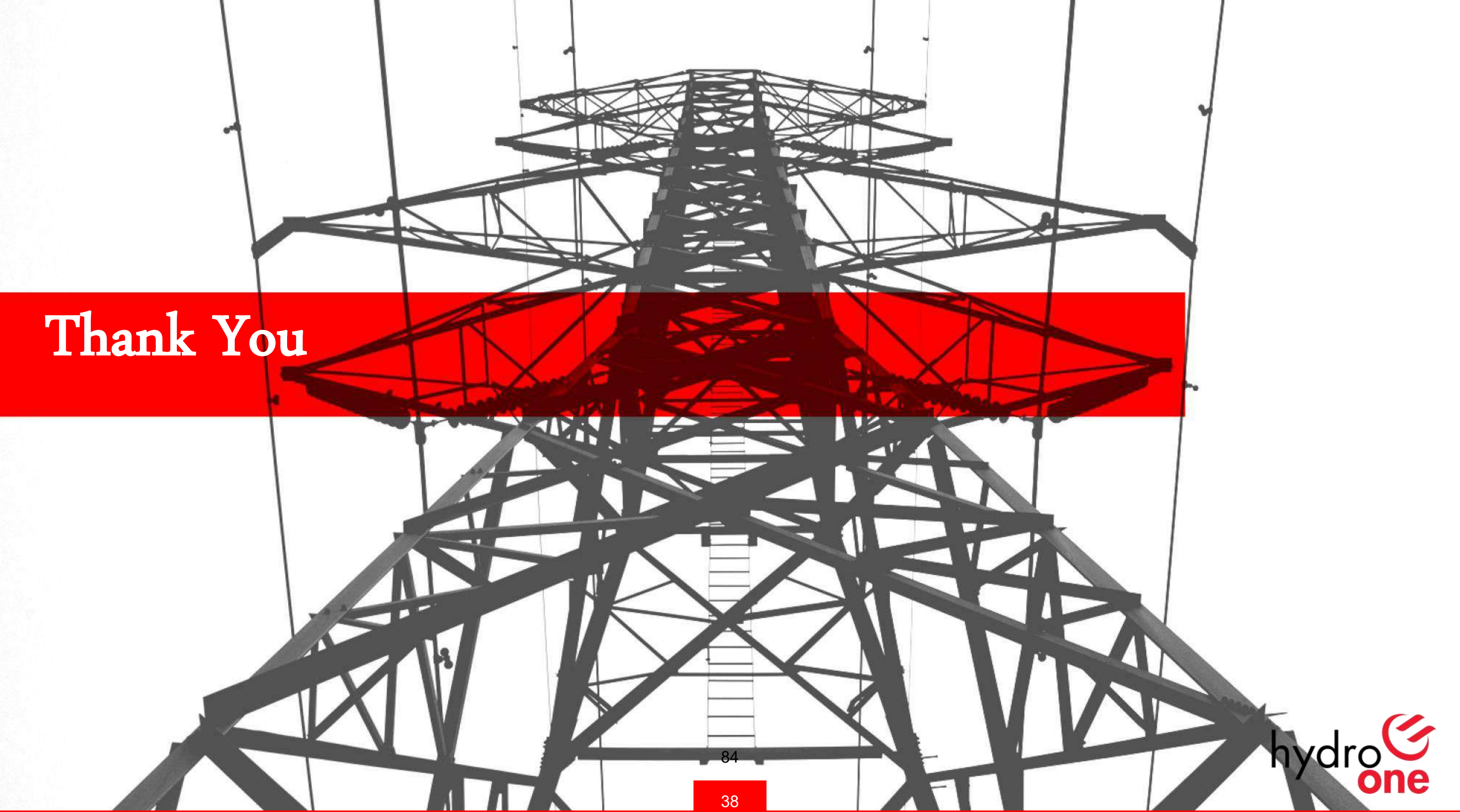
Hydro One will continue to proactively seek Customers' input and increase transparency

- The customer input received this year regarding your needs and preferences with respect to the development of Hydro One's investment plan was very valuable
- Hydro One is committed to continue a formal exercise to provide information and seek Customer's input as future investment plans are developed
- The methodology used may be different.
- We welcome your suggestions to ensure such exercises are inclusive and effective

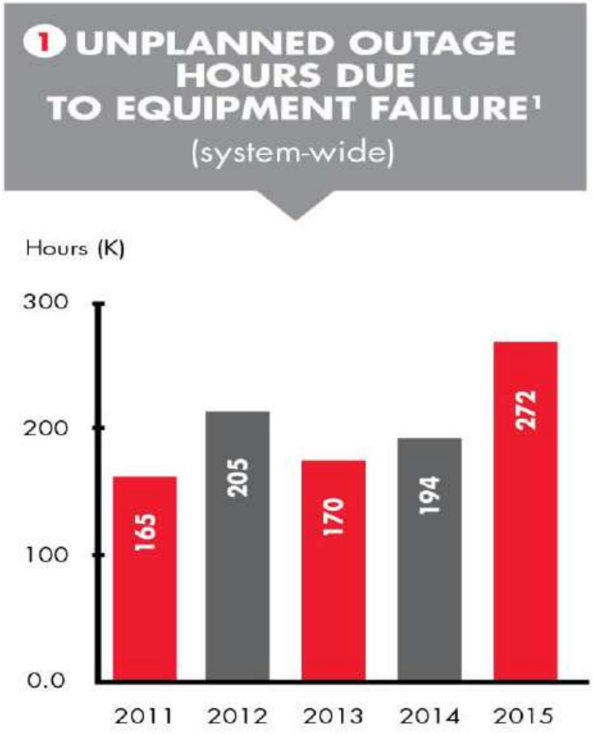


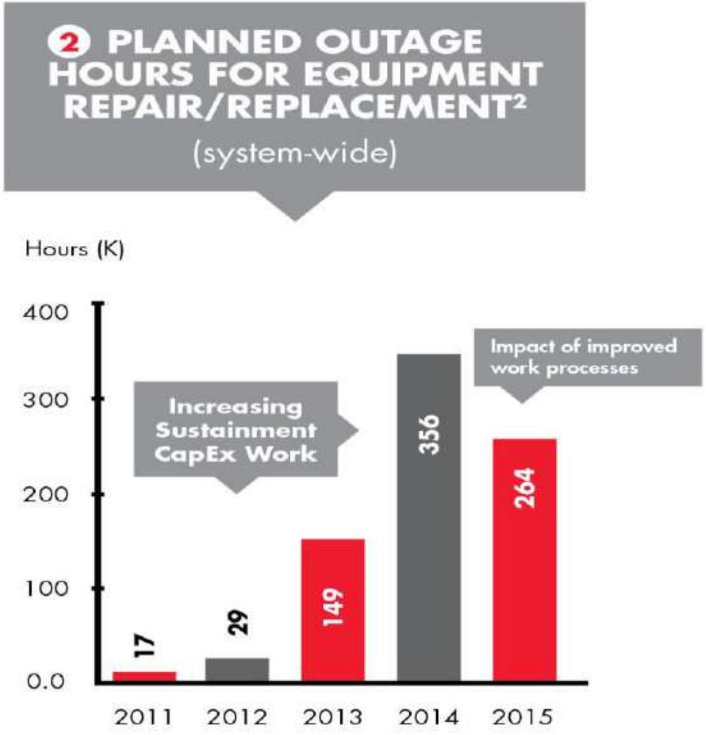
Questions?

Thank You



ASSET CONDITION IS INCREASING OUTAGES ACROSS THE SYSTEM





Implications of outages:

Single-circuit system: Increased duration of interruptions

Multi-circuit system:

Greater time on single supply → increased interruption risk

1. Includes direct outages caused by power equipment or protection equipment failure
2. Includes total duration of planned outages designated as for repair or replacement across all equipment types

Ontario Planning Outlook

Presentation to Hydro One
Large Customer Conference
Productivity & Operational Efficiency

Michael Lyle

Vice President, Planning, Legal, Indigenous Relations and Regulatory Affairs

November 21, 2016

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Planning Context Under Bill 135

Bill 135, the *Energy Statute Law Amendment Act, 2016*

Received Royal Assent on June 09, 2016

IESO Technical Report, "Ontario Planning Outlook"

↓

Ontario Government's Long-Term Energy Plan (LTEP)

↓

IESO Implementation Plan

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IESO's Ontario Planning Outlook

- The Ontario Planning Outlook is a technical report that provides a 10-year review (2005-2015) and a 20-year outlook (2016-2035) for Ontario's electricity system
- The report responds to a June 10, 2016, request from the Minister of Energy to have the IESO submit a technical report on the adequacy and reliability of Ontario's electricity resources
- The report will serve as an objective baseline for the Ministry of Energy and sector stakeholders in terms of electricity demand and supply outlooks, and will inform the Ministry's formal consultation process for the development of the LTEP

The report can be found on the main page of the IESO's website @ ieso.ca

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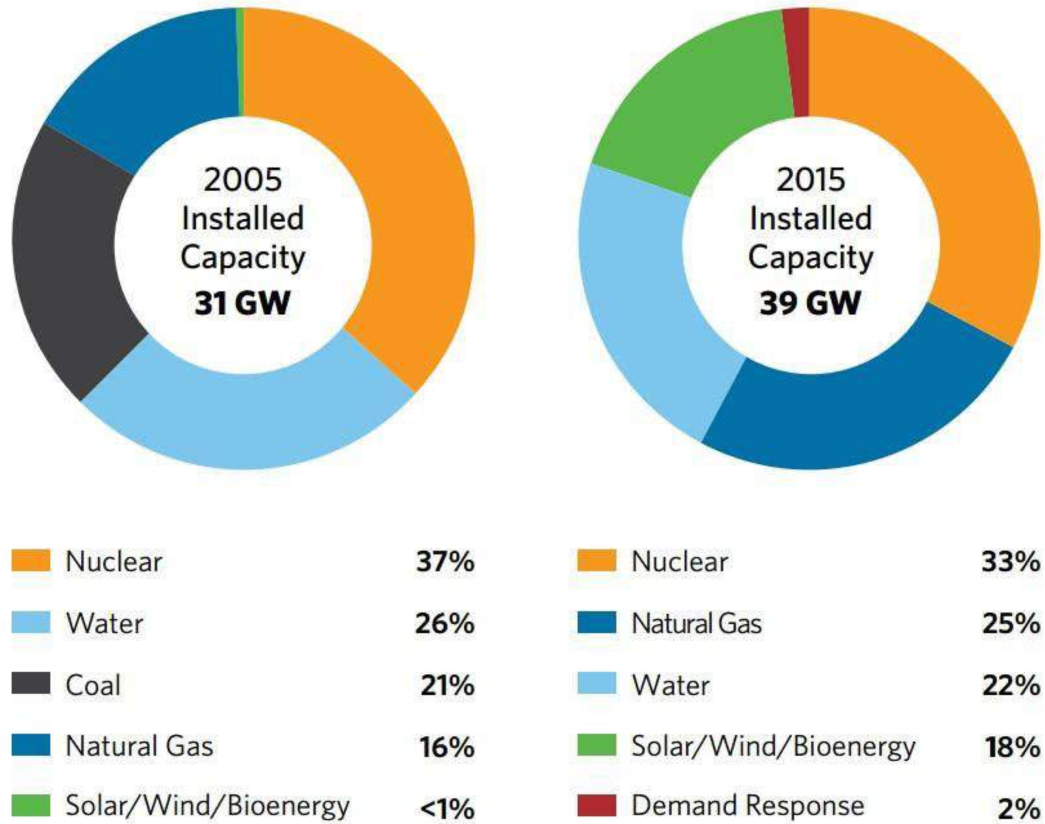
State of the System > 10-Year Review

Changes over the last decade have:

- Have addressed the reliability concerns of a decade ago
- Coal-fired generation has been retired and at the same time Ontario saw additions in non-carbon emitting and natural gas-fired generation
- Reduced greenhouse gas emissions in Ontario's electricity sector by more than 80 percent
- With current planned investments, will meet the province's electricity needs well into the next decade



20-Year Outlook

- The IESO has considered a range for electricity demand in Ontario, reflected in four outlooks that provide context for long-term integrated planning and discussion
- The outlooks all reflect the actions identified in the government's recently announced Climate Change Action Plan

Four Outlooks

Outlook A (or low demand outlook), which explores the implications of lower electricity demand

Outlook B (or flat demand outlook), which explores a level of long-term demand that roughly matches the level of demand that exists today

Outlooks C and D (or higher demand outlooks), which explore higher levels of demand driven by different levels of electrification associated with policy choices on climate change

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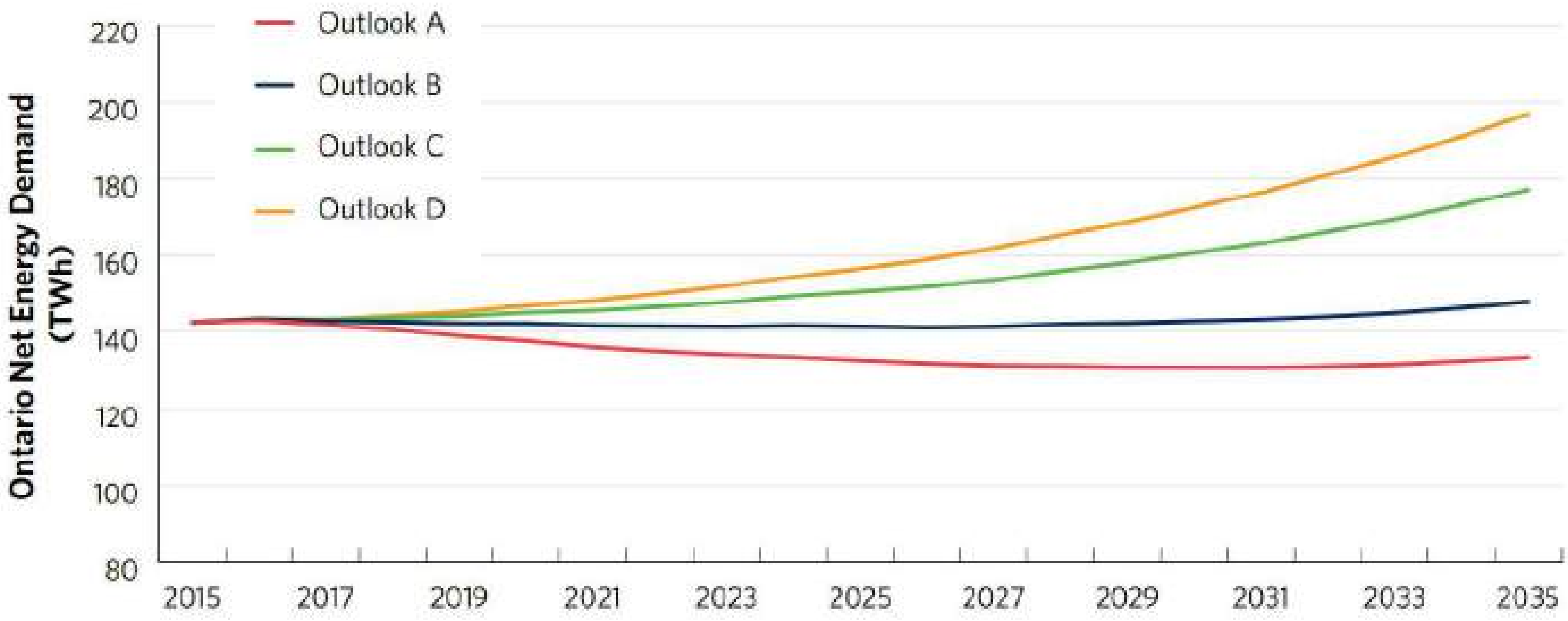
Four Demand Outlooks



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Demand Outlooks > Cont'd

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64 TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

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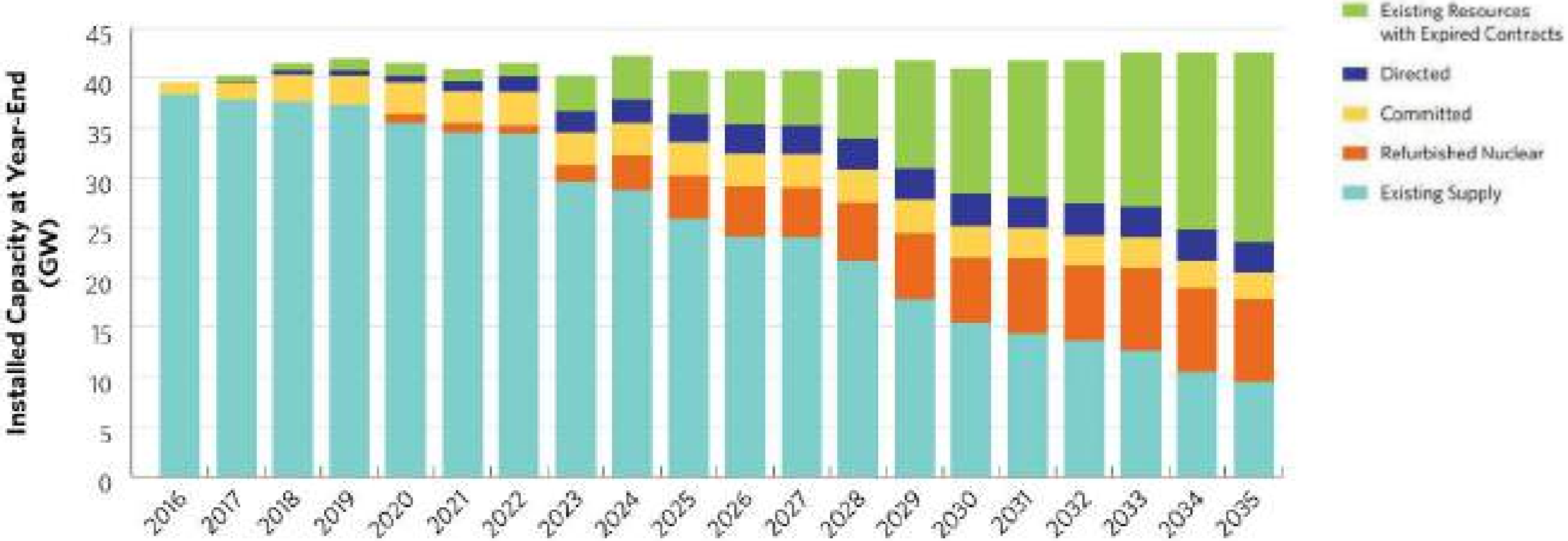
Supply Outlook

Ontario is in a strong starting position to reliably address the range of demand outlooks

- If all existing resources continue to operate after contract expiry and if planned resources come into service as scheduled, Ontario would have a total installed capacity of **~43 GW by 2035**
- In contrast, if all existing resources are removed from service after contract expiry, Ontario would have a total installed capacity of **~25 GW by 2035**
- Potential implementation delays, including with the nuclear refurbishment program, and the effect of aging on the performance of the generation fleet could affect the availability of supply over the planning outlook



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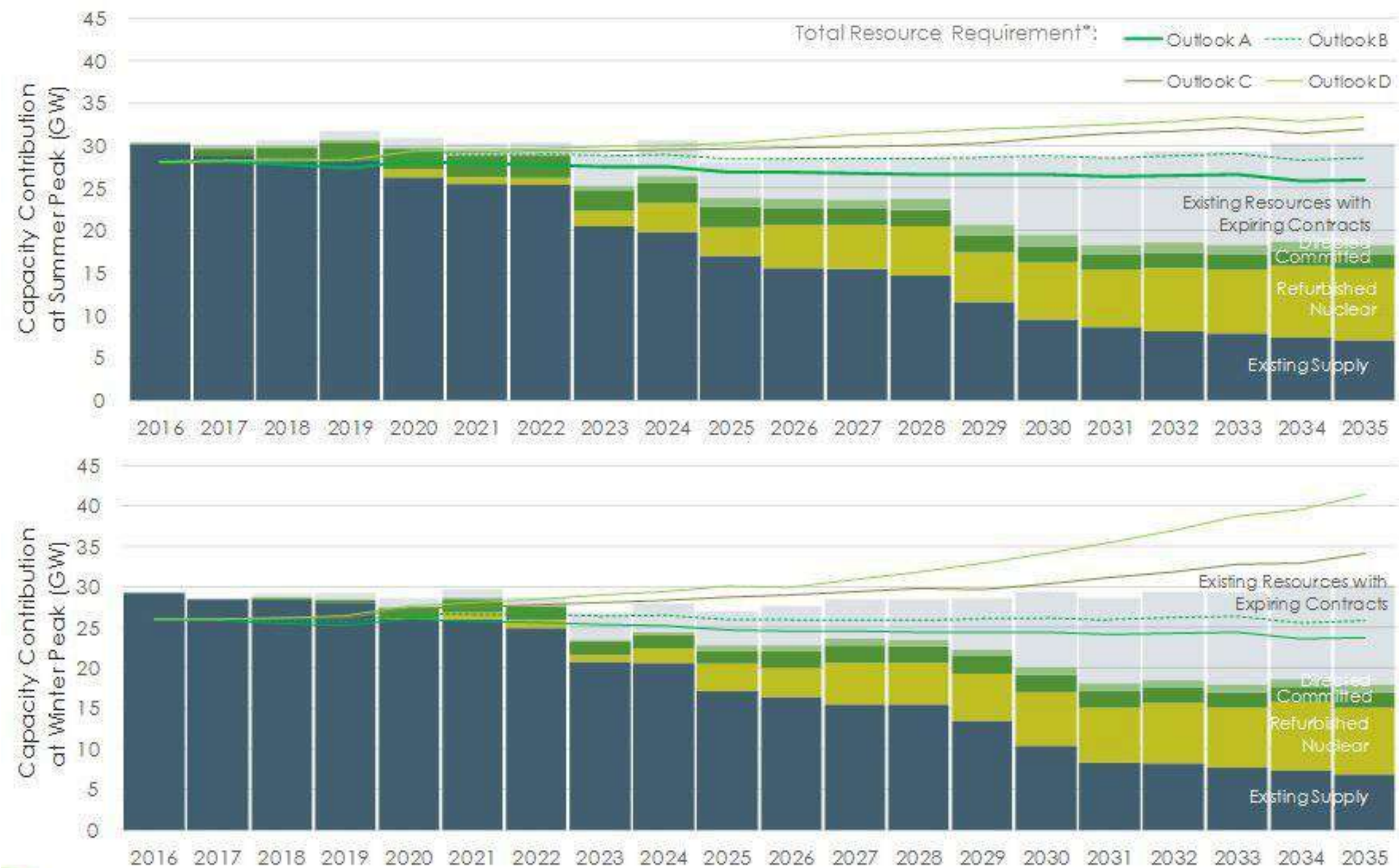
Resource Adequacy Outlook

- Ontario's existing, committed and directed resources would be sufficient, at the provincial level, to meet the flat demand outlook

- There is enough flexibility to address a lower growth in demand or to adapt to new opportunities or priorities

- Additional resources would be required to meet any increased growth in demand



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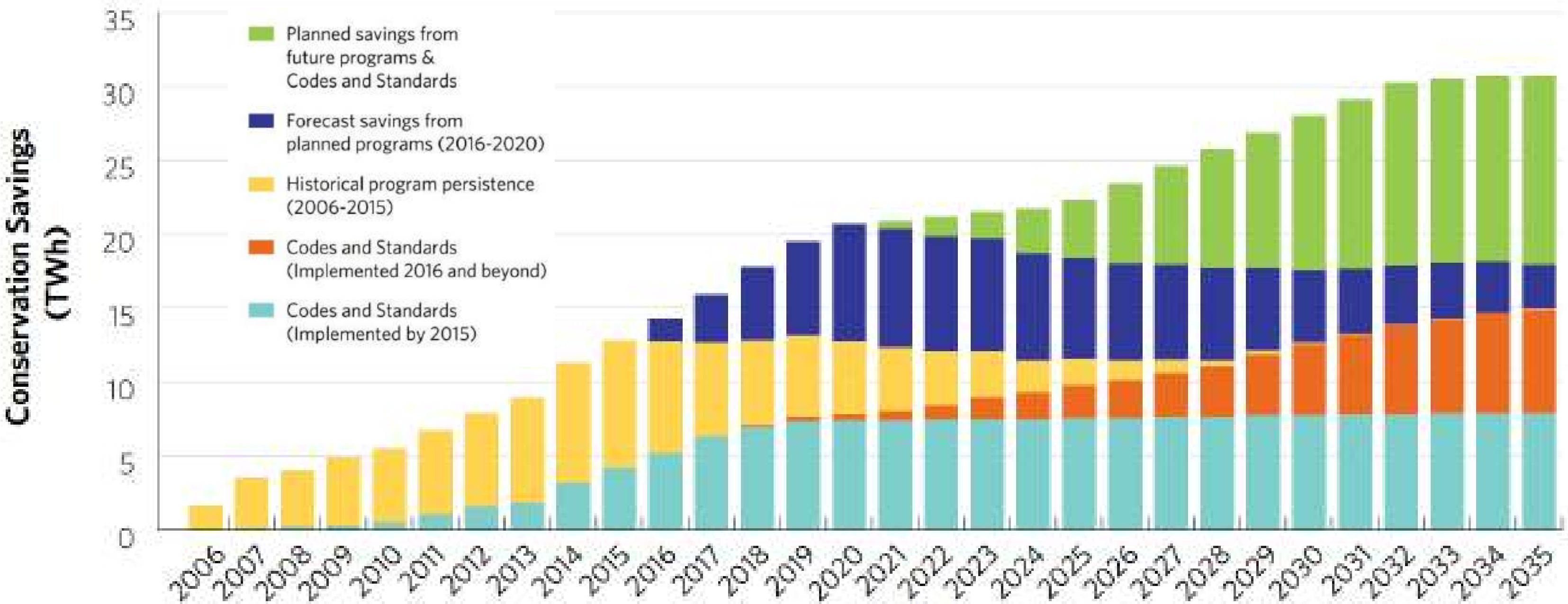
Conservation Outlook

All four outlooks reflect achievement of LTEP 2013 conservation targets and the Conservation First Framework



- Targets will be achieved through a combination of conservation programs and building codes and equipment standards addressing current electricity end uses
- Half the target is expected to be achieved through existing and planned programs and codes/standards. Remaining would be achieved through new programs and/or new codes/standards yet to be developed.
- In the flat demand outlook, conservation effectively offsets all growth due to economic activity

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Distributed Energy Resources > Key Considerations

- Evolutions in technology and policy are expanding opportunities for customer engagement and participation

- Distributed energy resources (DERs) are contributing to a system more characterized by two-way flows, rather than only one-way delivery from large central stations

- A number of communities are now developing community energy plans and DER is becoming a key component of those plans

- Higher growth outlooks provide greater opportunities for harnessing DER and reducing the need for new grid-connected resources

- Addressing barriers to the adoption of distributed energy resources, such as cost allocation and integration issues, could help to better realize their potential benefits

Transmission and distribution outlook

- Beyond current projects, no significant new transmission investments would be required in the flat electricity demand outlook served by existing and currently planned resources.

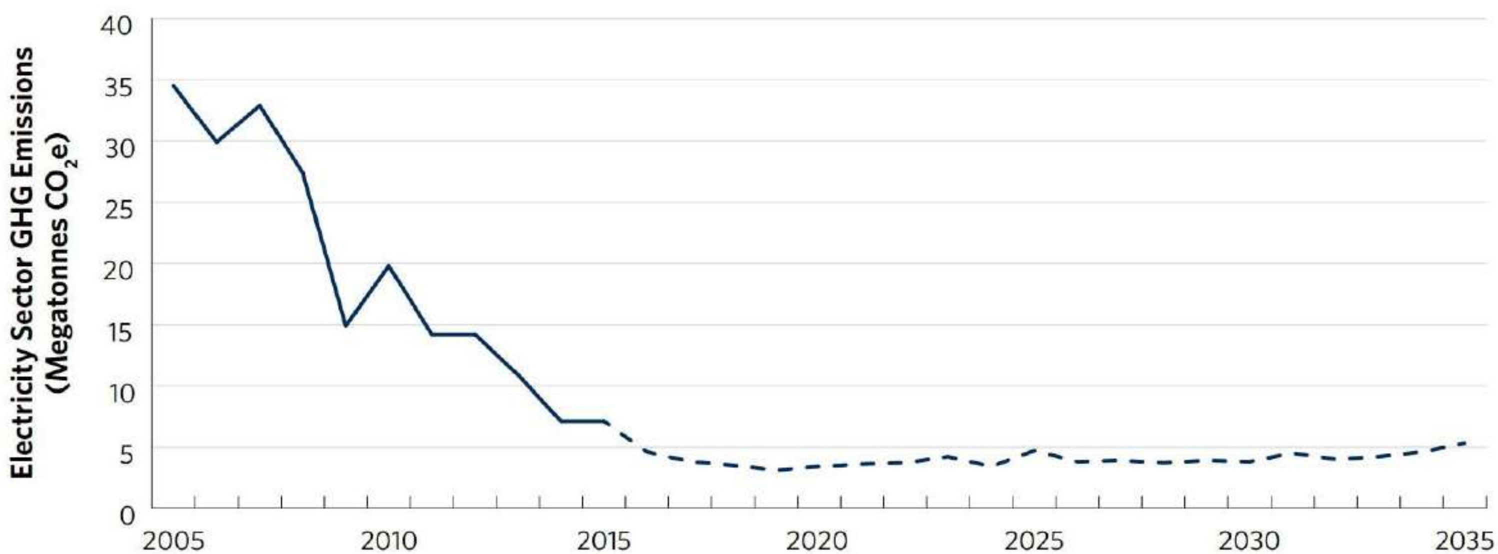
- However the amount of remaining transmission availability is limited - in higher demand outlooks, long lead-time investments in transmission will be required to accommodate new resources.

- In the near term, while the system could manage some overall increases in demand, LDCs and regional transmission may be more significantly impacted as local peak demands grow.
  - Strategies and options to address local issues could be addressed in regional planning processes, working together with transmitters and LDCs

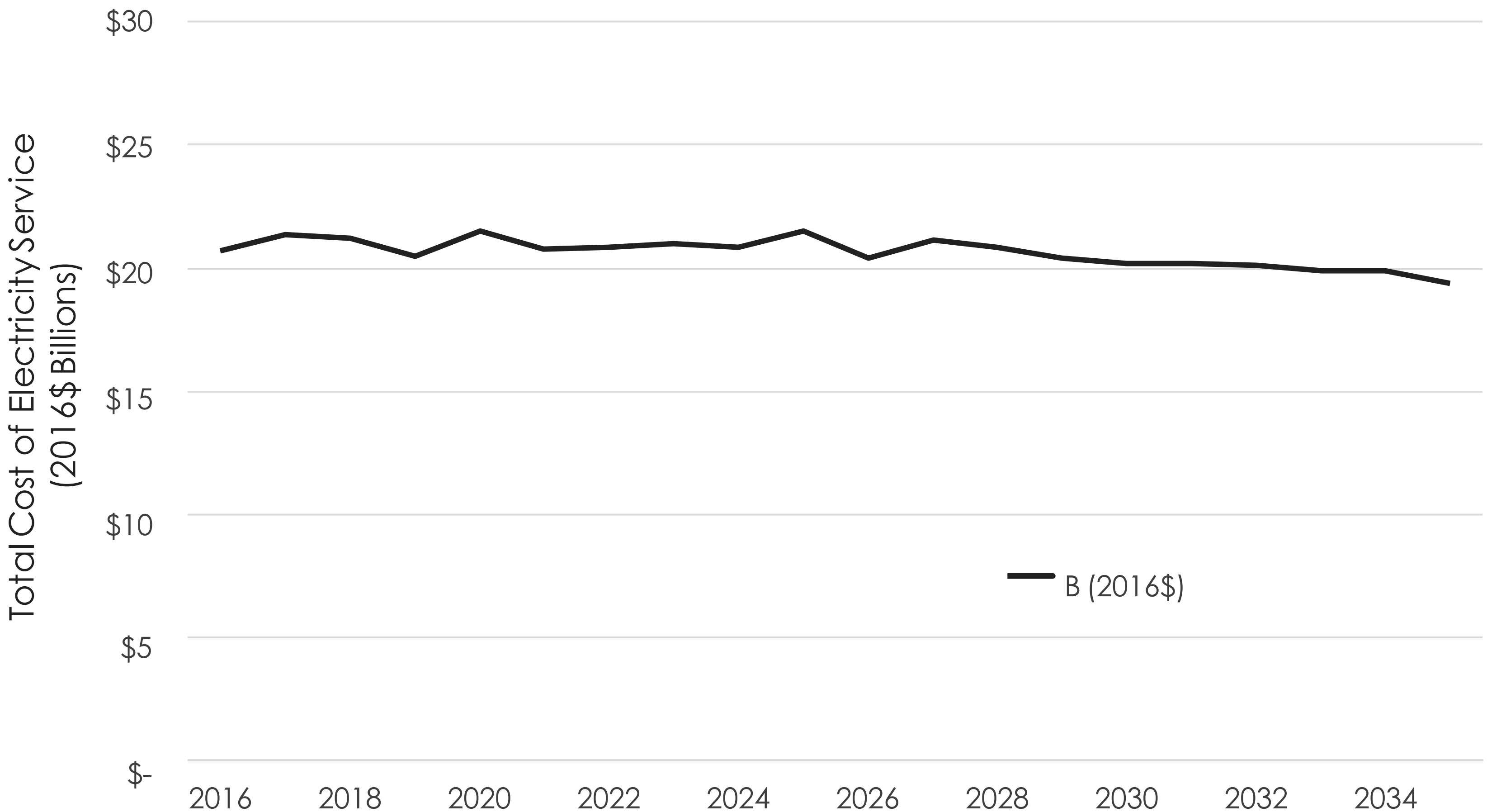
Emissions Outlook

- Emissions are expected to continue to decline over the next five years
- With Cap and Trade takes effect in 2017, emissions will be lower than what they otherwise would have been
- In the flat demand outlook, emissions rise slightly following Pickering retirement but remain well below historical levels and relatively flat through to 2035
- Consideration of how to address the higher demand outlooks was based on keeping GHG emissions in the electricity sector within the range of the flat demand outlook

Figure 18: Electricity Sector GHG Emissions in Outlook B



Total Cost of Electricity Service: Outlook B



Electricity System Cost Outlook

- In the flat demand outlook, total cost averages ~$21B/year over the next decade and is estimated to decrease to about $19B by 2035 (2016$)

- In higher demand outlooks, investments in new resources (conservation, generation, and transmission) would be required to meet the increase in demand and to reduce increases in emissions
  - Annual cost of electricity service would rise by $4B to $9B by 2035 (2016$)
  - This would be associated with an increase in energy consumption in the province
  - As a result, the average unit cost of electricity service would be within the range of the flat demand outlook

Conclusion

- Electrification of the economy in support of climate change actions could see long-term provincial electricity demands that are up to 40% higher than today. Meeting this scale of electricity demand growth would require the coordinated deployment of multiple low carbon options.
- The scale, cost and practical challenge of implementing options to meet higher demands further highlights the importance of conservation as a method of moderating electricity demand growth.
- In brief, Ontario has access to options for meeting electrification-driven demand growth in ways that result in significant economy-wide carbon emission reductions. In addressing the associated planning issues, the IESO is committed to supporting the Ministry's consultations as the new LTEP is developed.

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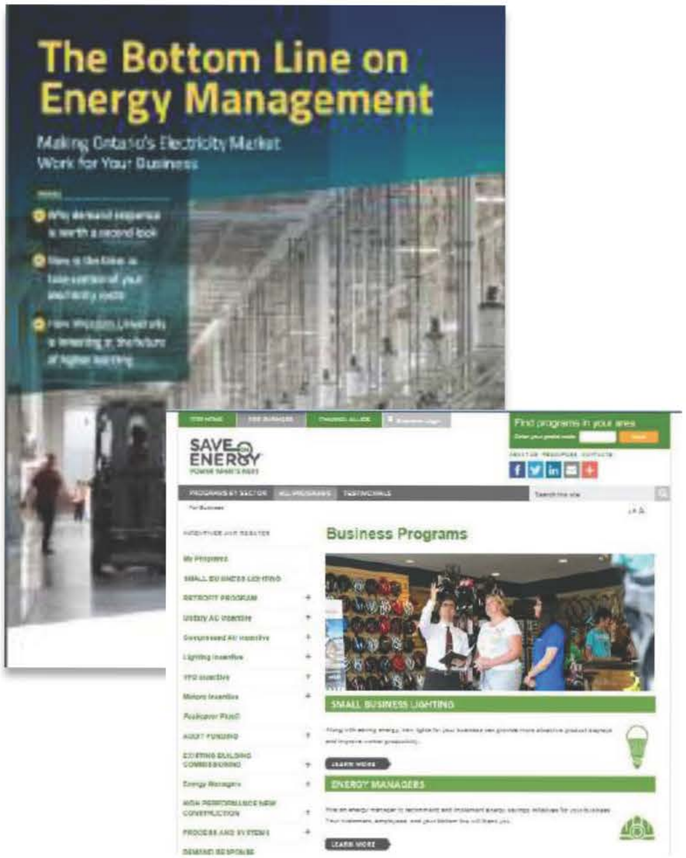
IESO Resources – *Keep in Touch*



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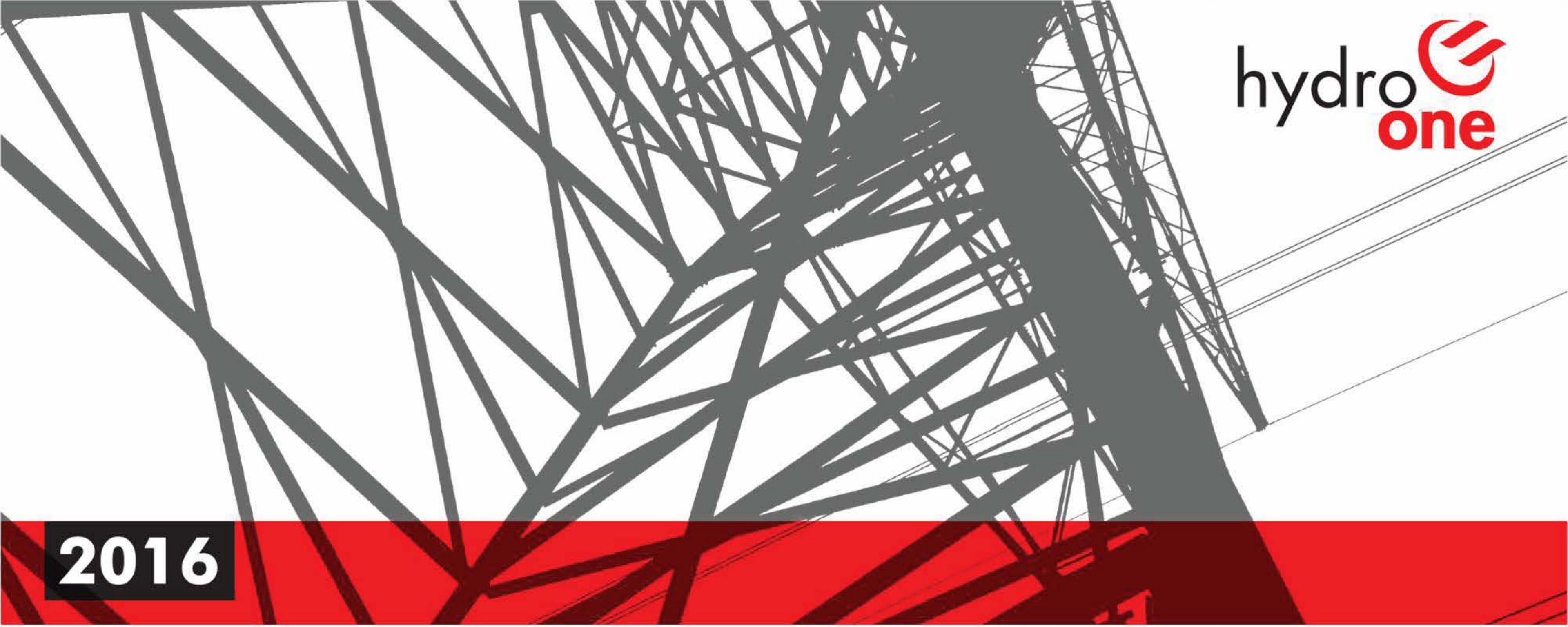
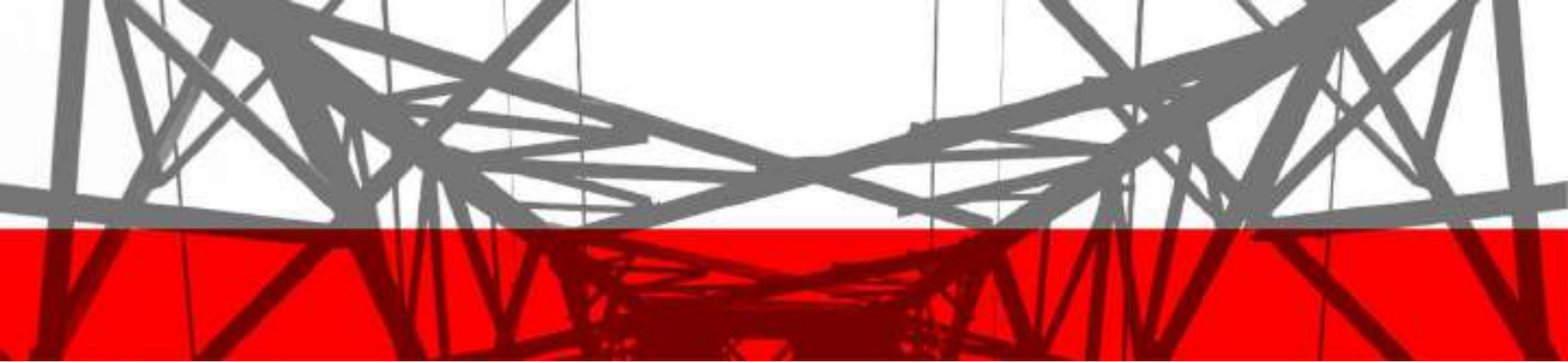


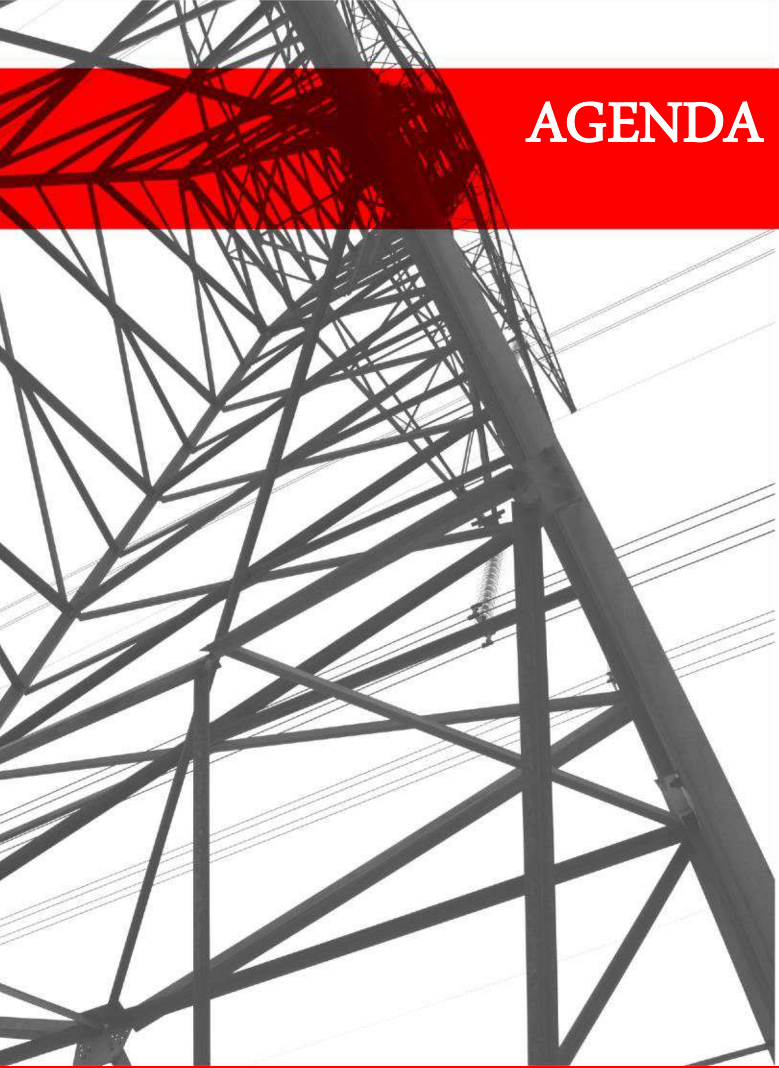
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



VOICE OF THE CUSTOMER

2016 Large Customer Conference



AGENDA

1. Purpose of today's session
2. Our commitment to large customers
3. What we've heard from you
4. What we've done to meet your needs
5. Now, it's your turn
6. It doesn't end today

VOICE OF THE CUSTOMER

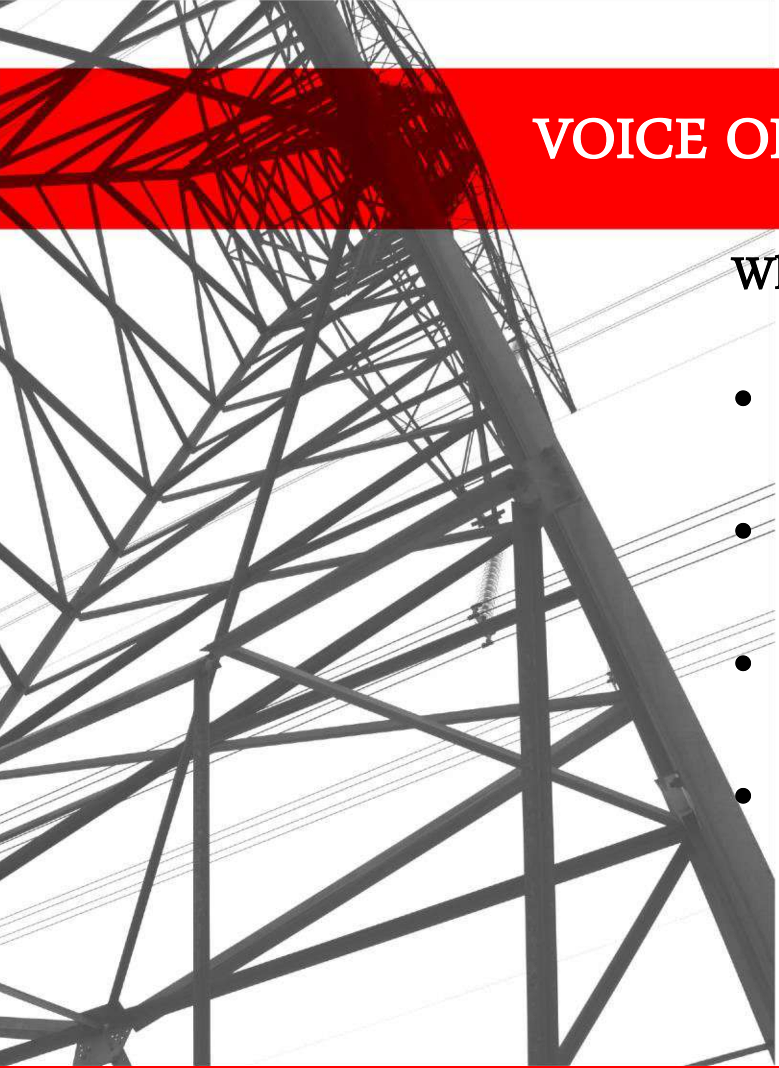
Purpose of today's session

- Listen to your concerns and better understand your needs
- Identify any opportunities to add value to your business
- Capture your feedback and ensure follow-up by your Account Executive

VOICE OF THE CUSTOMER

Our commitment to large customers

- Large customers are a major driver of our success
- We are fully committed to continuous improvement



VOICE OF THE CUSTOMER

What we've heard from you last year

- Customer service, response timeliness
- Communications
- Equipment failures
- Power Quality and reliability

VOICE OF THE CUSTOMER

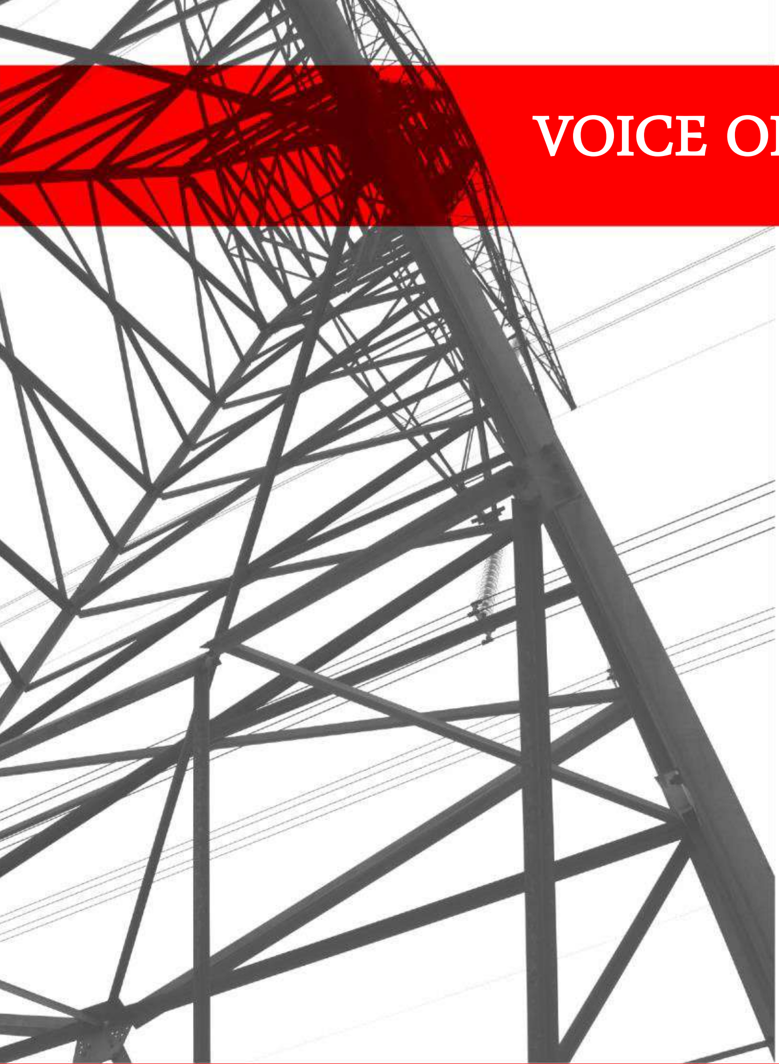
What we've done to meet your needs

- Drive process, reporting and communication improvements to identify and respond to your needs
    - Tx Customer Consultation sessions
    - Working groups, Reliability Reports and Customer Delivery Point Performance Standard

VOICE OF THE CUSTOMER

Now it's your turn

- Raise your hand so we can see you
- Please introduce yourself by stating your name and organization

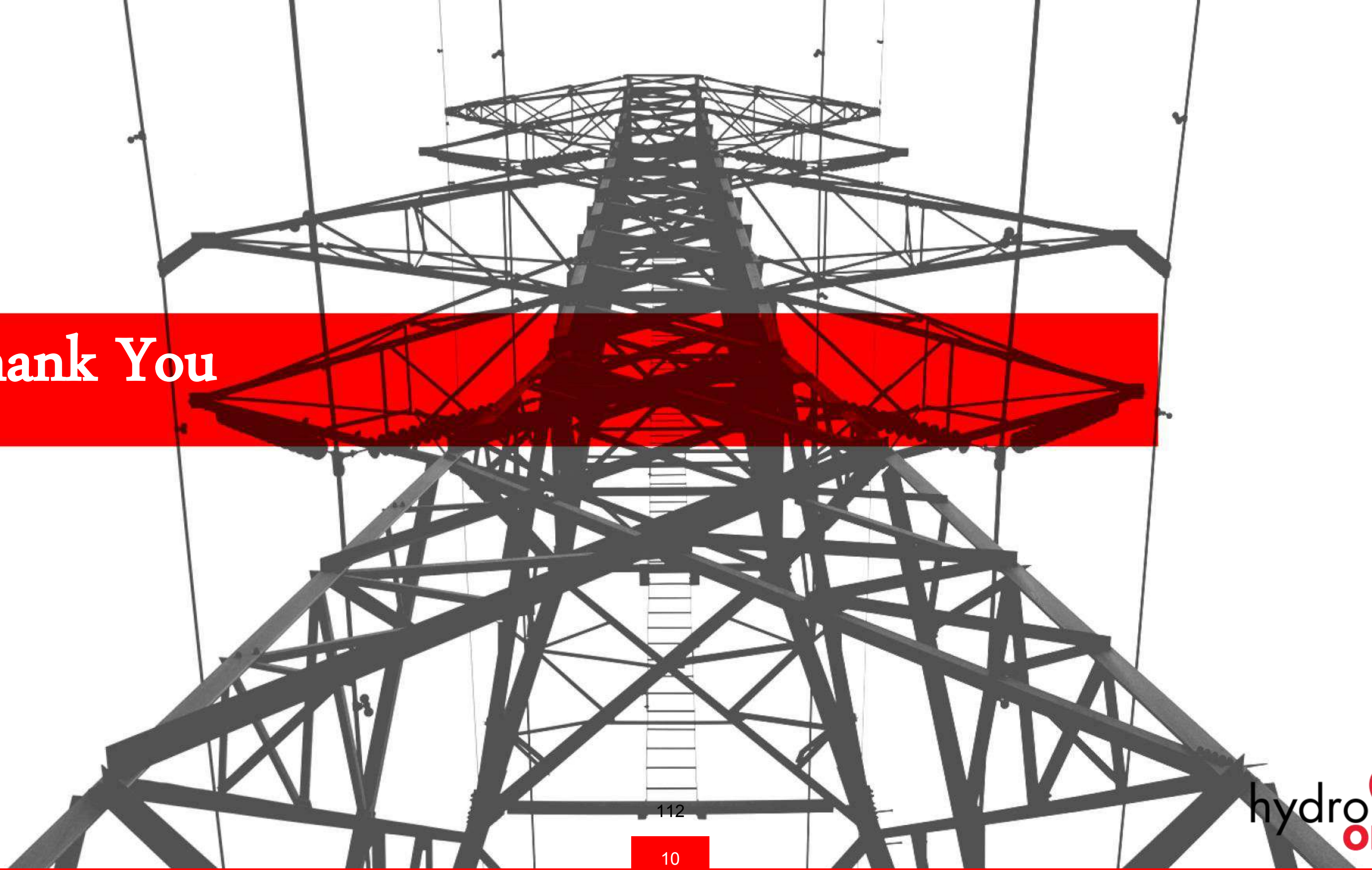


VOICE OF THE CUSTOMER

It doesn’t end today

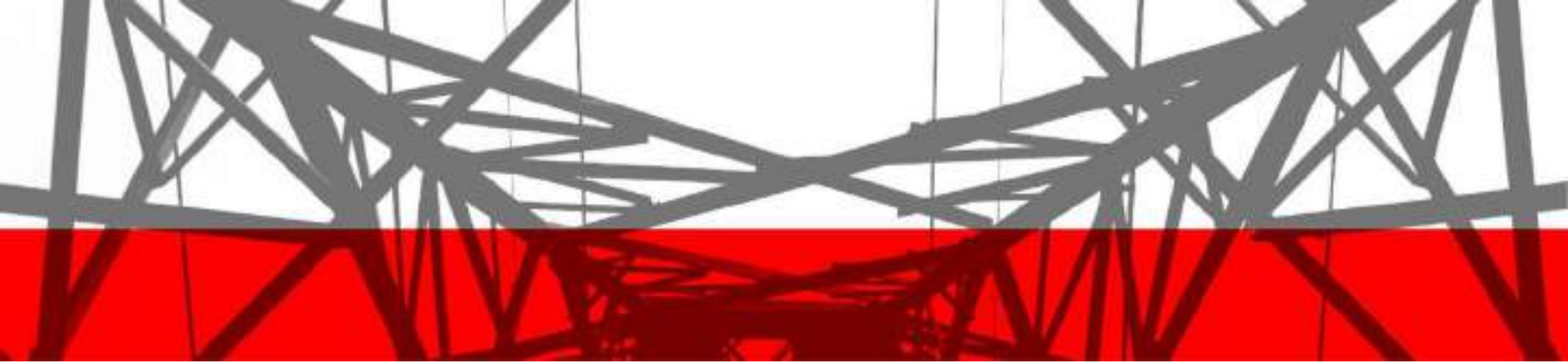
- Your Account Executive, Executive Sponsor and/or other staff will follow-up with you directly

Thank You



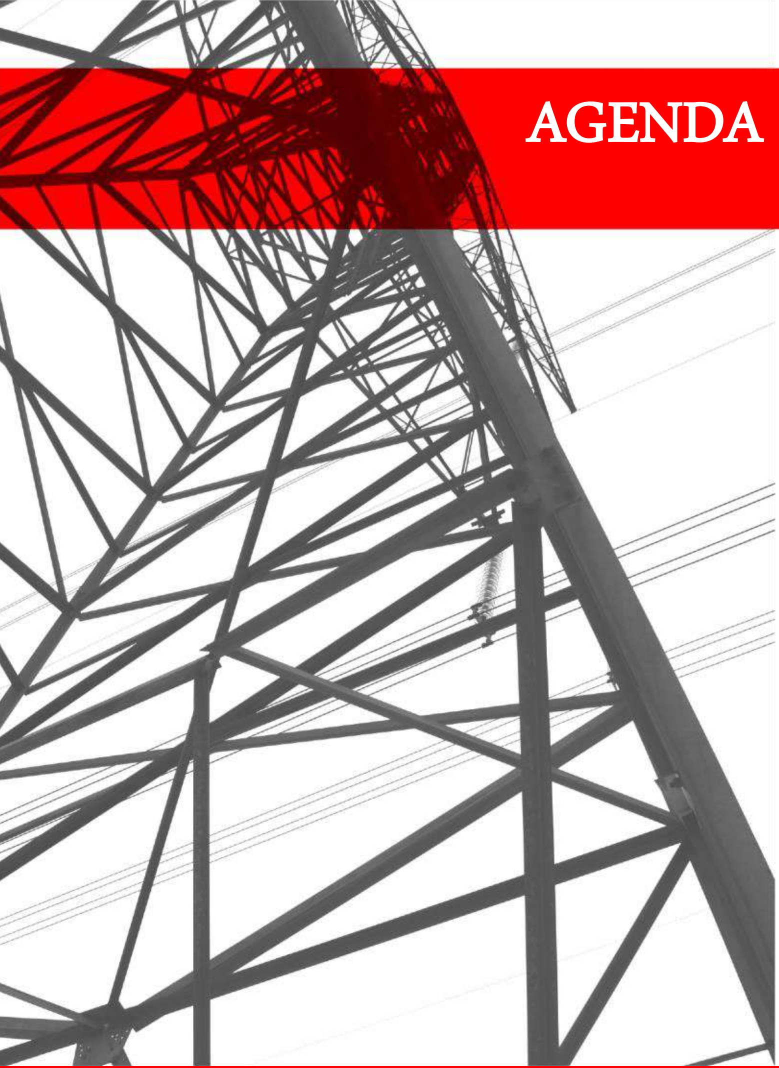
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



VOICE OF THE CUSTOMER

2016 Large Customer Conference



AGENDA

1. Purpose of today's session
2. Our commitment to large customers
3. What we've heard from you
4. What we've done to meet your needs
5. Now, it's your turn
6. It doesn't end today

VOICE OF THE CUSTOMER

Purpose of today's session

- Listen to your concerns and better understand your needs
- Identify any opportunities to add value to your business
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VOICE OF THE CUSTOMER

Our commitment to large customers

- Large customers are a major driver of our success
- We are fully committed to continuous improvement

VOICE OF THE CUSTOMER

What we've heard from you last year

- Minimize planned outages
- Outage communications, work bundling and restoration timelines
- More detail around costs

VOICE OF THE CUSTOMER

What we've done to meet your needs

- Drive process, reporting and communication improvements to identify and respond to your needs
  - Minimizing number of planned outages
  - Tx Customer Consultation sessions

VOICE OF THE CUSTOMER

Now it's your turn

- Raise your hand so we can see you
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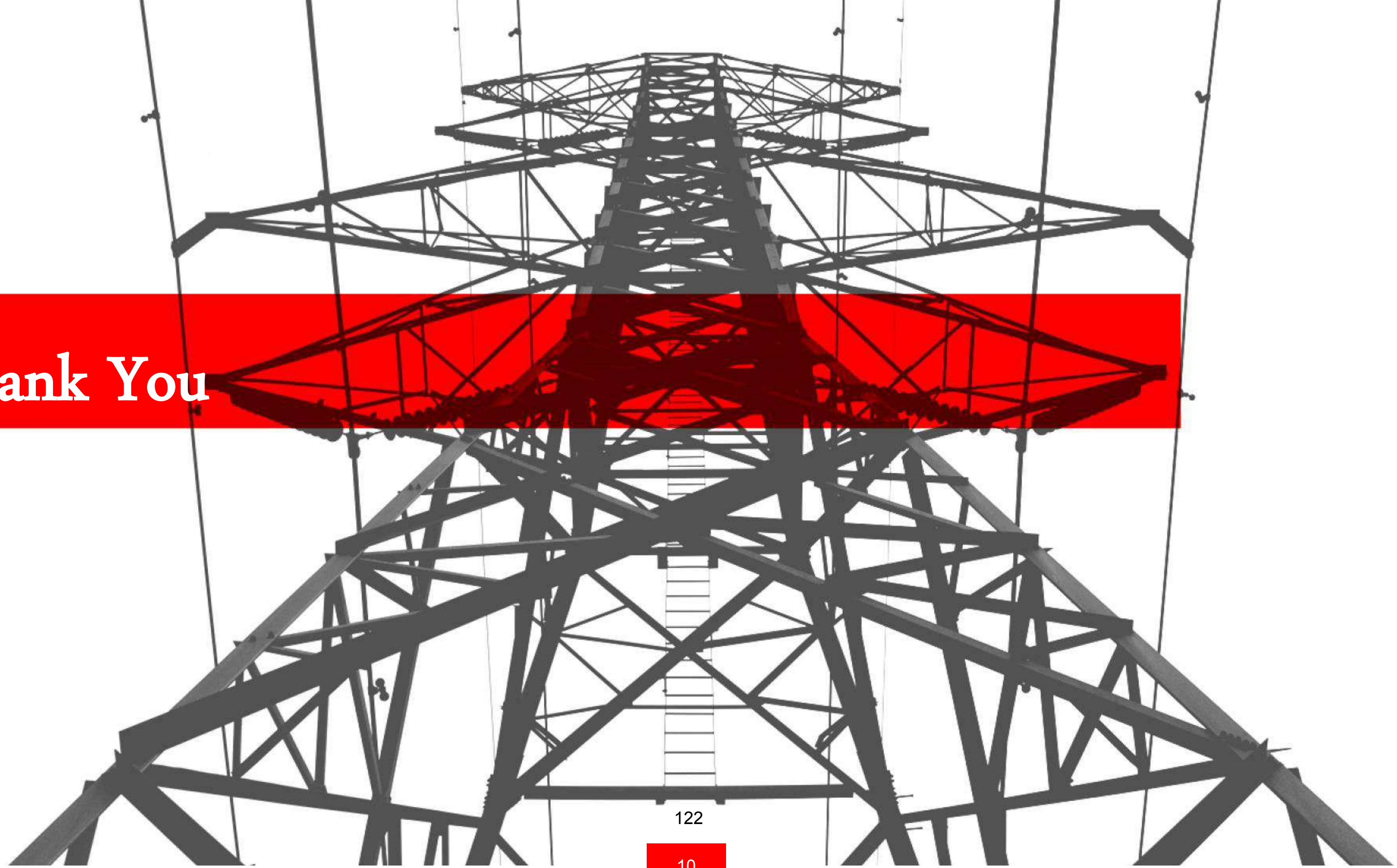
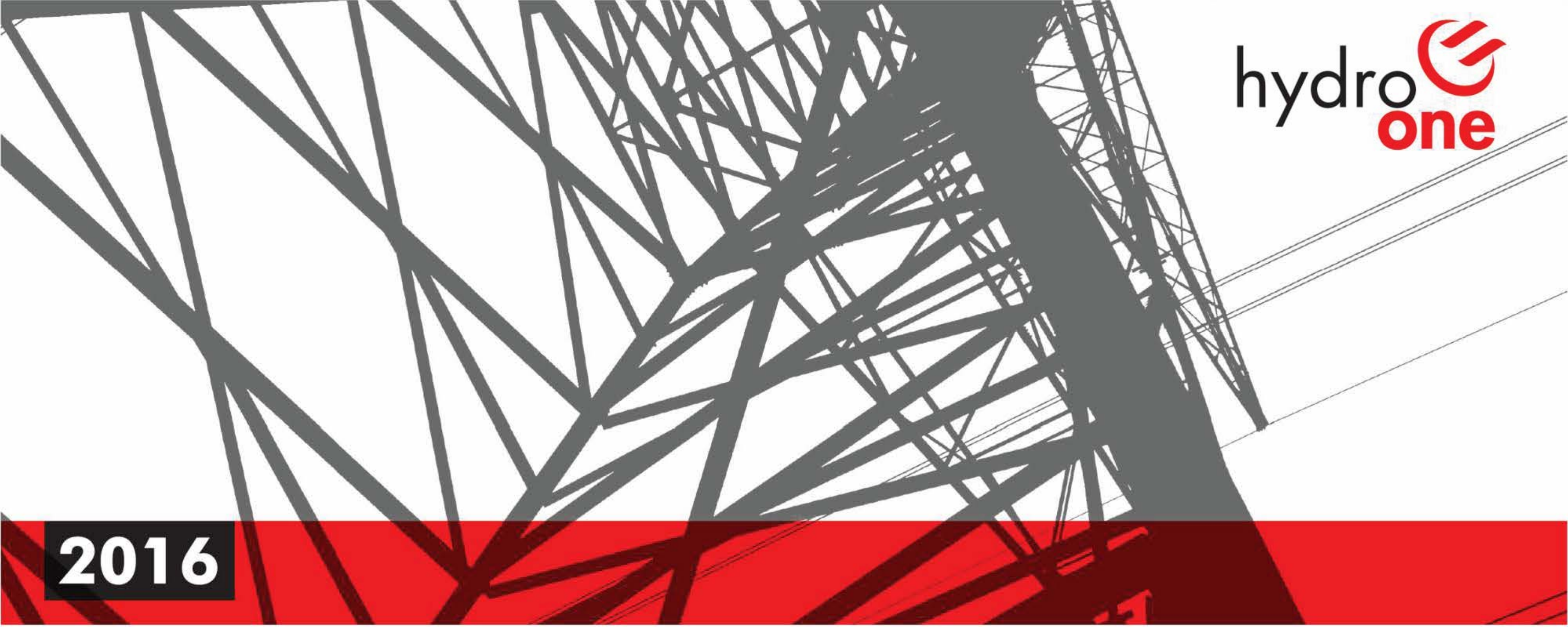
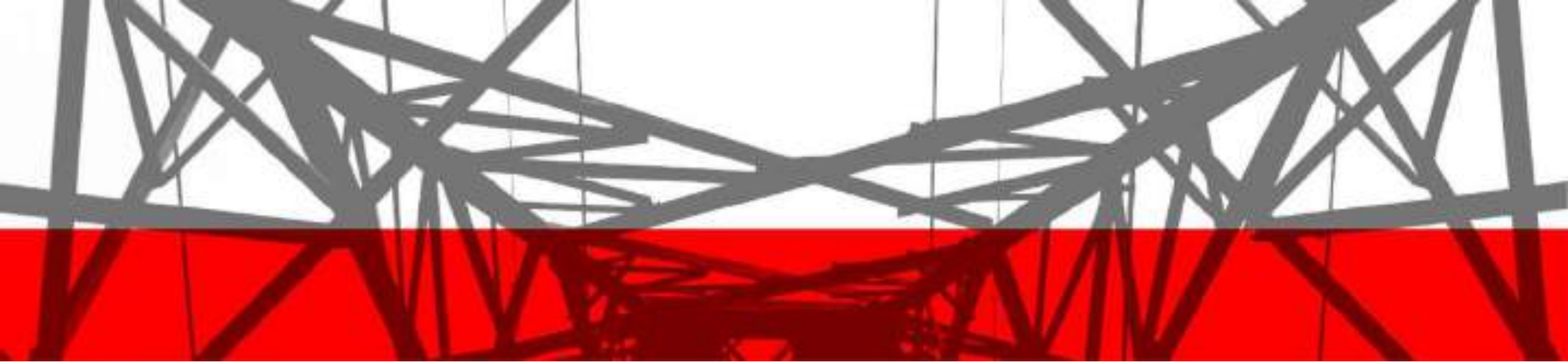




LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency

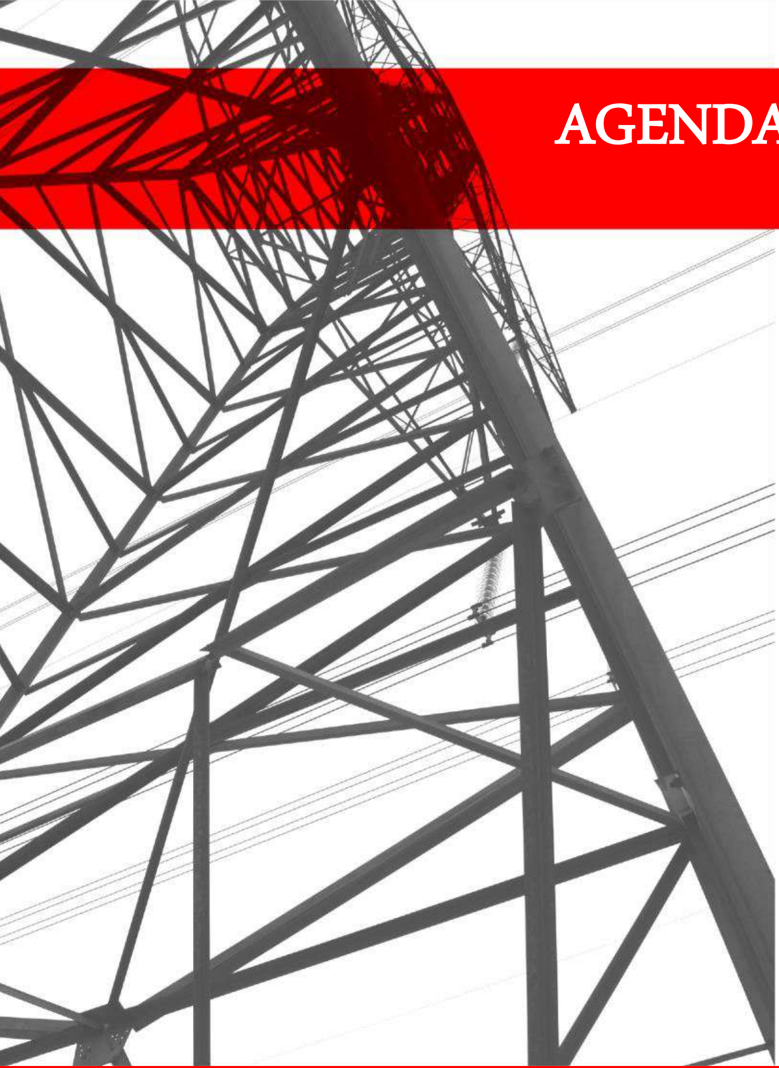


APPLICATION OF LiDAR

CK Ng

Director, Transmission Asset Management

Hydro One



AGENDA

- Hydro One’s Current Vegetation Practices
- Overview of LiDAR Technology
- Applications to Vegetation Management
- LiDAR Pilot
- Future Implementation

VEGETATION MANAGEMENT PRACTICES

- Hydro One's current vegetation management practice is to manage ROW's on a cyclical basis of 6 or 8 years, depending on the region
    - Line Clearing- remove or trim any trees along the edge of or off the ROW which may fall into an overhead conductor
    - Brush Control – removal of any non-compatible brush or trees located under a transmission line ROW
    - Condition Patrol – mid cycle inspection to identify and eliminate any vegetation that will not hold until the next LC/BC maintenance
- Minimum Vegetation Clearing Distance (MVCD) – the minimum distance between vegetation and a conductor that must be maintained to prevent flashover

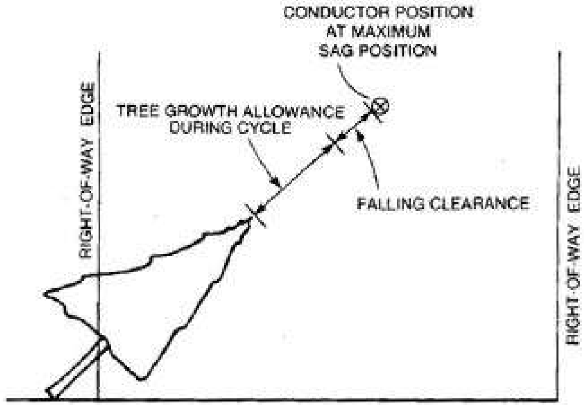
VEGETATION MANAGEMENT PRACTICES (CONT'D)

Voltage	HONI Falling Clearance		HONI Standing Clearance	FAC-003-4 MVCD
	Sound Trees	Danger Trees		
115 kV	N/A	1.0 m (3 ft.)	3.0 m (10 ft.)	0.6 m (2.0 ft.)
230 kV	N/A	2.0 m (7 ft.)	4.5 m (15 ft.)	1.3 m (4.3 ft.)
500 kV	3.0 m (10 ft.)	3.0 m (10 ft.)	6.0 m (20 ft.)	2.3 m (7.4 ft.)

VEGETATION MANAGEMENT PRACTICES (CONT'D)

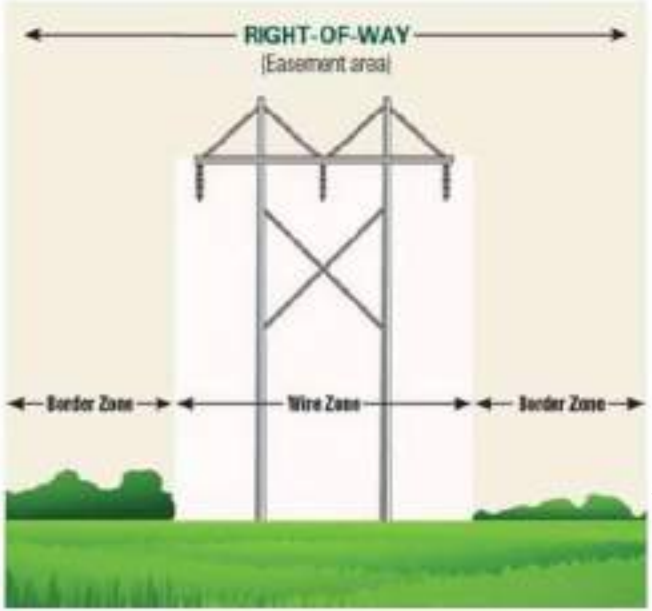
- All non-compatible vegetation is removed from the Wire Zone, the area directly beneath the conductor
- All unhealthy vegetation with the potential to fall into the conductor is removed from the Border Zone
- Hydro One's clearances account for vegetation growth until the next maintenance cycle

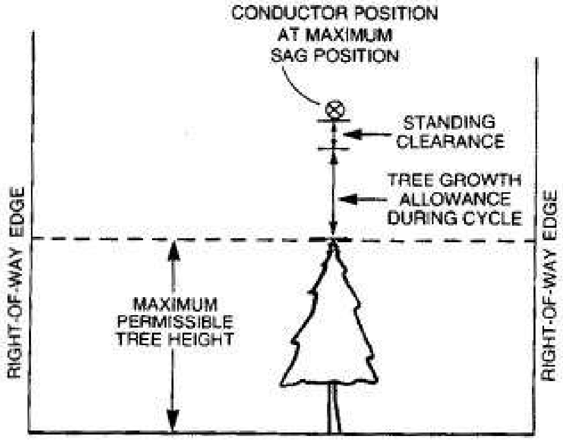
VEGETATION MANAGEMENT PRACTICES (CONT'D)



FALLING CLEARANCE

The minimum distance that can exist between the nearest conductor at its maximum sag position and a tree that may fall towards it from a position off the Right of Way.



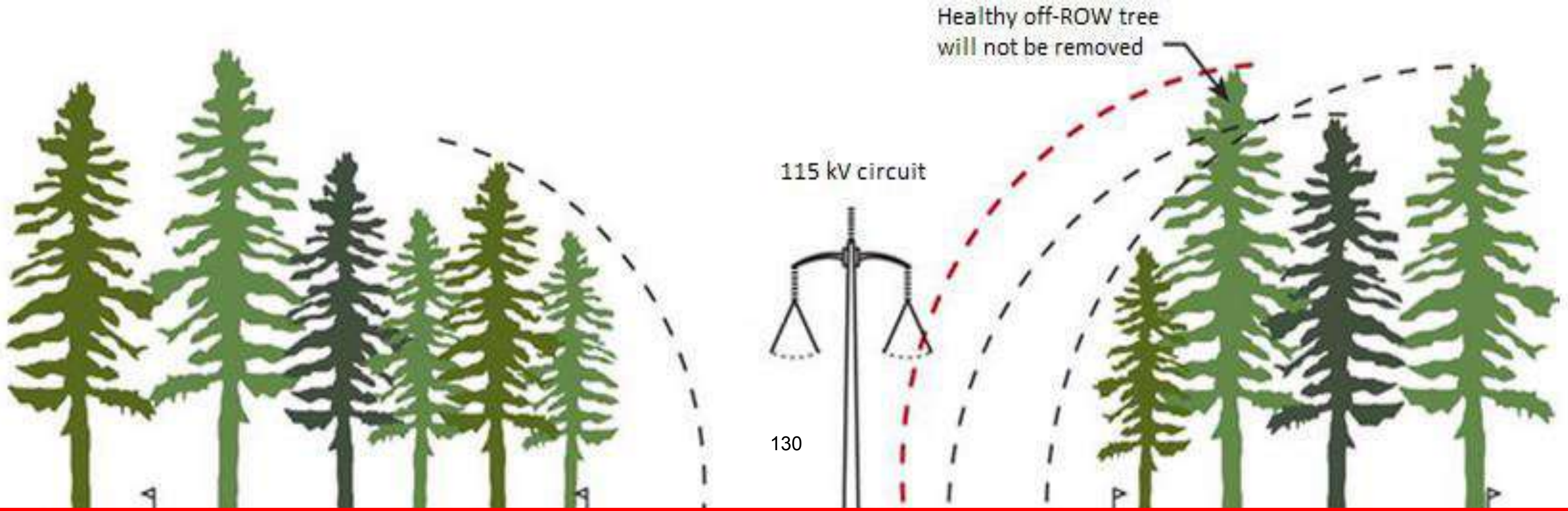


STANDING CLEARANCE

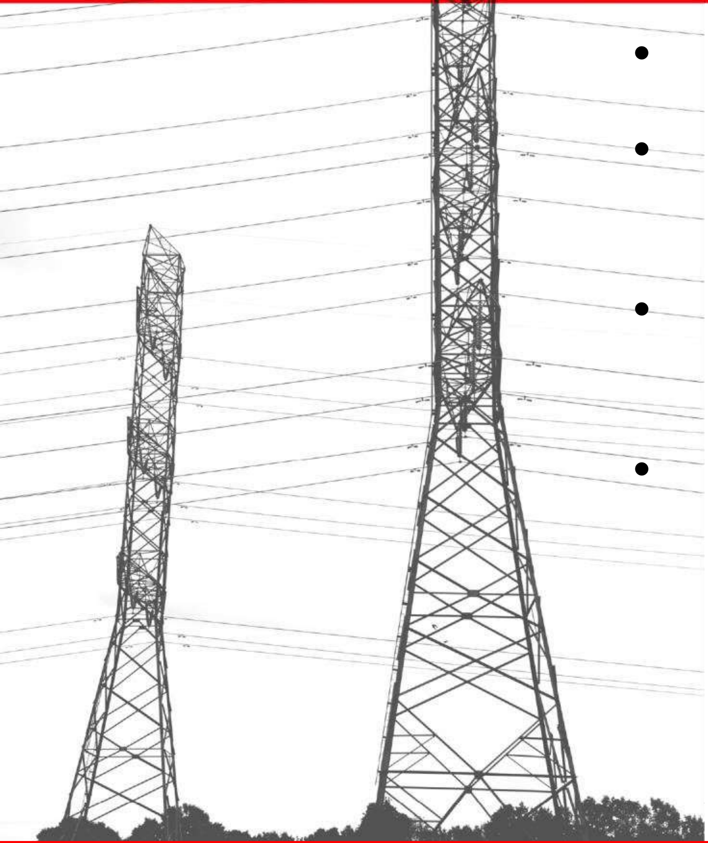
The minimum distance that can exist between a conductor at its maximum sag position and any vegetation. This clearance applies to any vegetation than can grow into the wire zone.

LINE CLEARING STANDARD

- 500 kV – Trees tall enough to fall within the 10ft falling clearance during the maintenance cycle are to be removed, regardless if they are healthy or not
- 115 & 230 kV – *only danger trees* tall enough to impede falling clearances during the maintenance cycle are to be removed
- Danger trees include split, hanging, uprooted, dead and diseased trees

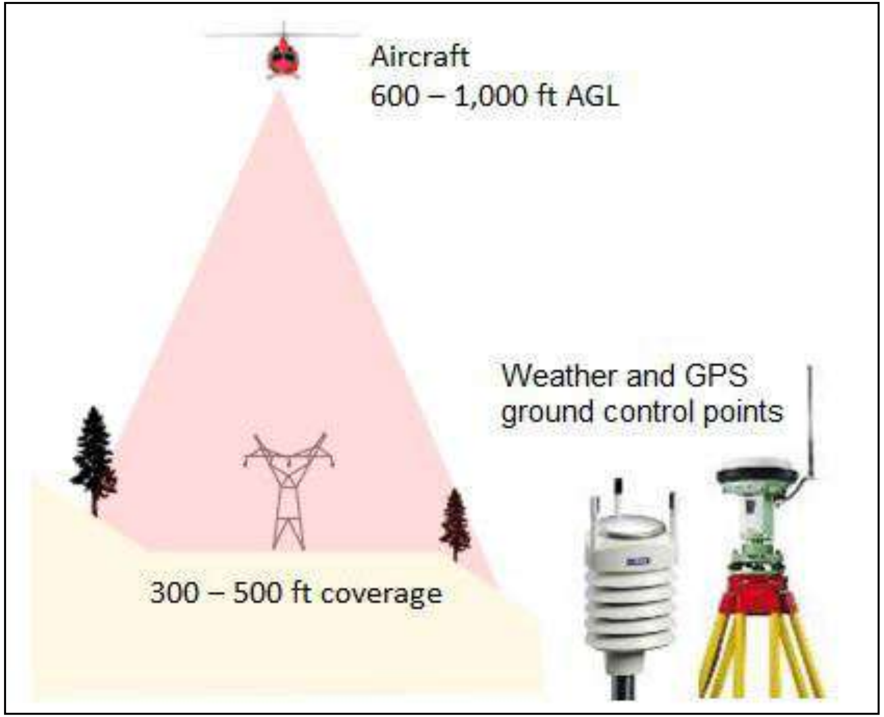


LiDAR TECHNOLOGY



- LiDAR – Light Detection and Ranging
- LiDAR technology is completed via aircraft and involves the use of light to calculate object distance and position
- The scanning laser is used to create high resolution maps of transmission lines
- Maps are used to:
  - develop engineering models
  - analyze maximum conductor swing and thermal ratings to detect vegetation growth

DATA COLLECTION



- Data collection can be completed via helicopter or a fixed wing aircraft
- Typical flying speed of 90 km/hr to create PLS-CADD engineering models
- Data points are collected at a rate of 30 points per square meter
- Horizontal accuracy of 0.3 m and vertical accuracy of 0.1 m
- GPS ground control points are used to determine precise coordinates and elevation for all transmission line components and vegetation

DATA PROCESSING

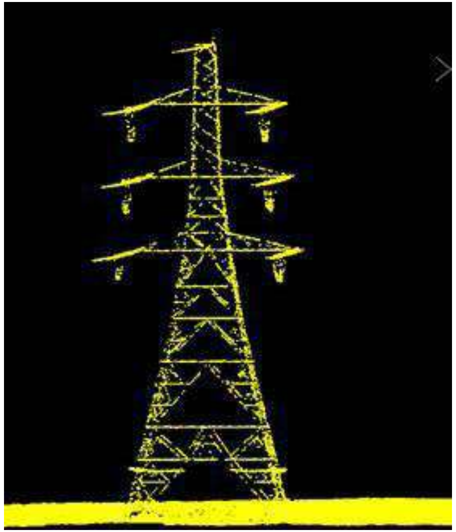
Basic Feature Code	Description
200	Ground
201	DTM Key
400	Water/Swamp
500	Wire
521-529	Shield Wire (project specific)
530-599	Phase Conductor (project specific)
600	Transmission Structure Centroid (under study)
610	Transmission Structure Centroid (other)
650	Shield Wire Point of Attachment (under study)
655	Shield Wire Point of Attachment (other)
660	Phase Conductor Point of Attachment (under study)
665	Phase Conductor Point of Attachment (other)
800	Vegetation Low (<1 m)
805	Vegetation High (>1 m)
810	Constructed Plant

- All data collected is processed with a basic feature code, classifying the data into categories
- Land below and adjacent to a transmission line ROW is grouped by land class, i.e. woody vegetation, parking lot, or residential

hydro one

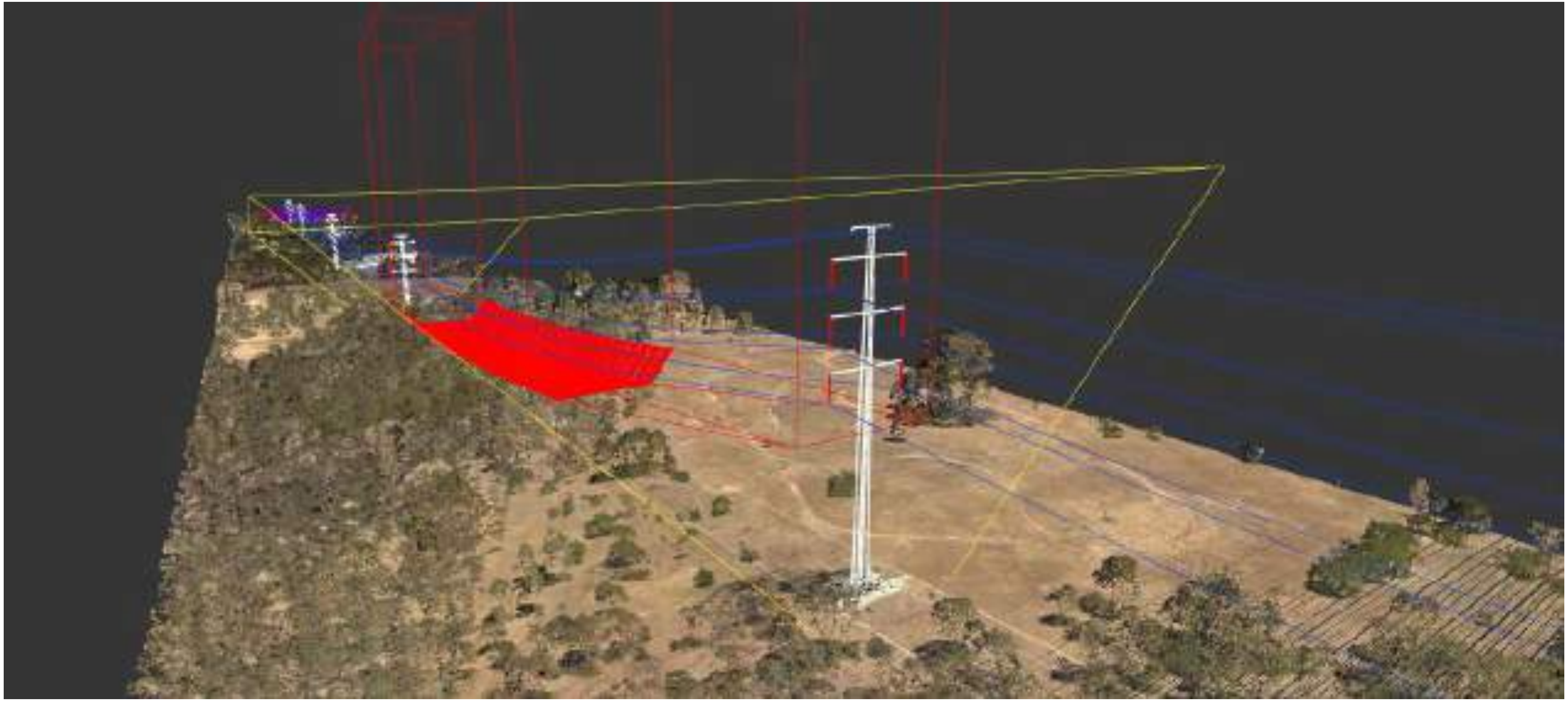
DATA PROCESSING

- The result of this data processing is a detailed engineering model of the transmission line and its surrounding vegetation
- Data processing results in an "as-built" model of the transmission line, clearing identifying conductor maximum sag and thermal ratings



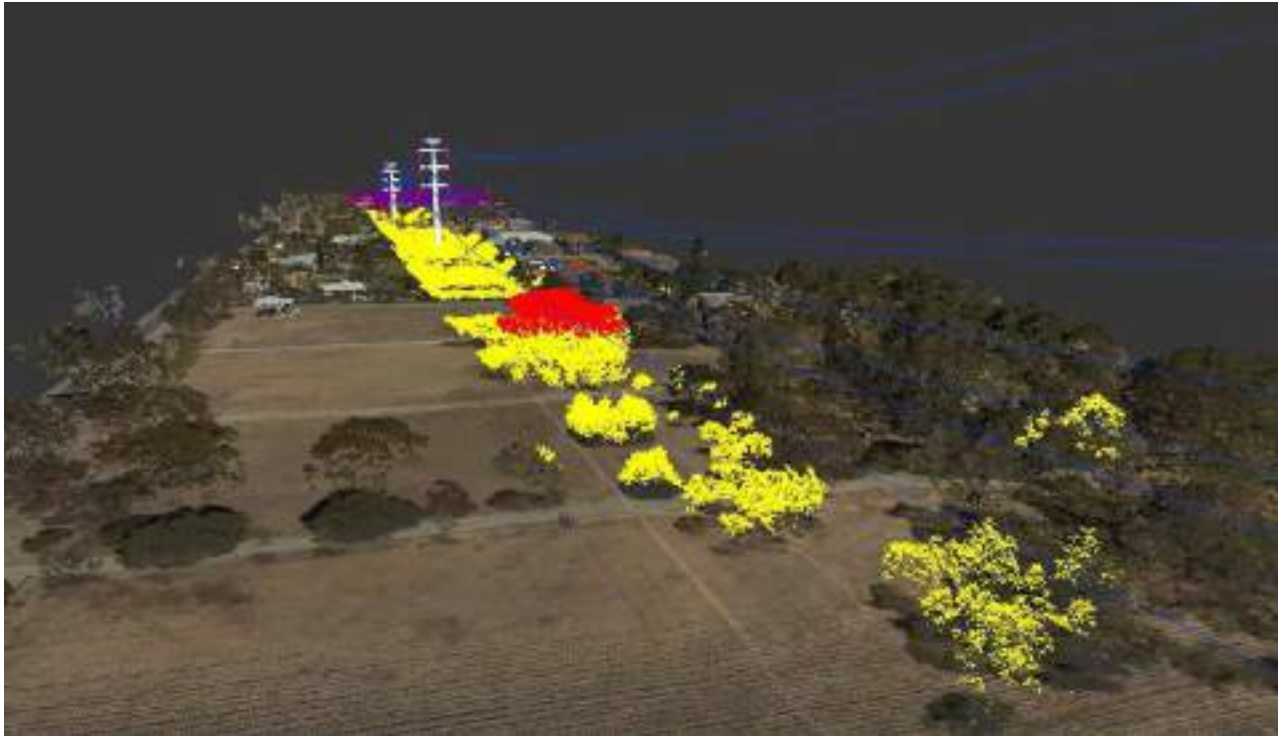
- Vegetation height, density, and type are all recorded and classified through LiDAR
- Tree height is compared to both Hydro One and NERC clearance standards. Any vegetation infringing upon these standards is flagged
- On the Australian circuit below, there are no violations to the minimum voltage clearing standards (MVCD)

APPLICATION TO VEGETATION MANAGEMENT (CONT'D)



APPLICATION TO VEGETATION MANAGEMENT (CONT'D)

- In this model of an Australian circuit, the vegetation highlighted in red is in violation of the MVCD
- Vegetation with the potential to grow into the MVCD in future is highlighted in yellow

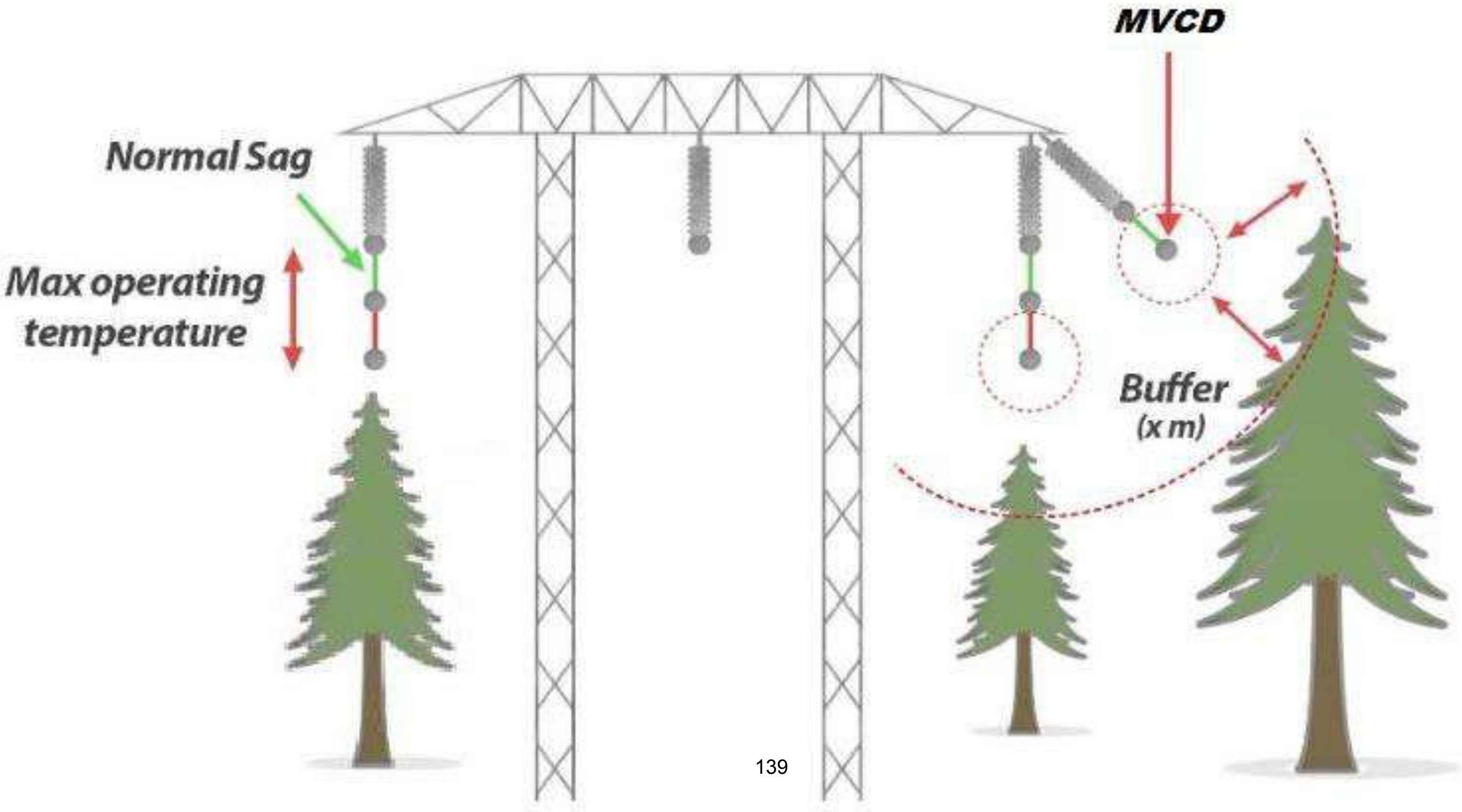


APPLICATION TO VEGETATION MANAGEMENT (CONT'D)

- Hydro One's clearance standards are more stringent than NERC FAC-003 compliance regulations. This allows us to create a buffer zone around the MVCD

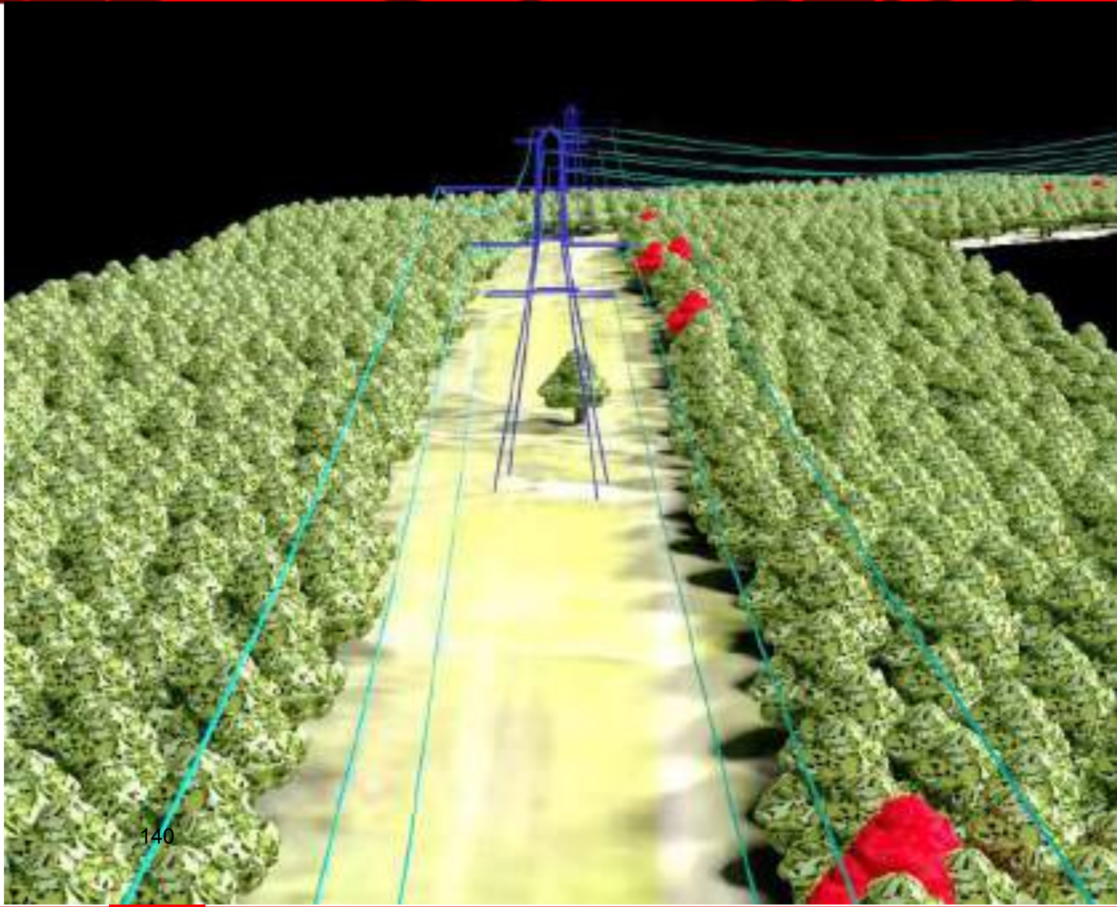
- LiDAR will identify any trees located within the buffer zone or that have the potential to exceed the MVCD when the line is operating at maximum sag

APPLICATION TO VEGETATION MANAGEMENT (CONT'D)



IMPROVEMENTS TO VEGETATION MANAGEMENT EFFICIENCY

- Prediction of tree growth patterns- optimization of maintenance cycle
- Identification of danger trees - unhealthy trees are flagged by LiDAR
- Identification of potential grow-ins and fall-ins
- Effective estimating of cost and labor required to complete maintenance
- Clear compliance to NERC standard FAC-003



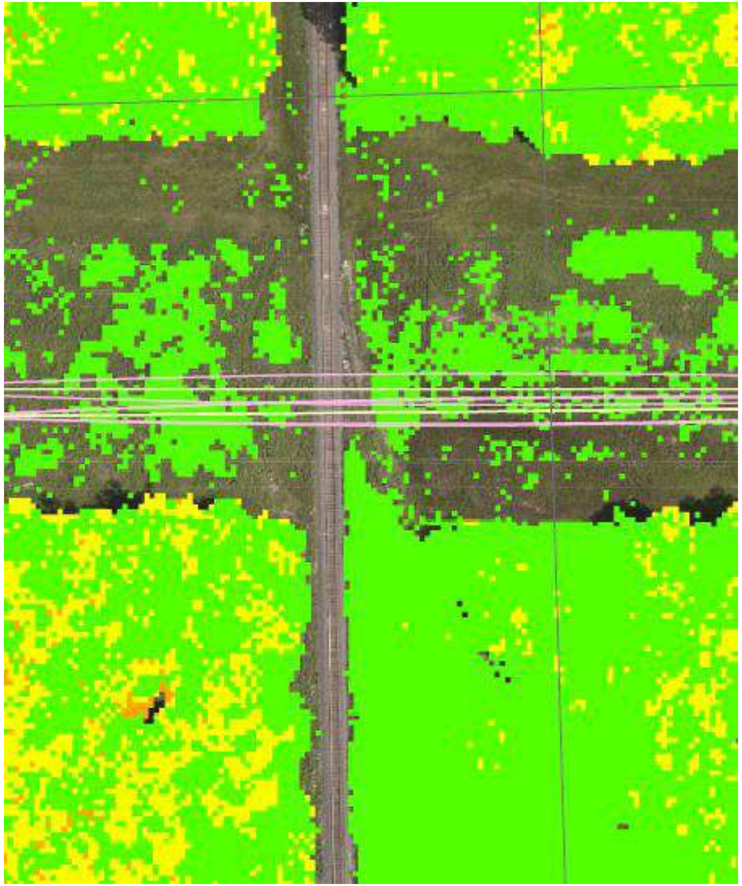
ENVIRONMENTAL IMPACT

- Despite Hydro One's best efforts there is still some risk of vegetation related outages due to environmental factors

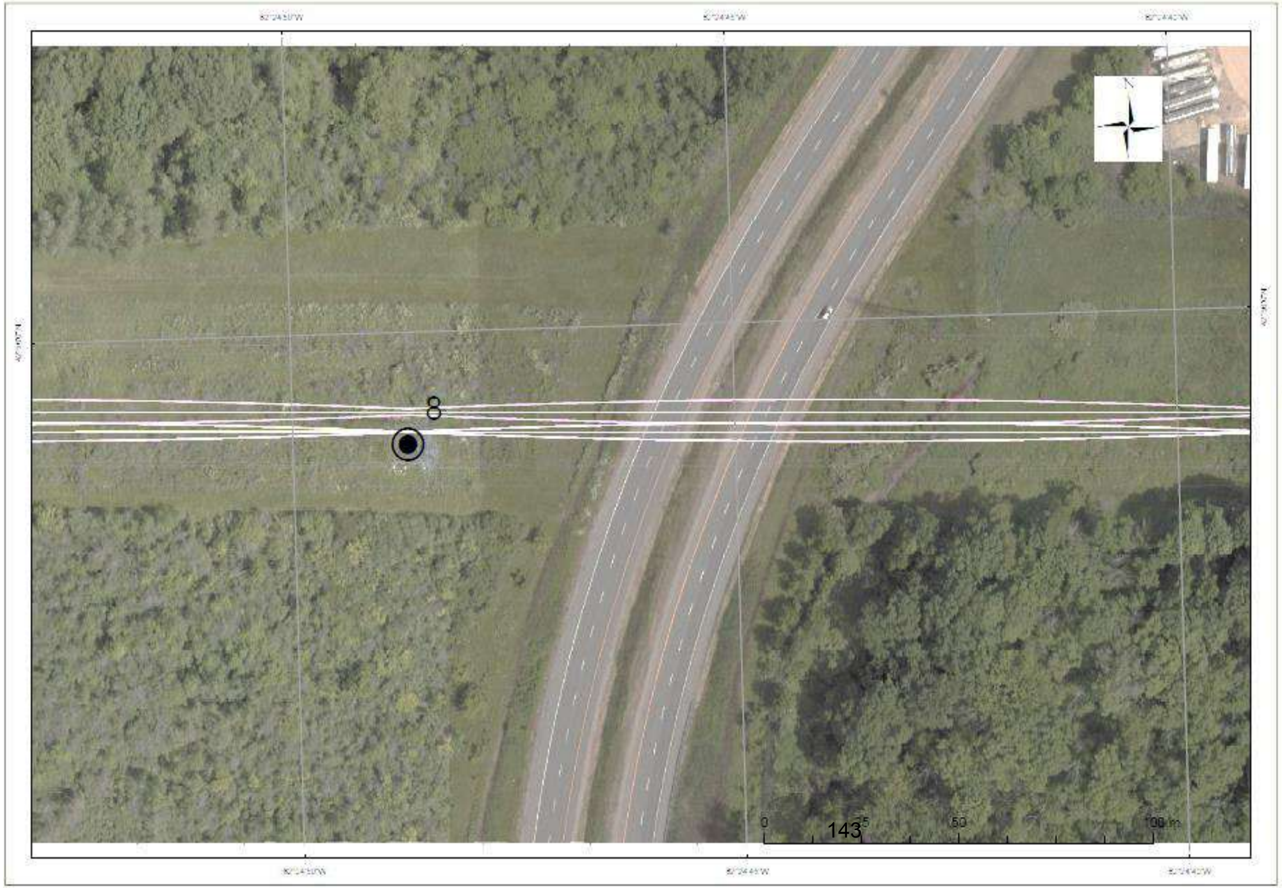
- As healthy, off-ROW trees are not removed when bordering a 115 or 230 kV corridor, the trees may fall into the conductor as a result of storms or animal activity

LiDAR PILOT

- Hydro One surveyed approximately 400 km of transmission and 100km of distribution circuits with LiDAR in 2016
- These circuits are located in the regions of Sarnia, London, Chatham-Kent, and Goderich
- LiDAR data was collected in June and processing has just been completed. Hydro One received PLS-CADD models and vegetation analysis for the pilot circuits in October
- Vegetation data is currently being analyzed and field verified to determine if any mitigation actions are required



LIDAR PILOT CASE STUDY- CIRCUIT B3N IN SARNIA



Title:	A3 VEGETATION EXCEPTIONS MAP
Circuit:	B3N
Circuit Name:	Sarnia Scott - MID RJCT Bunce
Sheet Number:	Sheet 6 of 20
Project Ref.:	NMCP16026
Coord. System:	Lambert Conformal Conic
Datum:	NAD83 (CSRS)
Units:	Metres
Survey Date:	18/06/2016
Version:	1.0
Published Date:	14/10/2016
Client:	Hydro One Networks Inc.

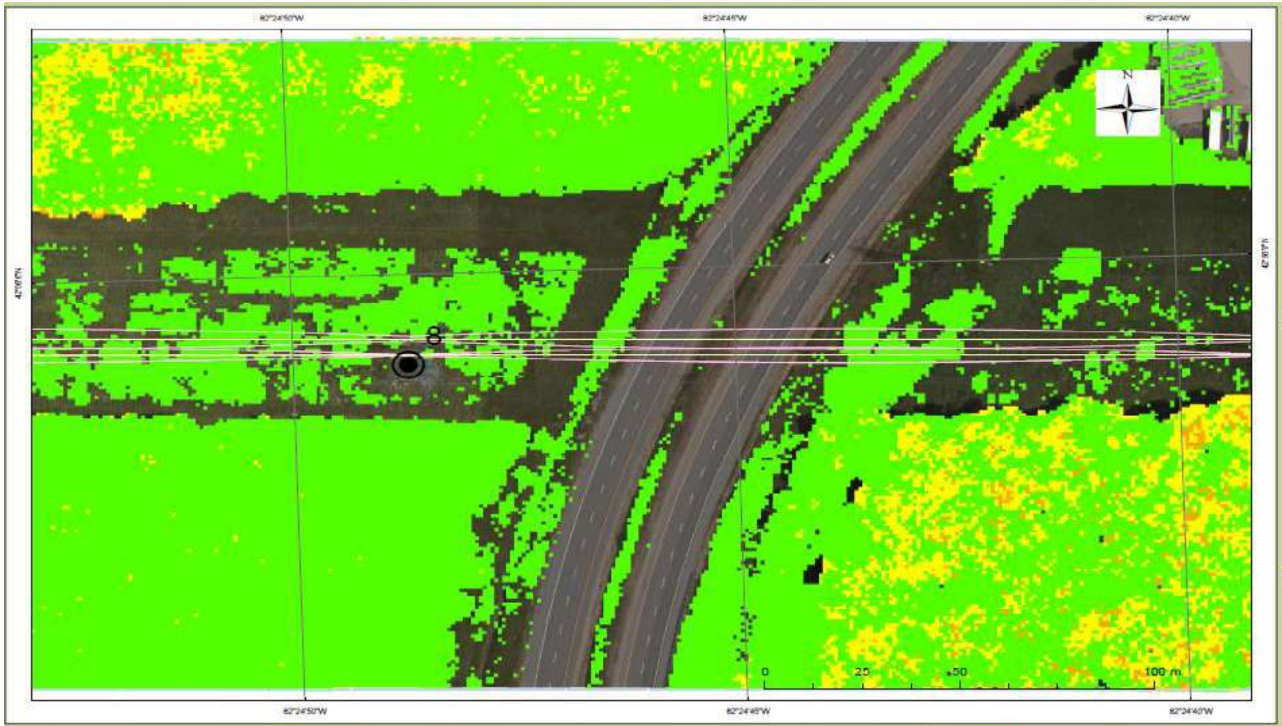
Legend

- Conductor
- Conductor Blow Out
- Other Circuit
- Other Circuit - Conductor Blow Out
- Right of Way
- Tower

MVCD Clearance Zones

- Fall in Tree
- Within MVCD 1m Grow in zone - Max. Sag
- Within MVCD 1m Grow in zone - Max. Blowout
- MVCD 1m -> 6m Grow in zone - Max. Sag
- MVCD 1m -> 6m Grow in zone - Max. Blowout
- MVCD 6m -> 15m Grow in zone - Max. Sag
- MVCD 15m -> 30m Grow in zone - Max. Sag

LIDAR PILOT CASE STUDY- CIRCUIT B3N IN SARNIA



Title:	A3 VEGETATION HEIGHT CLASSIFICATION FIELD MAP
Circuit:	B3N
Circuit Name:	Sarnia Scott - MID RJCT Bunce
Sheet Number:	Sheet 6 of 20
Project Ref.:	NMCP16026
Coord. System:	Lambert Conformal Conic
Datum:	NAD83 (CSRS)
Units:	Metres
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Version:	1.0
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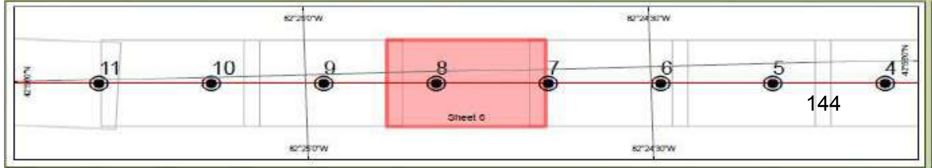
Client:	Hydro One Networks Inc.

Legend

- Circuit
- Conductor Blow Out
- Other Circuit
- Other Circuit - Conductor Blow Out
- Right of Way
- Tower
- Vegetation Height 1-5m
- Vegetation Height 5-15m
- Vegetation Height 15-30m
- Vegetation Height >30m

Vegetation Statistics

Height (m)	Area (m²)
Vegetation Height 1-5m	35052 m²
Vegetation Height 5-15m	4495m²
Vegetation Height 15-30m	463m²
Vegetation Height >30m	0 m²

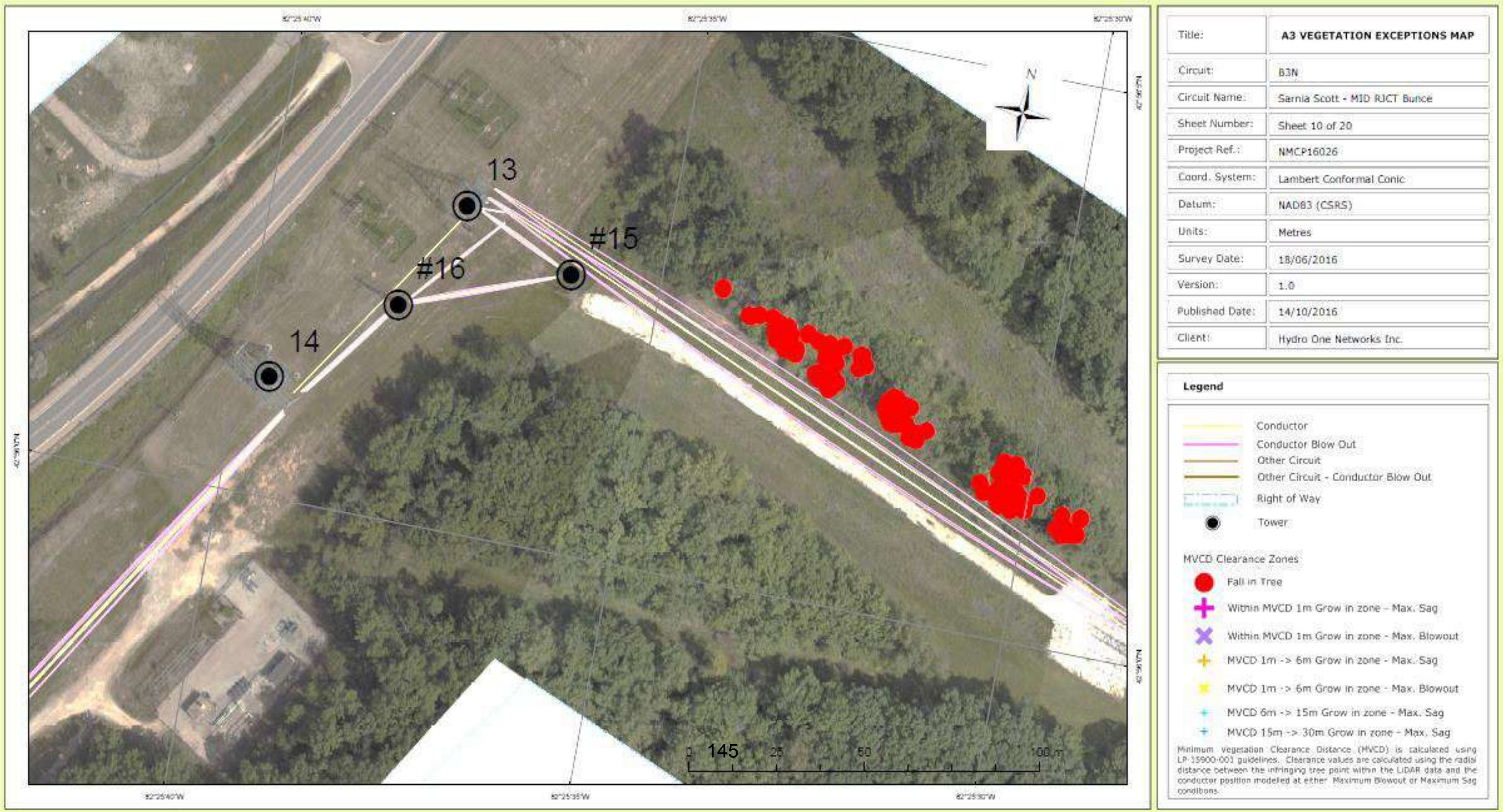


NM Group
Innovation In Infrastructure

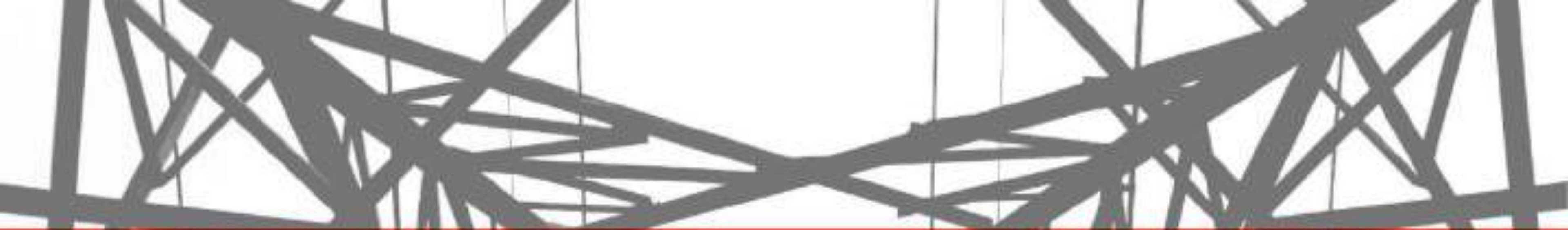
hydro one

NM Group Network Mapping Corp.
2200 HSBC Building
885 West Georgia Street
Vancouver British Columbia
V6C 3E8
+1 604.210.1815

LIDAR PILOT CASE STUDY- CIRCUIT B3N IN SARNIA



LIDAR PILOT CASE STUDY- CIRCUIT B3N IN SARNIA



LIDAR PILOT CASE STUDY – CIRCUIT B3N IN SARNIA

- As a result of LiDAR, we now have videos of our circuits and the surrounding vegetation
- In this video, the tall off-ROW trees correspond to the red dots seen in the LiDAR vegetation reports

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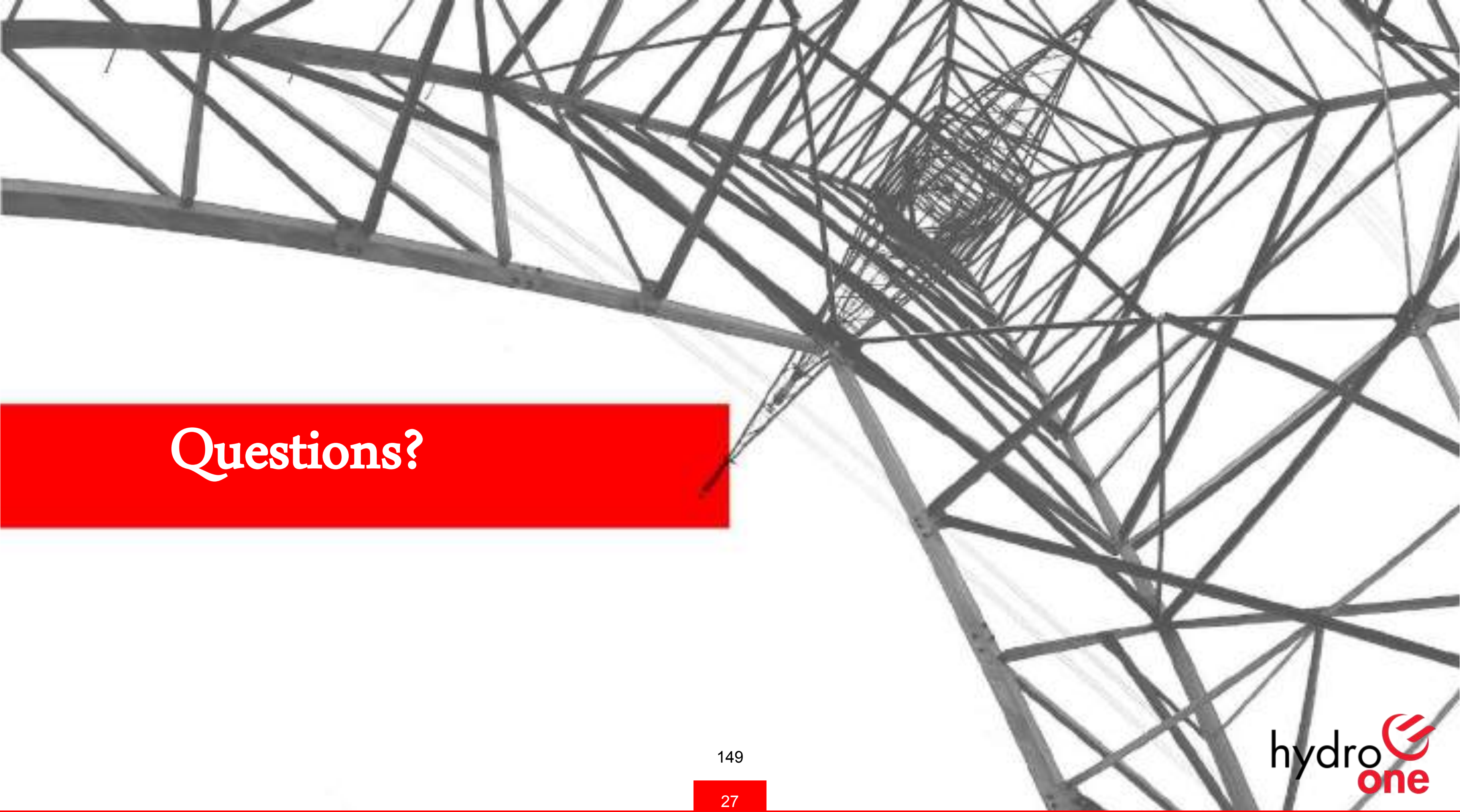
vlc-record-2016-11-06-11h32m37s-B3N_Sarnia Scott to MID RJCT Bunce_FlyThrough_180616_v1.avi-.mp4

hydro one

FUTURE IMPLEMENTATION

- Hydro One will schedule the mitigation of any vegetation risks identified during the LiDAR patrol
- Hydro One is currently developing a business case to justify the flying of our transmission lines with LiDAR
- Annual refresh using LiDAR will help to optimize maintenance cycle
- Potentially combine existing helicopter patrols with the LiDAR refresh to further optimize maintenance



Questions?

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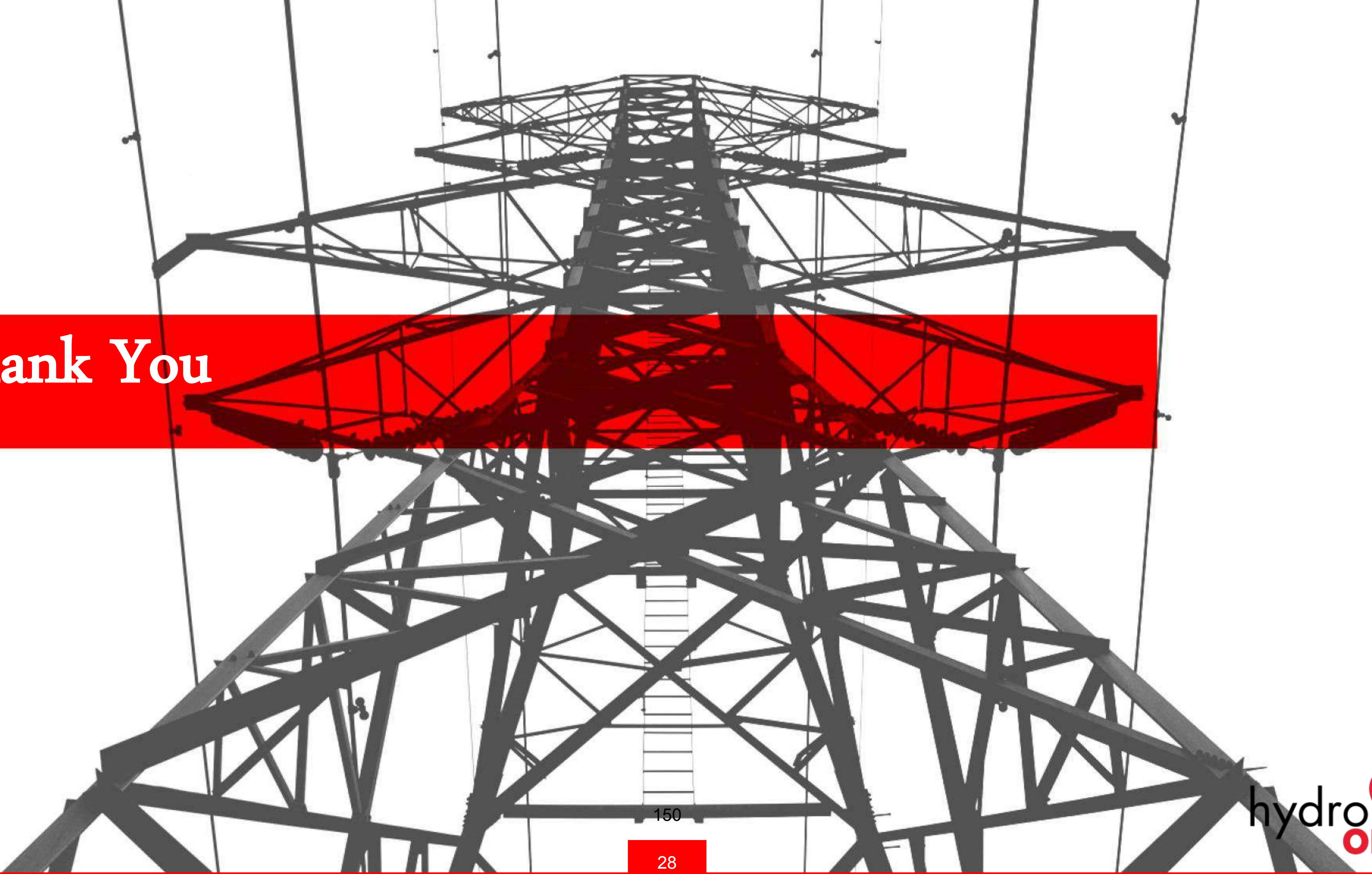
Thank You



150

Energy Efficiency Incentives through the Industrial Accelerator Program

Hydro One Customer Conference

Declan Doyle, Manager – Direct Customers, Conservation and Corporate Relations

November 22, 2016

Independent Electricity System Operator

Who We Are and What We Do

The Independent Electricity System Operator (IESO) – ensuring there is enough power to meet the province's energy needs in real time while also planning and securing energy for the future. It does this by:

- Long term and short term planning
- Enabling conservation by overseeing funding of Save on Energy programs offered by LDCs and Industrial Accelerator Program
- Ensuring supply through contracts, real time energy and operating reserve market and ancillary services such as regulation and blackstart
- Operating the IESO-controlled grid
- Engaging stakeholders and communities

ieso
Independent Electricity System Operator

Conservation Goals



Almost all electricity demand growth to 2032 to be met by energy efficiency & improved codes and standards

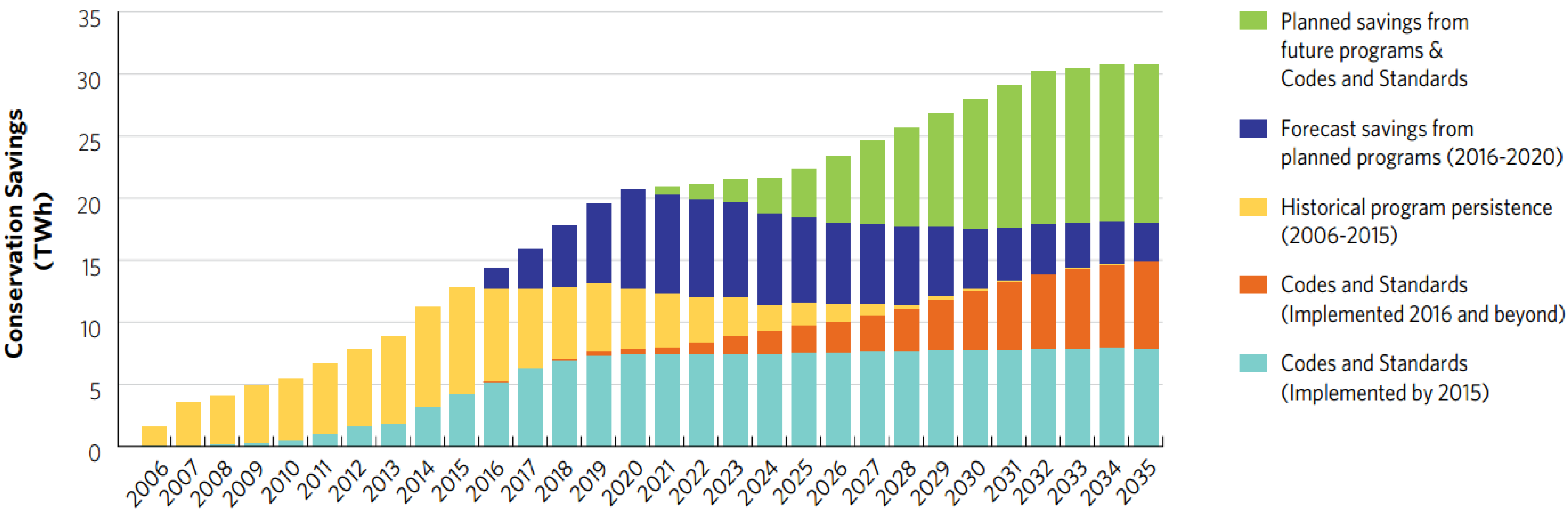
Goals:
8.7 TWh in 2020;
30 TWh in 2032

Demand Response to meet 10% of peak demand by 2025

ieso
Independent Electricity System Operator

Conservation Outlook

- All four outlooks reflect achievement of LTEP 2013 conservation targets and the Conservation First Framework



Building a Culture of Conservation

Pre-2011 Conservation → **2011-2014 Framework** → **2015-2020 Conservation First**

Success to Date

- **9.9 billion kilowatt-hours** of electricity savings through SOE programs and changes to codes and standards in the past 10 years
- **6,553 gigawatt-hours** of energy savings between 2011 and 2014 through the SOE suite of programs
- **928 megawatts** of demand reduction for the province
- **9.8 million products** purchased using Save on Energy coupons
- **5,000 people** participated in IESO-supported training programs between 2011 and 2014
- **12 LDCs** achieved over 80% of both energy and demand targets

Conservation Programs for Industrial Customers

Industrial Accelerator

- For transmission-connected facilities
- Must apply through your IESO Business Manager

SAVE ON ENERGY
POWER WHAT'S NEXT

- For distribution-connected facilities
- Must apply through your LDC

*Minor differences in incentives and contracts between the two programs

Program Streams

Process & Systems

Small Capital Projects

Retrofit

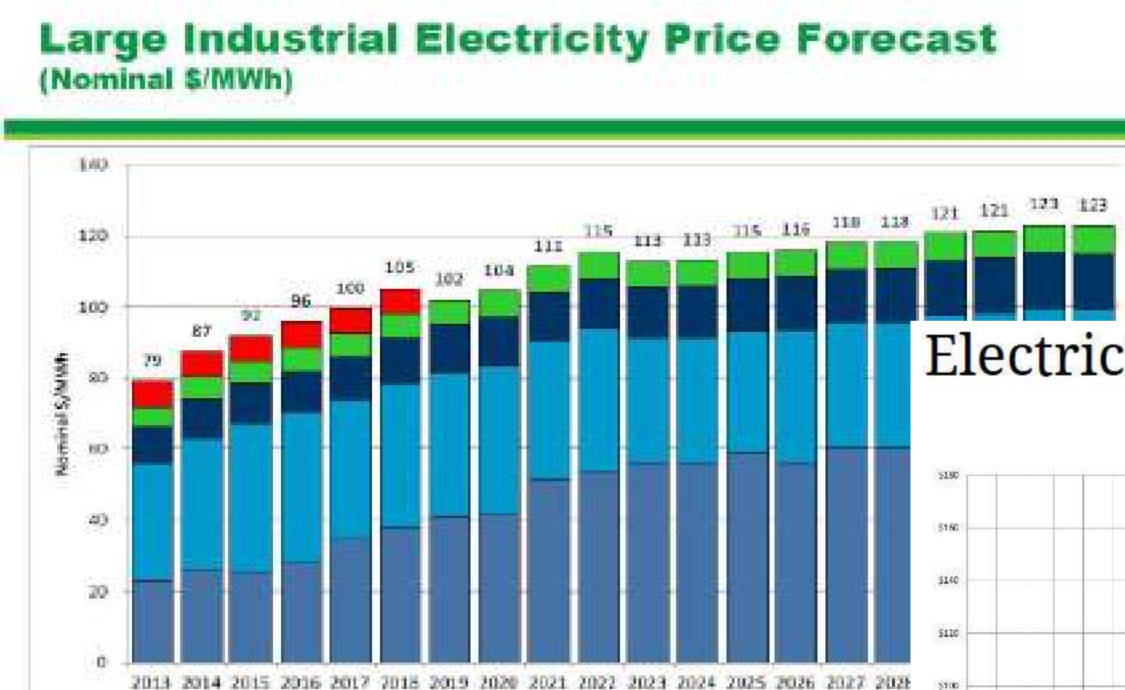
High Performance New Construction

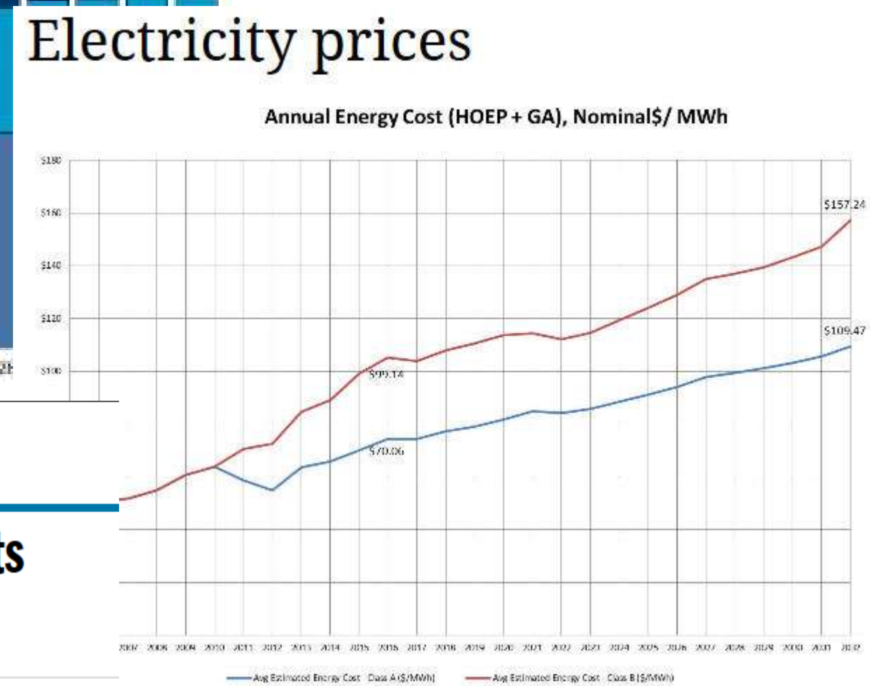
Energy Managers

Why Invest in Energy Efficiency?

- Improve productivity and competitiveness
- Cost and energy savings
- Reduced maintenance
- Longer equipment life
- Incentives improve payback and ROI
- Fast-track capital investment in major energy-efficiency projects

Solving your CFO's Concern






TORONTO & GTA ONTARIO CANADA WORLD WEIRD ARCHIVES

NEWS ONTARIO

Ontario industries hammered by energy costs

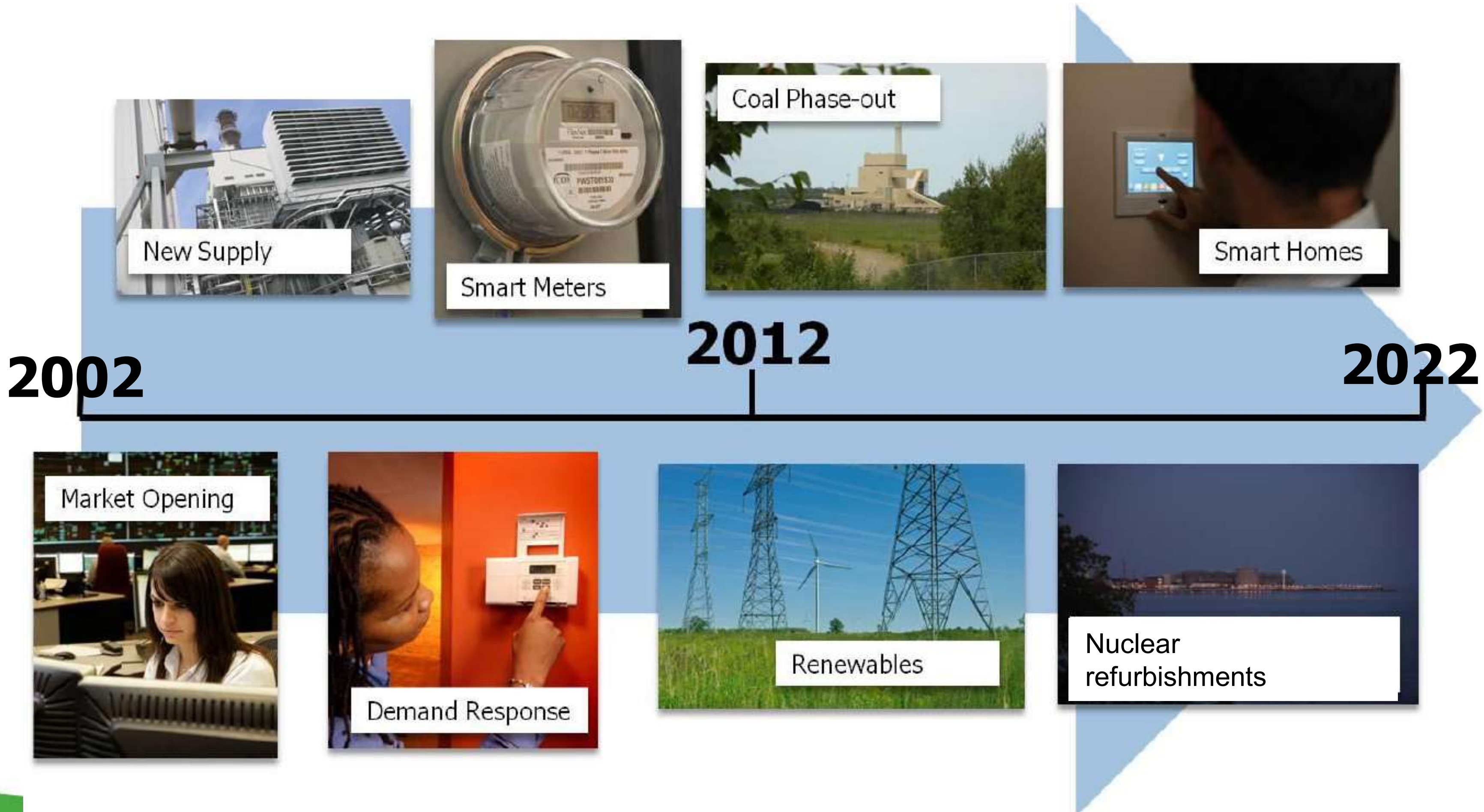
BY ANTONELLA ARTUSO, QUEEN'S PARK BUREAU CHIEF

FIRST POSTED: SATURDAY, MAY 16, 2015 07:00 PM EDT

Range of Options to Participate

- Opportunity Accelerator
- Engineering Studies
- Energy Manager Funding
- Long-Term Capital Projects
- Short-Term Retrofit Upgrades
- Training and Development Participation

Two Decades of Change



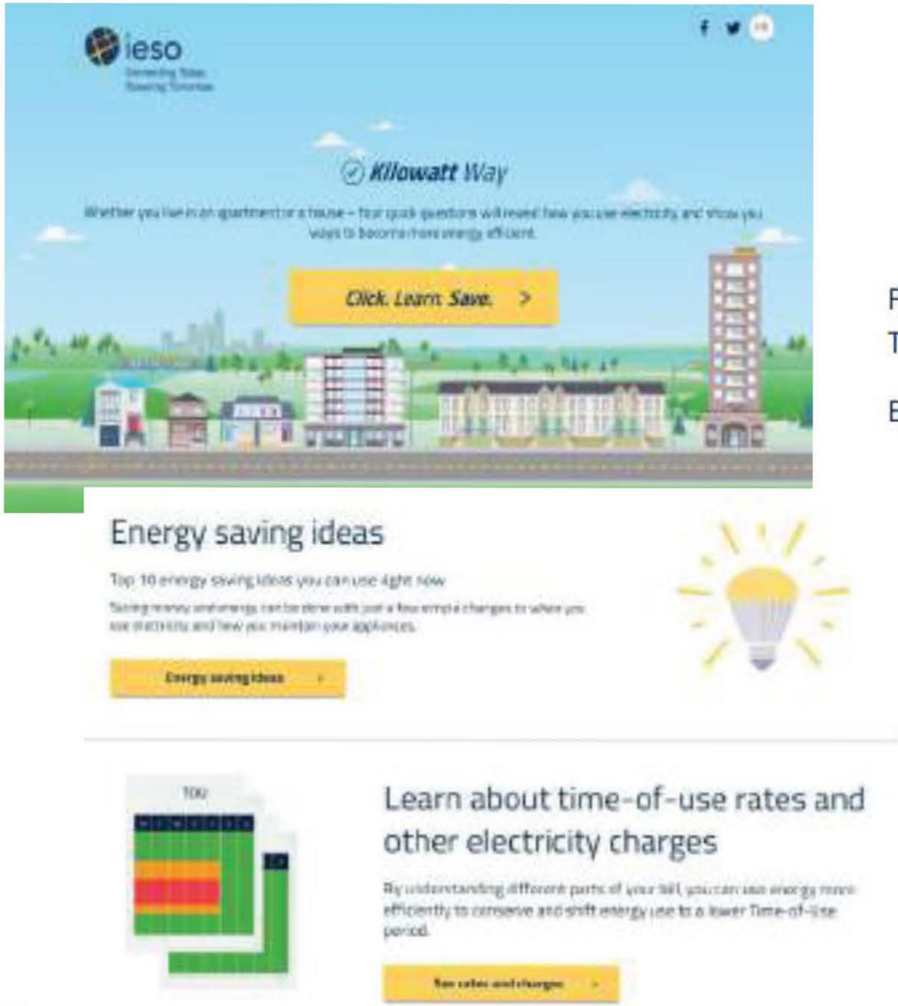
Landscape

ieso
Independent Electricity System Operator

Flexible, Creative and Innovative

- Conservation First Framework
- Streamlined processes
- Collaborative and complementary approach
- Innovation funding
- Stakeholder Engagement

IESO Resources – *Keep in Touch*



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Connecting Today.
Powering Tomorrow.

Phone: 905.403.6900
Toll-free: 1.888.448.7777

E-mail: customer.relations@ieso.ca

ieso.ca
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linkedin.com/company/ieso
facebook.com/OntarioIESO

SAVE ON ENERGY
POWER WHAT'S NEXT

saveonenergy.ca
twitter.com/saveonenergyONT
facebook.com/saveonenergyFORHOME

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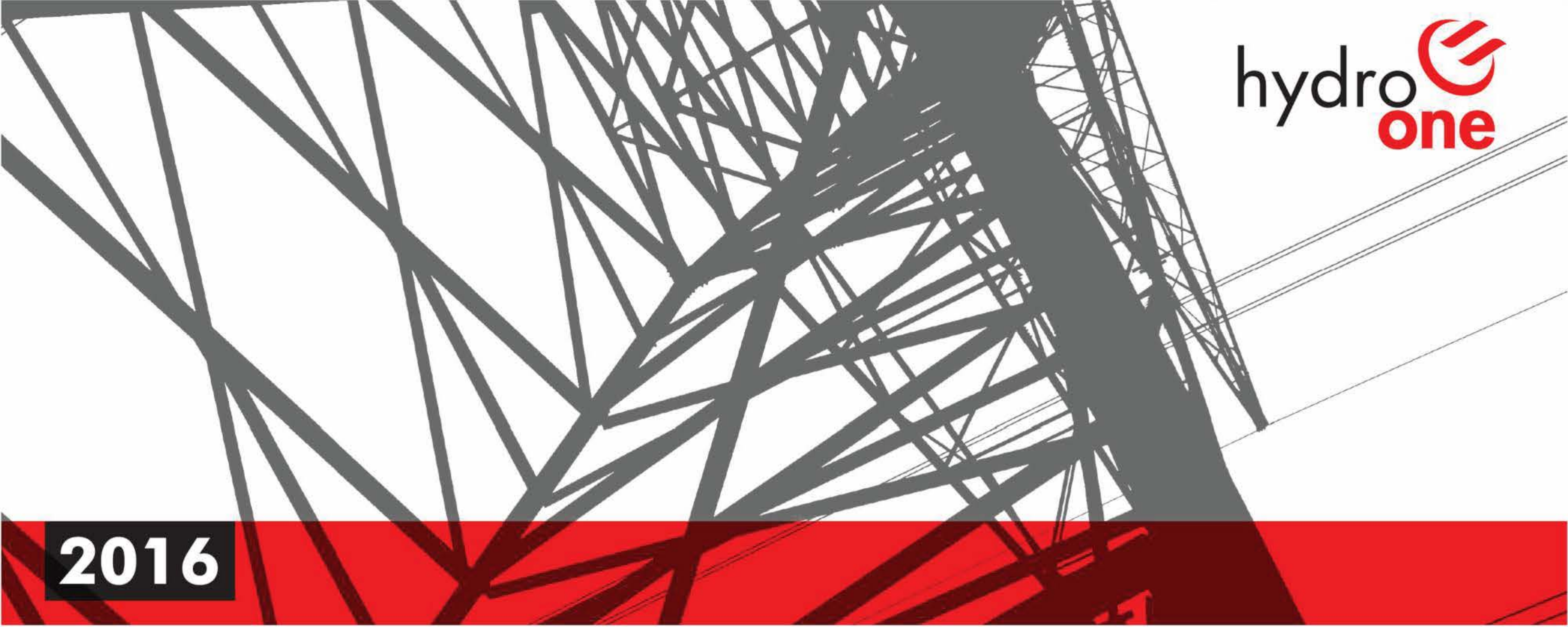
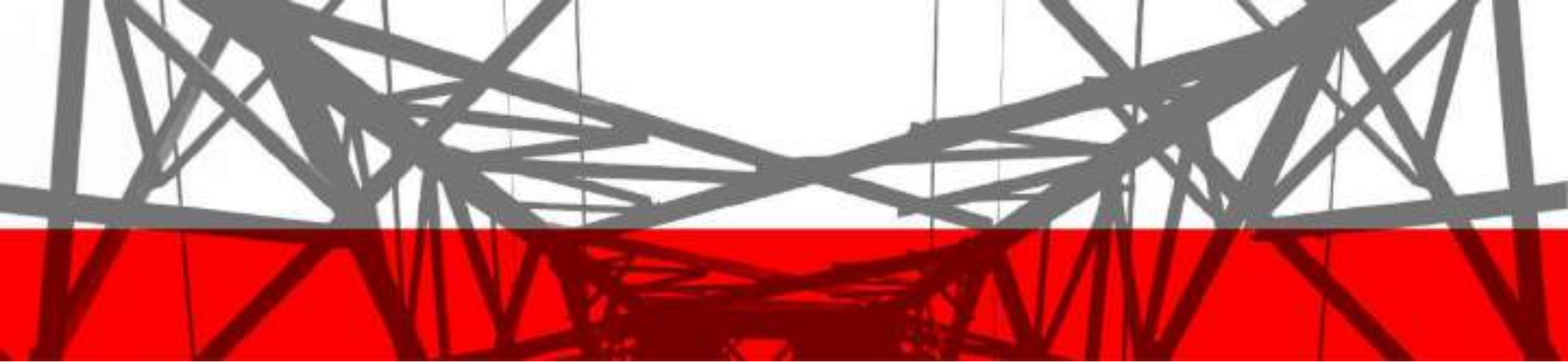


LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



OUTAGE PLANNING

Jason Boniface

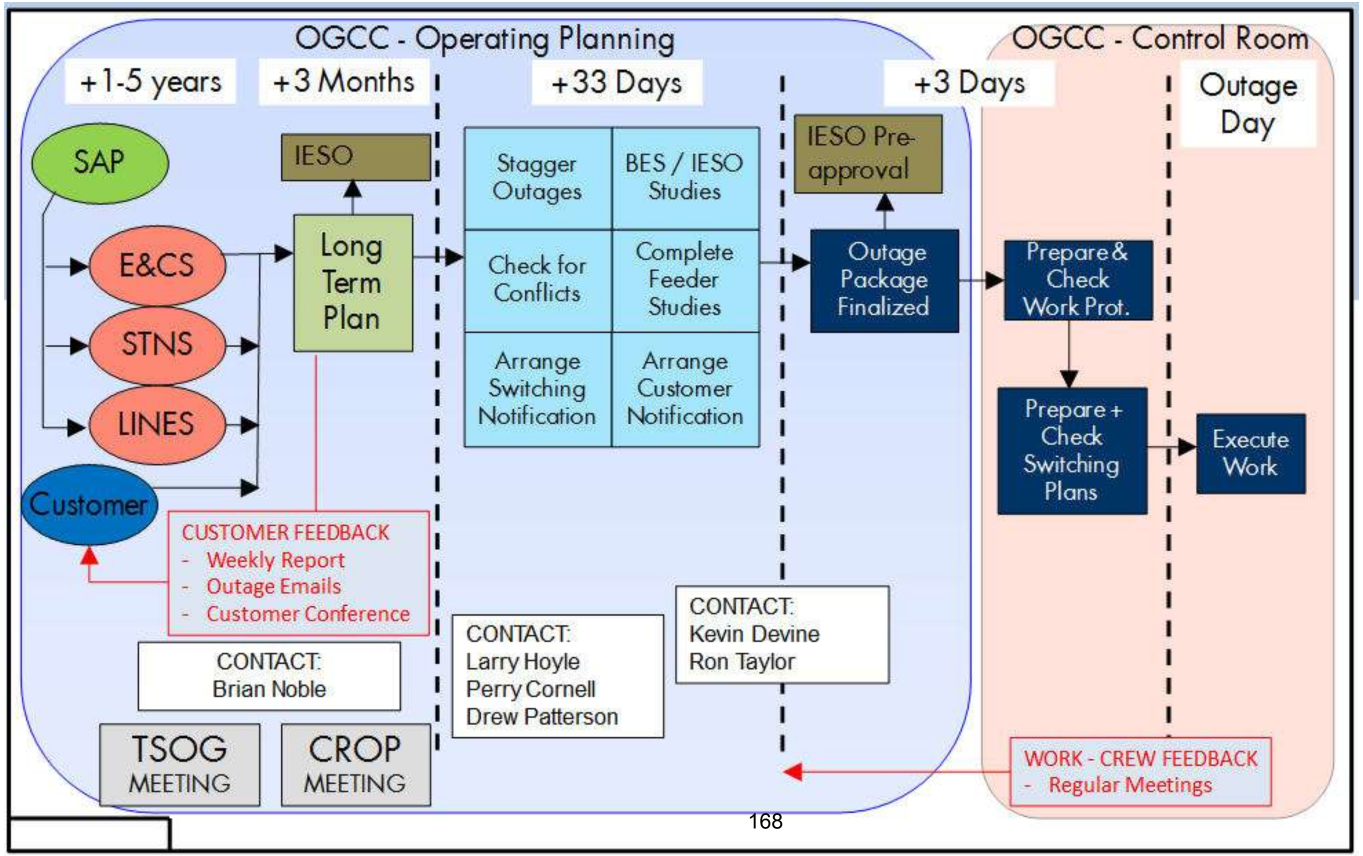
Manager, Grid Operations

Hydro One

OUTAGE PLANNING GOALS

- Engage all customers in outage planning process
- Meet customers' outage needs
- Meet Hydro One's outage needs
- Gain efficiencies, and reduce multiple outages, bundling of outages is a key driver
- Collectively create a successful outage plan as far ahead as possible
- TSOG (Transmission System Outage Grouping) is the platform used to achieve this

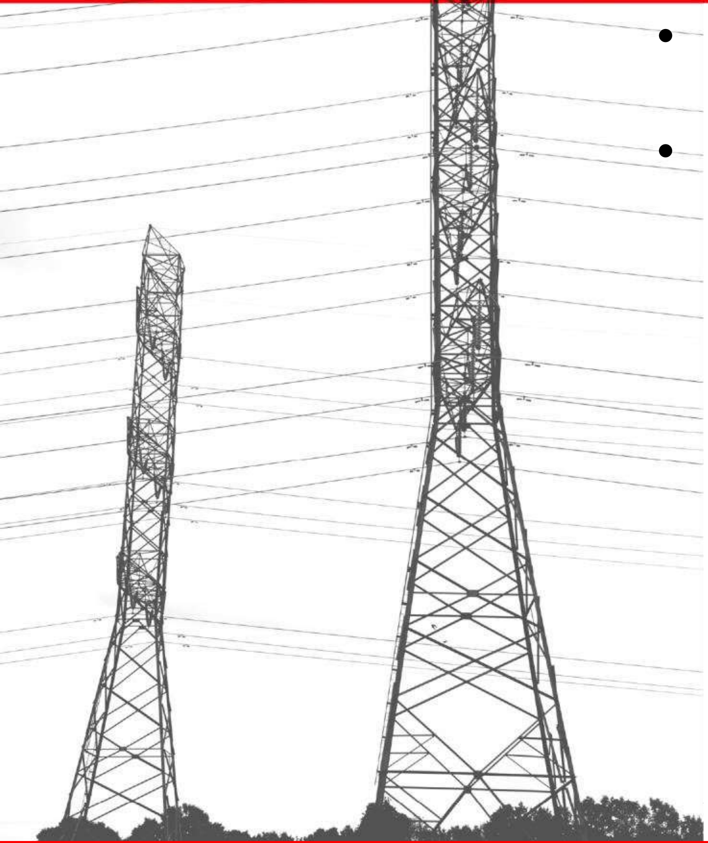
HYDRO ONE OUTAGE TIMELINE- Sector 4



PLANNING PROCESS FOR GENERATORS

- Beginning of Q3, letters sent requesting customers to provide Hydro One details of outage planning in 2017
    - Feedback allows Hydro One to coordinate outages based on customer outage times
        - ✓ Bundling opportunities
        - ✓ Avoid conflicts with other outages
        - ✓ Avoid impact to elements that may not be directly connected, however impacted by system constraints
    - Awareness of outages that may impact Hydro One equipment
- TSOG meetings are Bi-annual and outage discussions commence in the Spring and Fall

HOW CAN CUSTOMERS HELP?



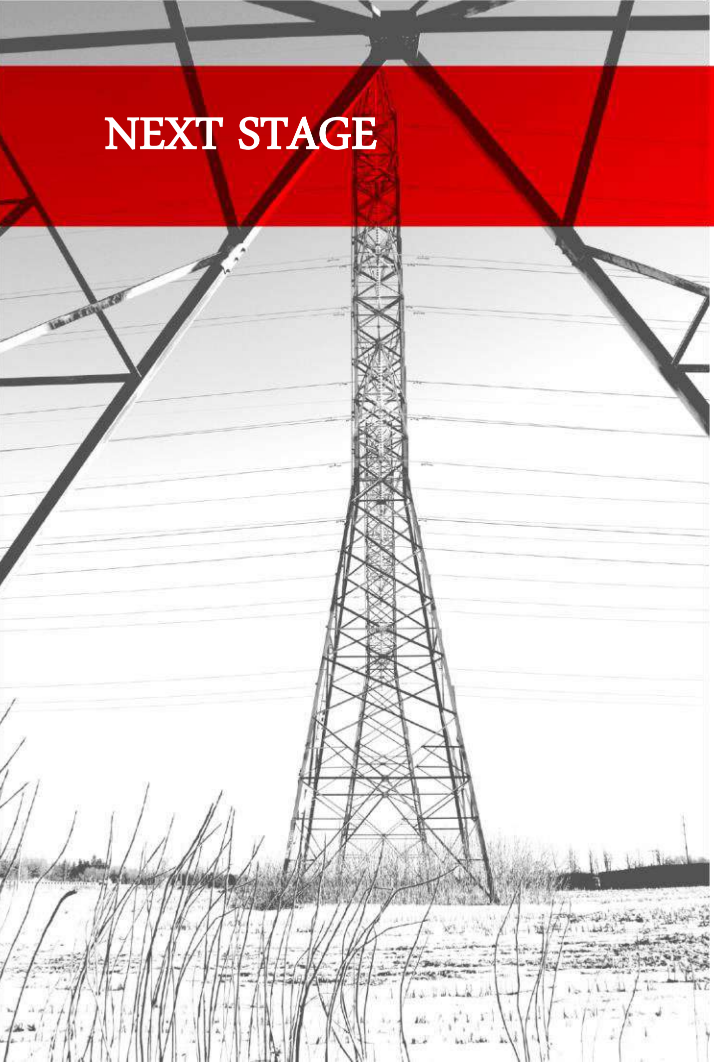
- Advise Hydro One of your outage plans for the following year
- Hydro One requests to provide outage requirements as far ahead as possible beyond
  1 year if possible
  - Results = better coordination of outages
  - Available for use during the TSOG meeting at end of Q3
    - ✓ Hydro One can develop outage plans with your available requirements

HOW CAN CUSTOMERS HELP? (CONT'D)

- Observations
  - Some entities have a 5 year plan available at time of request
  - Some entities do not have a plan until within the year
- Risks
  - Hydro One may not be able to adjust schedules for short notice outages
  - IESO requests outages involving Critical Equipment* for a Weekly or Quarterly Advanced Approval, therefore 17 days prior to 3 months respectively

**Critical Equipment is defined as equipment that impacts power system stability limits as listed in the System Control Orders*

- Requests
  - Take the time to complete the requests and advise Hydro One of your outage plans
  - Ensure that you apply to both the IESO and Hydro One for your outage requests that impact the Bulk Electric System



NEXT STAGE

End of Q3

- Planning groups within Hydro One all meet for 1 week to develop the outage plan for the upcoming year
  - Hydro One internal Lines of Business come to the meeting with planned work for upcoming year to schedule
  - Long Term NMOs have the customer outages that were provided
  - If we did not receive feedback from customers,
    the planning group will attempt to plan
    as per historical past practices

NEXT STAGE (CONT'D)

- Outages are captured into our Network Outage Management System- NOMS
- Upon entry into NOMS:
  - Requests from Hydro One are forwarded to IESO for approval
  - Weekly customer reports are now generated for outages impacting your facility
  - The NMOs will attempt to include customers on a report even if not directly impacted by the outage, however we are aware that an outage to this system element will still impact- P502X will effect output of multiple generators

CUSTOMER CONFERENCES

- October – November
    - Long Term Planners meet with smaller regional groups of customer to review outage plans
        - Opportunity for more detailed discussions
        - Customers can provide input on outage time to better respect their operations
        - Advise customers of our planned work that may impact their operations
        - Review opportunity to bundle Hydro One and Customers planned work

- Throughout the year for large complex projects involving customers, Planning will hold specific project meetings to
  keep all groups engaged and aware of on going work

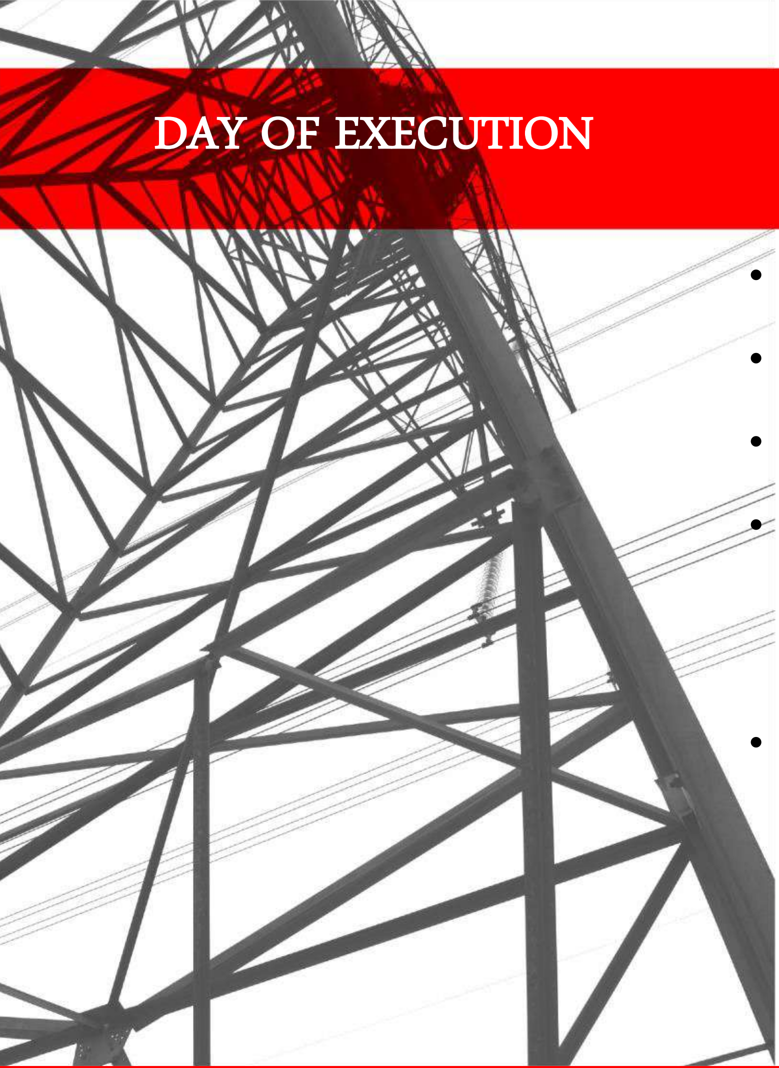
33 DAYS TO EXECUTION

- Operating Planning within this time frame will have the Short Term Planner review system conditions for outage to proceed
  - Review if any changes in system have occurred such as a forced outage
  - Load forecasts closer in

- Advise Customers of outage and impact

- Controllers will prepare all Work Protection and should have received all requested Supporting Guarantee request with a minimum of 10 days prior to outage date

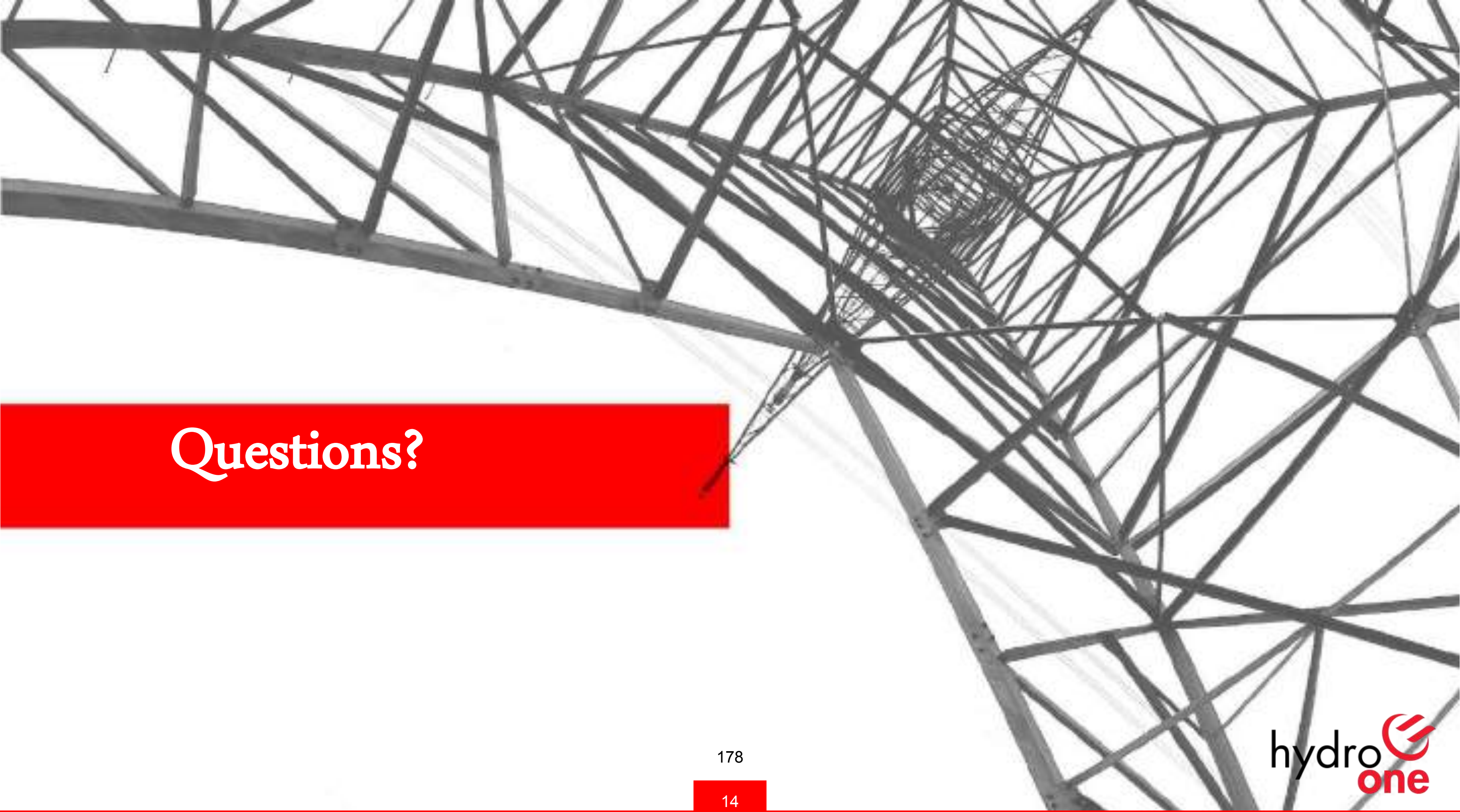
DAY OF EXECUTION



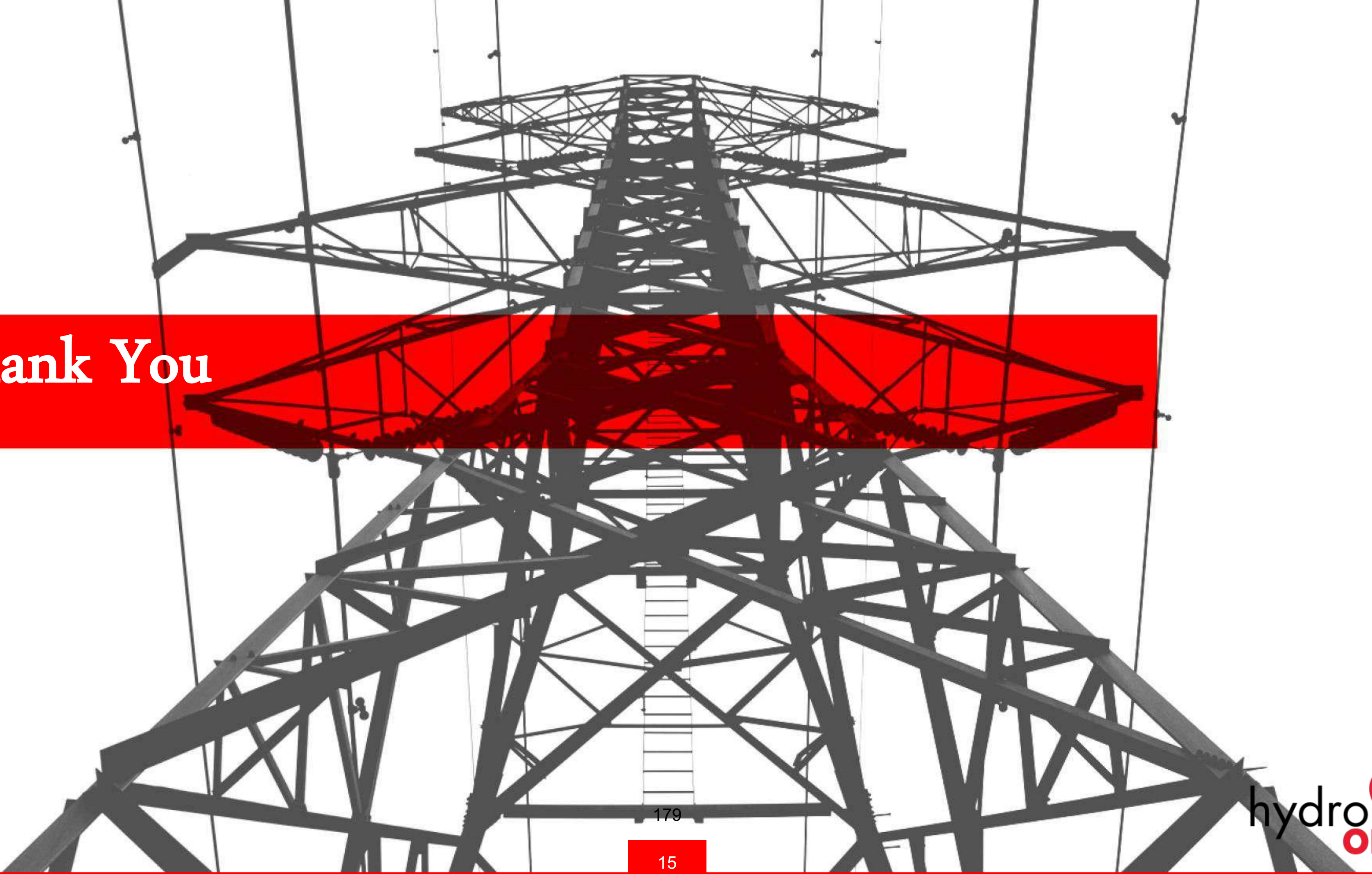
- Outage is executed in the Control Room
- IESO still provides day of approval
- IESO will contact Generators if there are requirements to change output of units
- Shift Controllers will contact customer prior to outage commencing
    - Critical that contact details for real time operations are available for Hydro One to contact
- If issues occur day of, contact your Real Time contact as per the connection agreement

TAKEAWAYS

- IESO dictates limits
  - Hydro One can advise of upcoming outages, IESO will provide direct details on maneuvering of units
- Attend the Customer Conferences
  - Allows your input into the outage plans
- Plan ahead and provide details to Hydro One as far ahead as possible
  - Opportunity to minimize outages
  - Opportunity to better bundle work
- Become familiar with your Planning Contacts



Questions?



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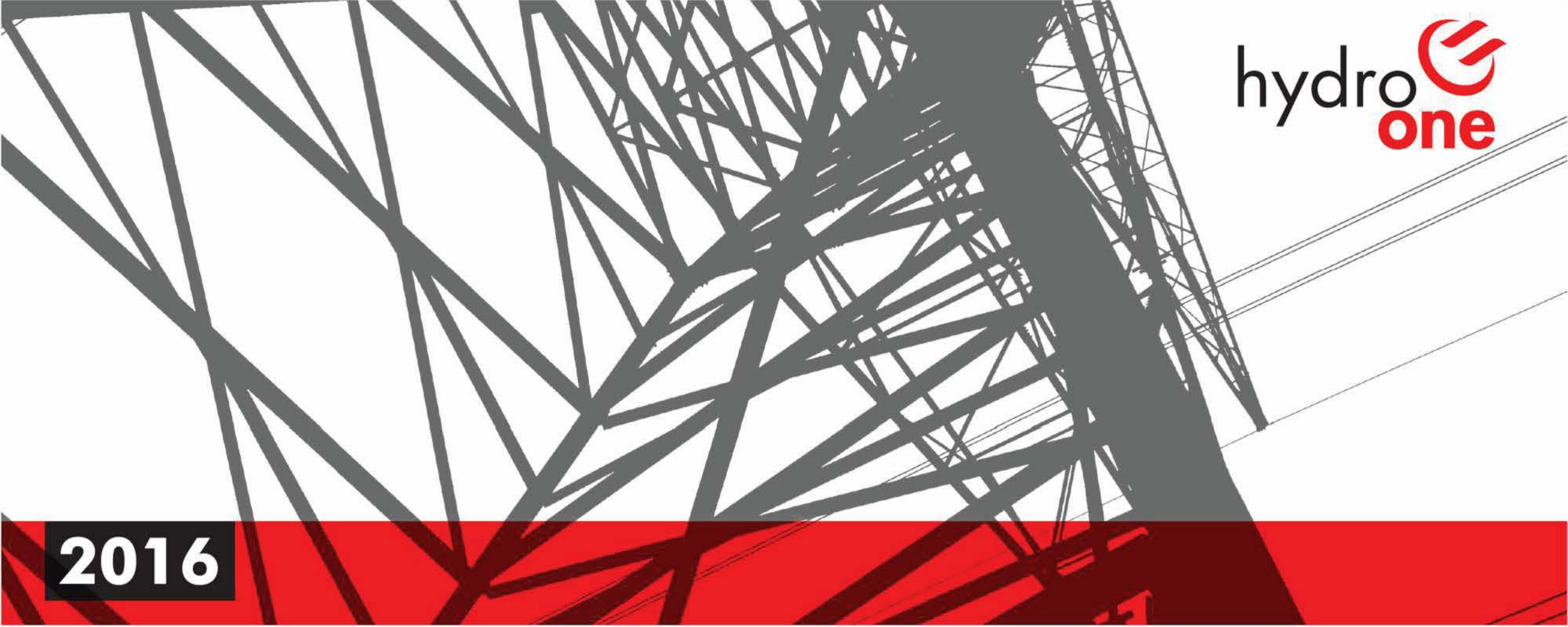
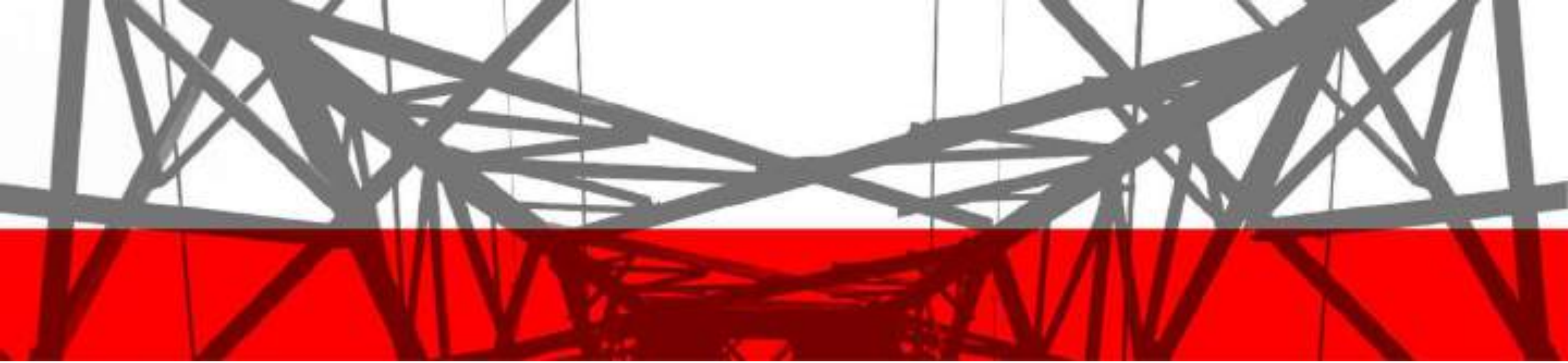


LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



BILLING & PAYMENT: LOAD DISPLACEMENT GENERATION, NET METERING AND ENERGY STORAGE

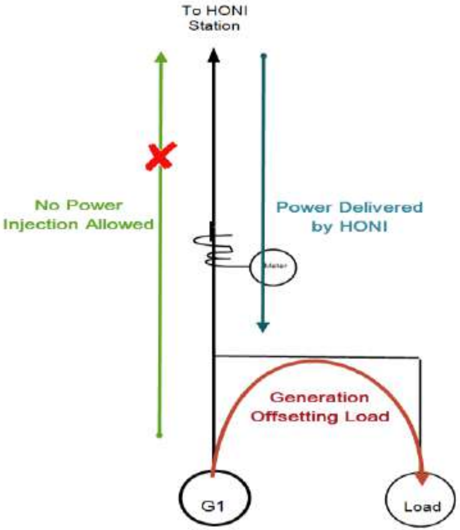
Jaspreet Nijjar

Settlement Supervisor

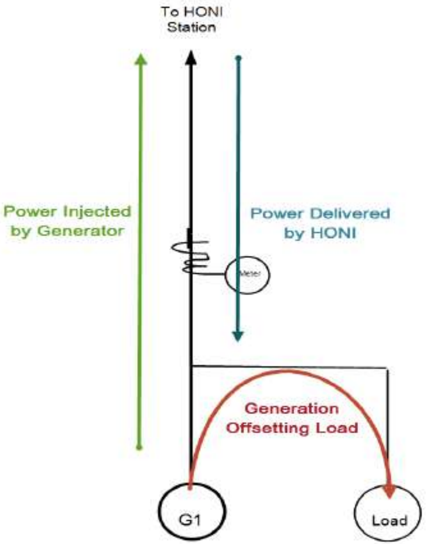
Transmission and Distribution Settlements

TYPE OF DISTRIBUTION CONNECTED GENERATORS

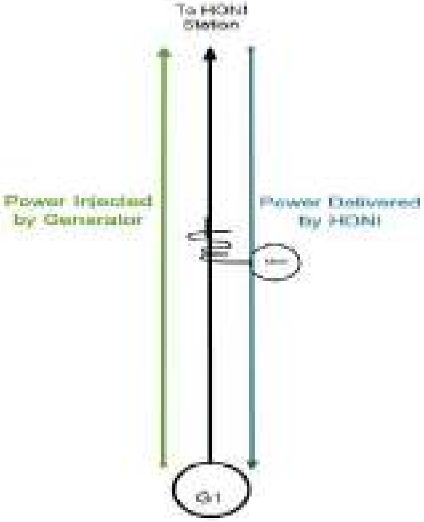
LOAD DISPLACEMENT



NET METERING



RETAIL GENERATOR



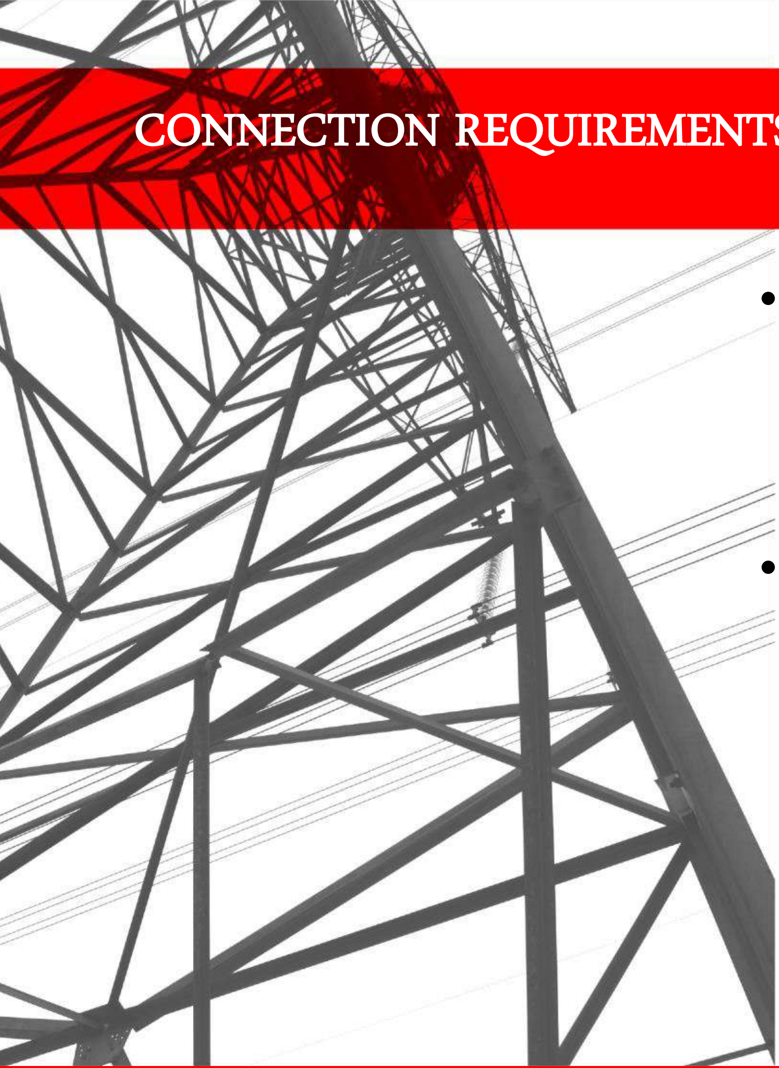
BILLING AND PAYMENT SCENARIOS FOR DIFFERENT TYPE OF DISTRIBUTION CONNECTED GENERATORS

Charge Type / Program Type	Billable Power	Payable Power Injection	Creditable Power Injection
LOAD DISPLACEMENT GENERATOR	(↓ Indicates Charges Offset)		
Commodity Charge (HOEP $/KWH)	YES ↓	NOT APPLICABLE	NOT APPLICABLE (No Injection Allowed)
Global Adjustment ($/MWH)	YES ↓		
Fixed Regulatory Charges ($)	YES		
Fixed Delivery Charges ($)	YES		
Variable Regulatory Charges ($/KWH)	YES ↓		
Variable Delivery Charges ($/KW or $/KWH)	YES ↓		
NET METERING GENERATOR	(↓ Indicates Charges Offset)		Roll Over Credits Over A Year Span
Commodity Charge (HOEP $/KWH)	YES ↓	NOT APPLICABLE	YES
Global Adjustment ($/MWH)	YES ↓		YES
Fixed Regulatory Charges ($)	YES		NO
Fixed Delivery Charges ($)	YES		NO
Variable Regulatory Charges ($/KWH)	YES ↓		YES
Variable Delivery Charges ($/KW or $/KWH)	YES ↓		YES ($/KWH), No ($/KW)
RETAIL GENERATOR			
Commodity Charge (HOEP $/KWH)	YES	YES	NOT APPLICABLE
Global Adjustment ($/MWH)	YES	NO	
Fixed Regulatory Charges ($)	YES	NOT APPLICABLE	
Fixed Delivery Charges ($)	YES	NOT APPLICABLE	
Variable Regulatory Charges ($/KWH)	YES	NOT APPLICABLE	
Variable Delivery Charges ($/KW or $/KWH)	YES	183 NOT APPLICABLE	

LOAD DISPLACEMENT GENERATION

- Load displacement generator and existing load have same owner
    - Please see Large Distribution Account (LDA) presentation

- Load displacement generator owner is different than existing load customer
    - Existing load customer will continue to be a customer of Hydro One
    - Hydro One is not a party in the agreement between load owner and load displacement generator owner



CONNECTION REQUIREMENTS

- A Customer Impact Assessment (CIA) is needed for installing any load displacement or back-up generator >10 kW as per Hydro One's Conditions of Service

- A Distribution Connection Agreement (DCA) must be executed for connecting any >10 kW generator

LOAD DISPLACEMENT IMPLICATIONS ON HYDRO ONE BILL

- A customer wants to reduce their electricity bill, in particular Global Adjustment
  - Class B customers want to reduce the total kWh based Global Adjustment charges
  - Class A customers want to avoid or reduce demand during the IESO system peaks to lower their Peak Demand Factor
  - Utilize waste heat from electricity generation

- Customer could be incented by IESO to install generator under Conservation Demand Management

- Customer needs to self declare Debt Retirement payment to Ministry of Finance
  - Current forecasted Debt Retirement Charge expiry is March 31, 2018

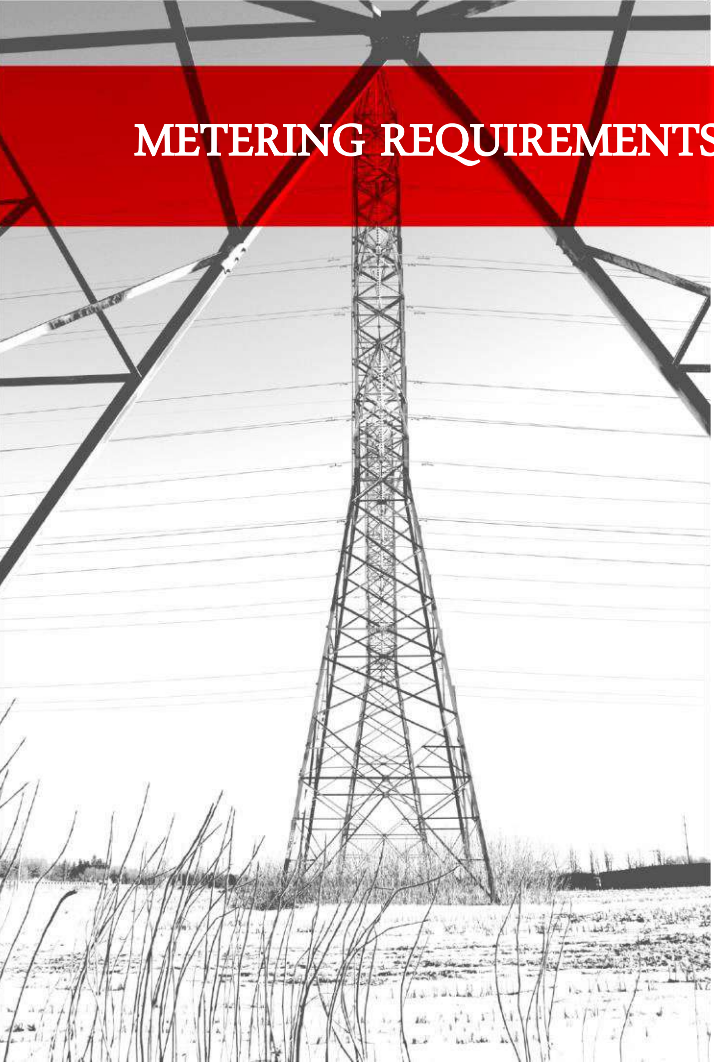
- Load Displacement generation may impact Class A qualification
  - Please consult Meghan Atkinson (Meghan.Atkinson@HydroOne.com) for more information

- Depending on type and size of the generator, customer may or may not attract Gross Loading Billing

POTENTIAL TRANSMISSION AND DISTRIBUTION CHARGES IMPLICATION FOR INSTALLING LOAD DISPLACEMENT GENERATOR

- Depending on the type and size per unit of the load displacement generator, it may trigger Gross Load Billing (GLB) of Transmission Line and Transformation Connection charges, but not Network charge
- Gross Load Billing applies to Distribution Common Sub-transmission Rate but not to the General Service Rates
- GLB thresholds: (1 MW for non-renewable and 2 MW for renewable) refer to unit capacity (in the case of solar, inverter capacity), not site capacity
  - Eg. A solar farm with 10 MW (20 x 0.5 MW inverter) capacity would not trigger GLB
- GLB also applies to the incremental capacity of a refurbished legacy generator
  - Eg. GLB applies to the 5 MW incremental capacity of a refurbished 7 MW Legacy generator with 2 MW old capacity

METERING REQUIREMENTS



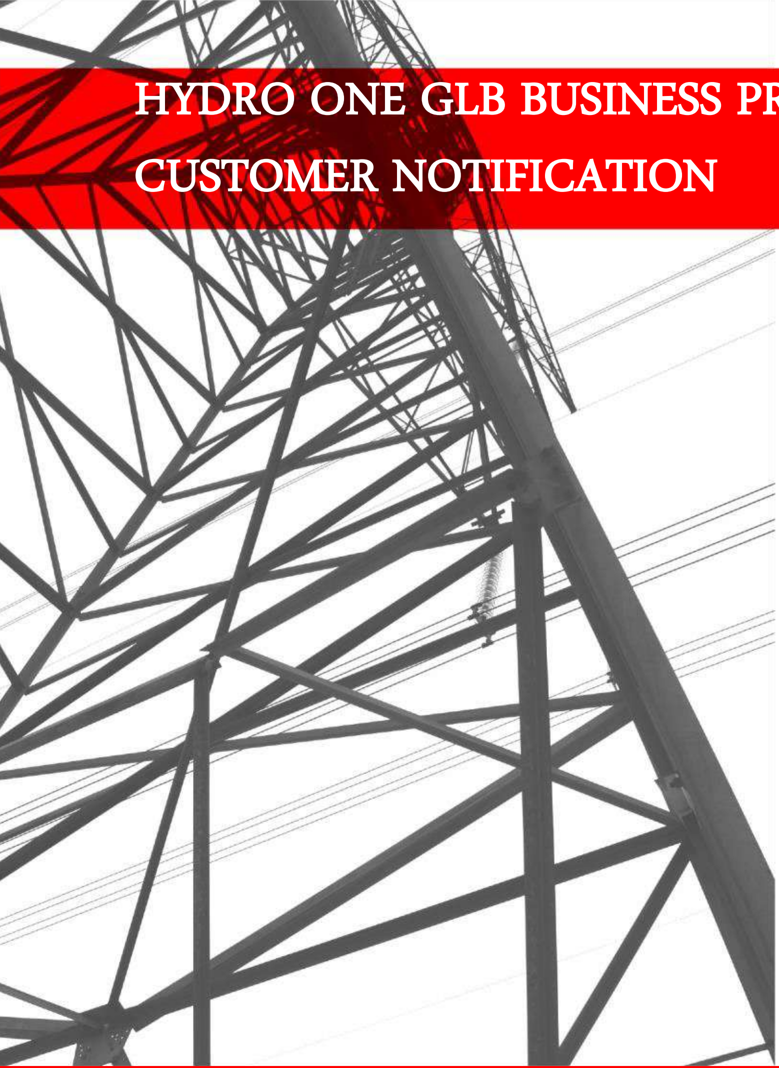
- Sub-transmission Customer
  - Hydro One will install a retail revenue meter to measure the generator’s output (only for sub-transmission customers) for gross load billing calculation
  - An additional meter charge will be applied
- General Service Demand Customer
  - Customer will need to install their own meter for Debt Retirement Charge declaration to the Ministry of Finance

GROSS LOAD BILLING FOR ISLANDING OPERATION WITH LOAD DISPLACEMENT GENERATOR

- A Customer with a load displacement generator operating off-grid is still subject to Gross Load Billing if they are connected to the grid for any back-up supply

- For complete off-grid operation, 365/7/24, Hydro One will not Gross Load Bill the customer but will remove all of the distribution assets from the connection and does not provide back-up support

HYDRO ONE GLB BUSINESS PROCESS – CUSTOMER NOTIFICATION



- Hydro One Connection Impact Assessment (CIA) process now includes GLB assessment for any generators with a size of 1MW or more, to make customers aware of GLB eligibility and the settlement impacts

UPCOMING POTENTIAL CHANGES

- OEB is initiating a policy review to address the question of how a commercial and industrial customers should be billed when they have a Load Displacement Generator (LDG) behind the meter

- http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/OEBltr_Gross_Load_Billing_Tx_20160329.pdf

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NET METERING – EXISTING FRAMEWORK

- Our Net Metering program is available to any Hydro One customer who generates electricity primarily for their own use from a renewable energy source (wind, water, solar radiation or agricultural biomass) using equipment with a total nameplate rating of **500 kW or less**

- Net metering allows you to send electricity generated from Renewable Energy Technologies (RETs) to Hydro One's distribution system for a credit towards your electricity costs
    - Excess generation credits can be carried forward for up to 11 months, including the 11th month, to offset future electricity costs

NET METERING – PROPOSED AMENDMENTS

- Remove the capacity limit of 500 kW
- Extend credit carry forward period from 11 months to 12 months
- Virtual Net Metering – credits transfer within multiple accounts, within the same LDC, within the distance requirement
  - Proposed: 3km
- Pairing of renewable energy sources with energy storage which allows for flexible injection

ENERGY STORAGE

- Energy Storage License is required by OEB
- Proponent is subject to the same Hydro One connection process for distribution generator
- Hydro One will settle Energy Storage as non-contract generator:
  - Bill all charges (delivery, energy and global adjustments) for energy withdrawn from the grid
  - Pay spot prices when injected energy
- Industry estimates 20% loss for kWh transaction – for every 100 kWh withdrawn, only 80 kWh injected back to the grid
- Potential Cost Mitigation if energy storage is allowed as stand alone source for Net Metering – injection will receive both global adjustment and energy credit

BILLING AND PAYMENT SCENARIOS FOR DIFFERENT TYPE OF DISTRIBUTION CONNECTED GENERATORS

Program Type \ Charge Type	Billable Power	Payable Power Injection	Creditable Power Injection
LOAD DISPLACEMENT GENERATOR	(↓ Indicates Charges Offset)		
Commodity Charge (HOEP $/KWH)	YES ↓	NOT APPLICABLE	NOT APPLICABLE (No Injection Allowed)
Global Adjustment ($/MWH)	YES ↓		
Fixed Regulatory Charges ($)	YES		
Fixed Delivery Charges ($)	YES		
Variable Regulatory Charges ($/KWH)	YES ↓		
Variable Delivery Charges ($/KW or $/KWH)	YES ↓		
NET METERING GENERATOR	(↓ Indicates Charges Offset)		Roll Over Credits Over A Year Span
Commodity Charge (HOEP $/KWH)	YES ↓	NOT APPLICABLE	YES
Global Adjustment ($/MWH)	YES ↓		YES
Fixed Regulatory Charges ($)	YES		NO
Fixed Delivery Charges ($)	YES		NO
Variable Regulatory Charges ($/KWH)	YES ↓		YES
Variable Delivery Charges ($/KW or $/KWH)	YES ↓		YES ($/KWH), No ($/KW)
RETAIL GENERATOR			
Commodity Charge (HOEP $/KWH)	YES	YES	NOT APPLICABLE
Global Adjustment ($/MWH)	YES	NO	
Fixed Regulatory Charges ($)	YES	NOT APPLICABLE	
Fixed Delivery Charges ($)	YES	NOT APPLICABLE	
Variable Regulatory Charges ($/KWH)	YES	NOT APPLICABLE	
Variable Delivery Charges ($/KW or $/KWH)	YES	NOT APPLICABLE	

COMMON QUESTIONS- EXPANSION DEPOSIT REFUNDS

- http://www.hydroone.com/Generators/Pages/ExpansionDepositRefunds.aspx
- Capital contribution towards expansion projects is referred as ‘Expansion Deposit’
- Hydro One shall perform an annually assessment and return the percentage of expansion deposit in proportion to the actual demand
  - Assessment performed after the first anniversary and second anniversary date from letter of authorization to generate date (milestone #3)

$$\textit{Refund Percentage}\ \% = \frac{\textit{Actual Demand}}{\textit{Forecasted Demand}} \times 100\%$$

- If expansion deposit is in the form of cash, expansion deposit refund amount is determined by:

$$\textit{Expansion Deposit Refund Amount} = \textit{Refund Percentage} \times \textit{Expansion Deposit on File(Incl.HST)} + \textit{Accumulated Interest}$$

COMMON QUESTIONS – PAYMENT SETOFFS

- Project cost true up/true down
- Avoid cross subsidization for capital cost expenditure
- Hydro One Conditions of Service: "**K.3 Distributors right to deduct**"
- Please contact your Account Executive as soon as possible for capital cost disputes

COMMON QUESTIONS – OPERATIONAL ISSUES

- Over-generation: Hydro One distribution connection agreement (DCA) describes maximum kW capacity allocated to the generator
- System availability: No re-imbursement for outages
- Metering issues: Hydro One takes over meter ownership after installation:
    - Limited stock due to cost: Typical PMU cost for 10 MW unit:
        - 44 kV: approximately $32 k to $35K
        - 27 kV: approximately $22 or $25K
- Manufacturing and regulatory delays
- Billing inquires: HydroOneBCC@HydroOne.com
- Other issues: Account Executive

COMMON QUESTIONS – PAYMENTS

- MyAccount: Review current and historical generation payment statements

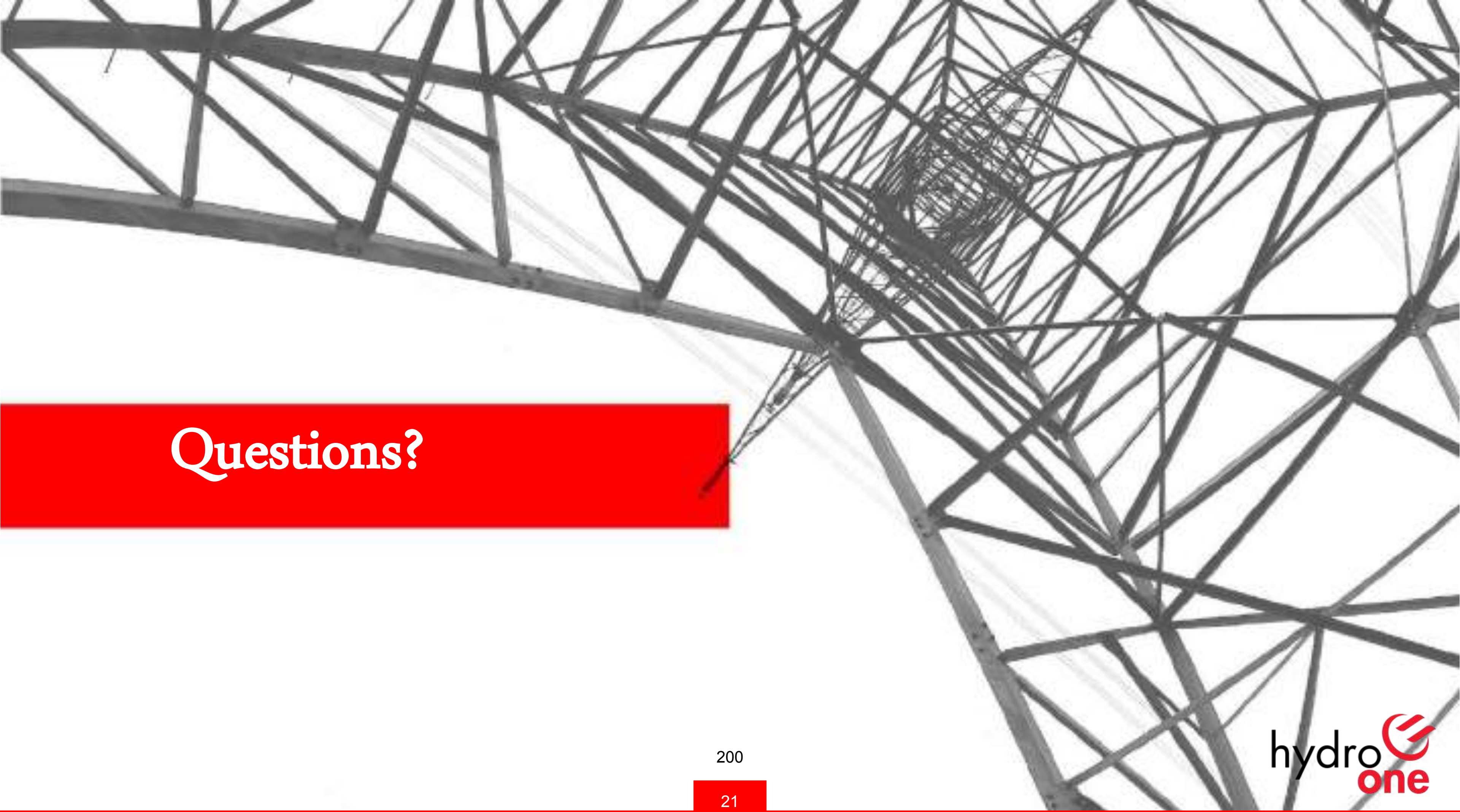
  http://www.hydroone.com/MyHome/MyAccount/Manage/Pages/home.aspx

- View my hourly interval meter data:

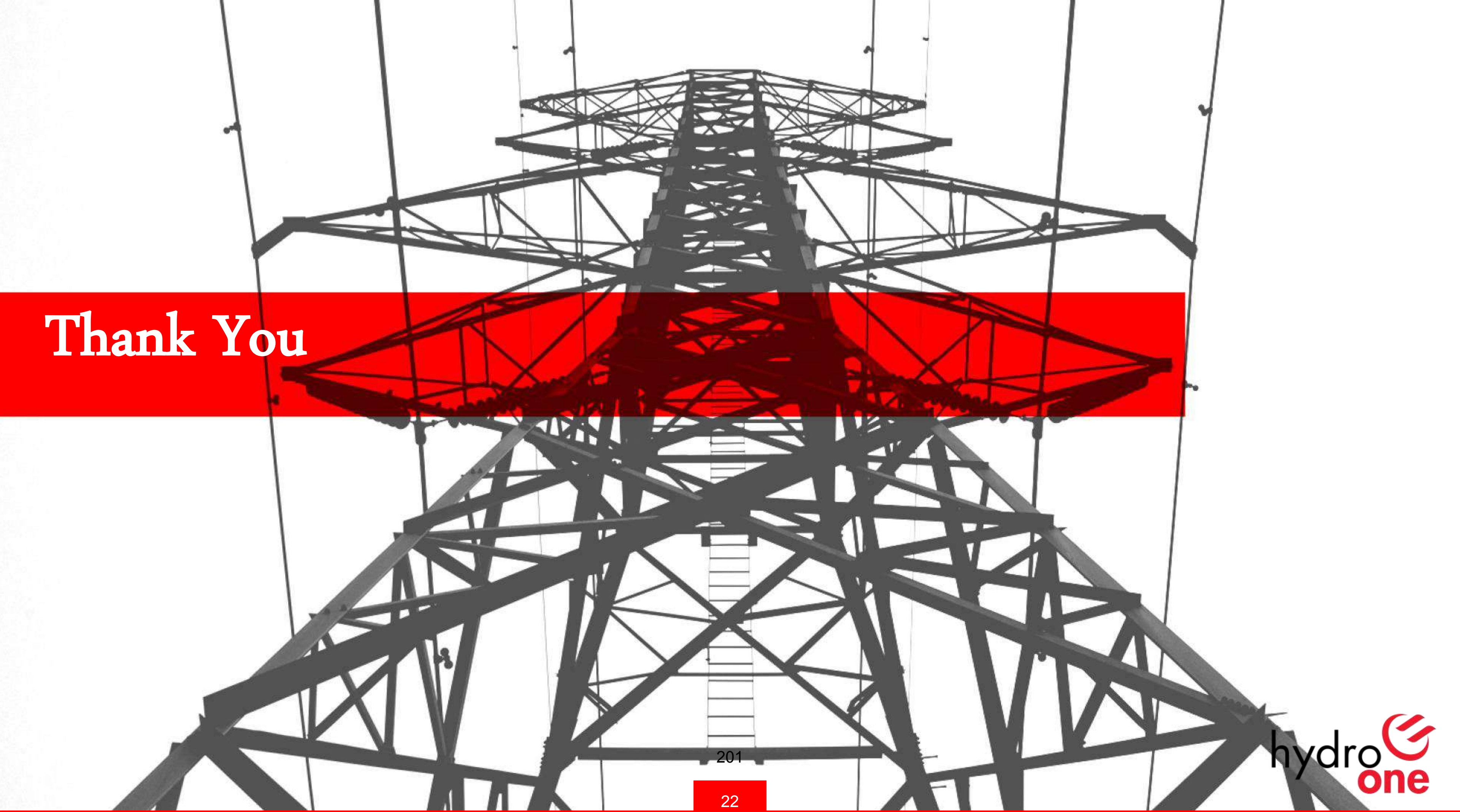
  https://www.elogin.hydroone.com/selfserv/fcs/main.jsp

- Questions: Hydro One BCC (Business Customer Center)

- Phone: 1-866-922-2466 or Email: hydroonebcc@hydroone.com



Questions?



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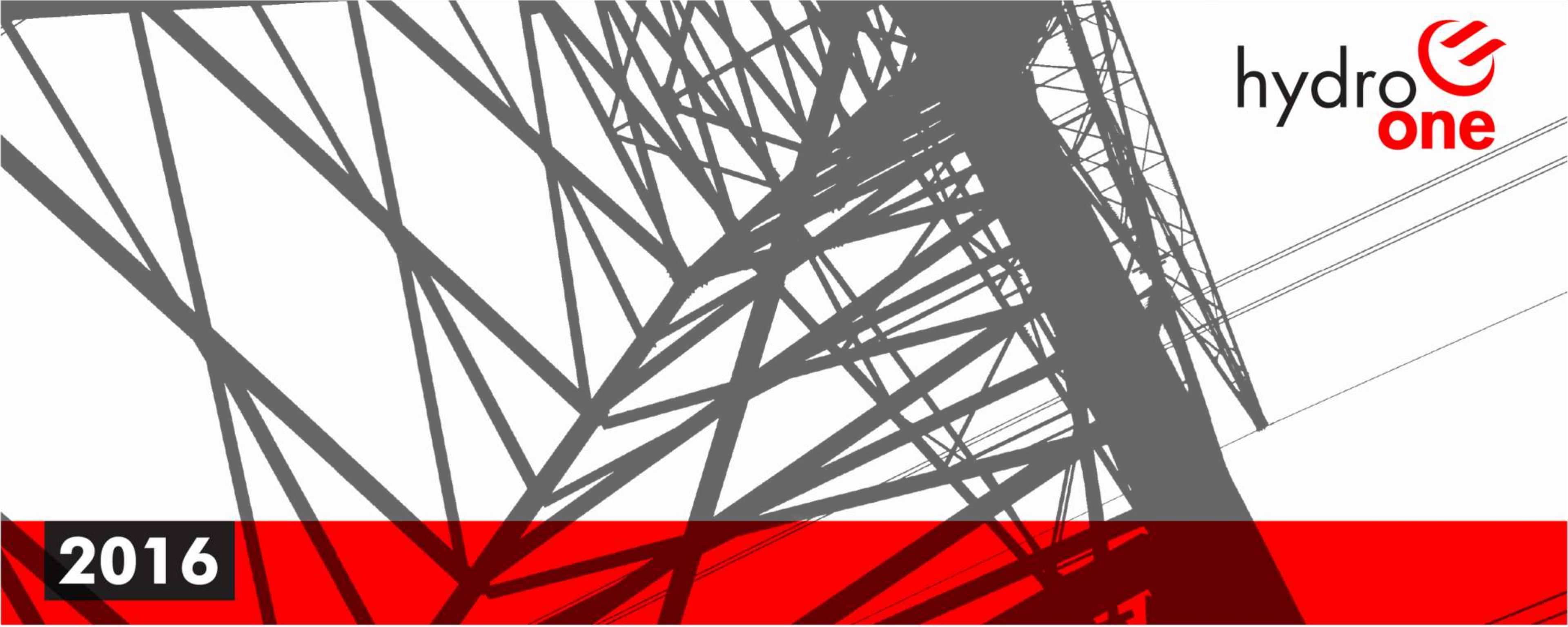
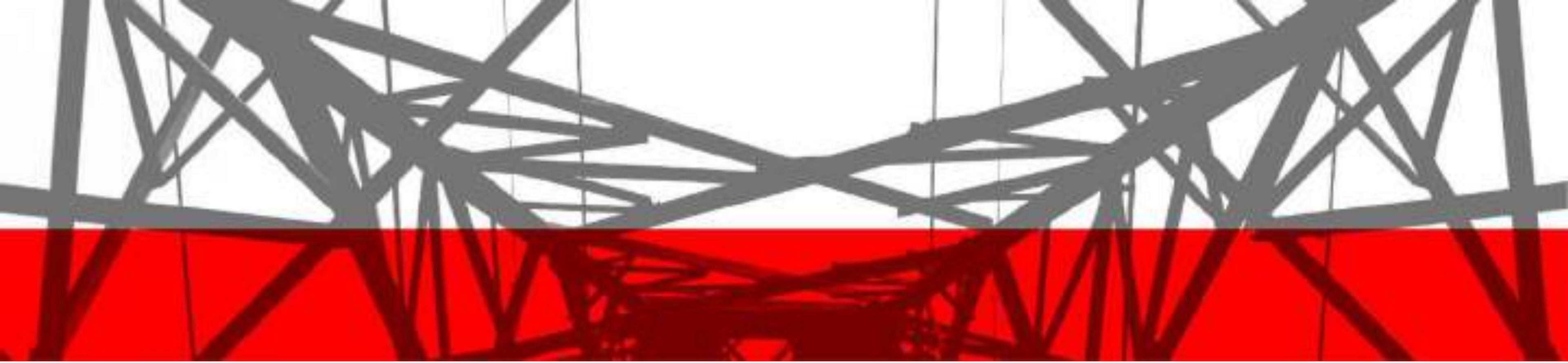


LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



BILLING & PAYMENT: LOAD DISPLACEMENT GENERATION, NET METERING

Jaspreet Nijjar

Settlement Supervisor

Transmission and Distribution Settlements

LOAD DISPLACEMENT GENERATOR

Rationale for installing Load Displacement Generator:

- A customer wants to reduce their electricity bill, in particular Global Adjustment
  - Class B customers want to reduce the total kWh based Global Adjustment charges
  - Class A customers want to avoid or reduce demand during the IESO system peaks to lower their Peak Demand Factor
- Customer could be incented by IESO to install generator under Conservation Demand Management

Load Displacement Generator impact:

- IESO performs settlement for transmission connected customers
- Customer needs to self declare Debt Retirement payment to Ministry of Finance
  - Current forecasted Debt Retirement Charge expiry is March 31, 2018
- Load Displacement generation may impact Class A qualification
  - Please consult IESO
- Customers with a load displacement generator cannot backfeed into the grid
- Depending on type and size of the generator:
  - CCRA true-up might be impacted
  - Or customer may not avoid certain delivery charges in their monthly bill

DISTRIBUTION GENERATION LOAD ADJUSTMENT GUIDELINES FOR CCRA TRUE UPS

Transmission System Code Section 6.5.9

When carrying out a true-up calculation for a load customer other than a distributor, a transmitter:

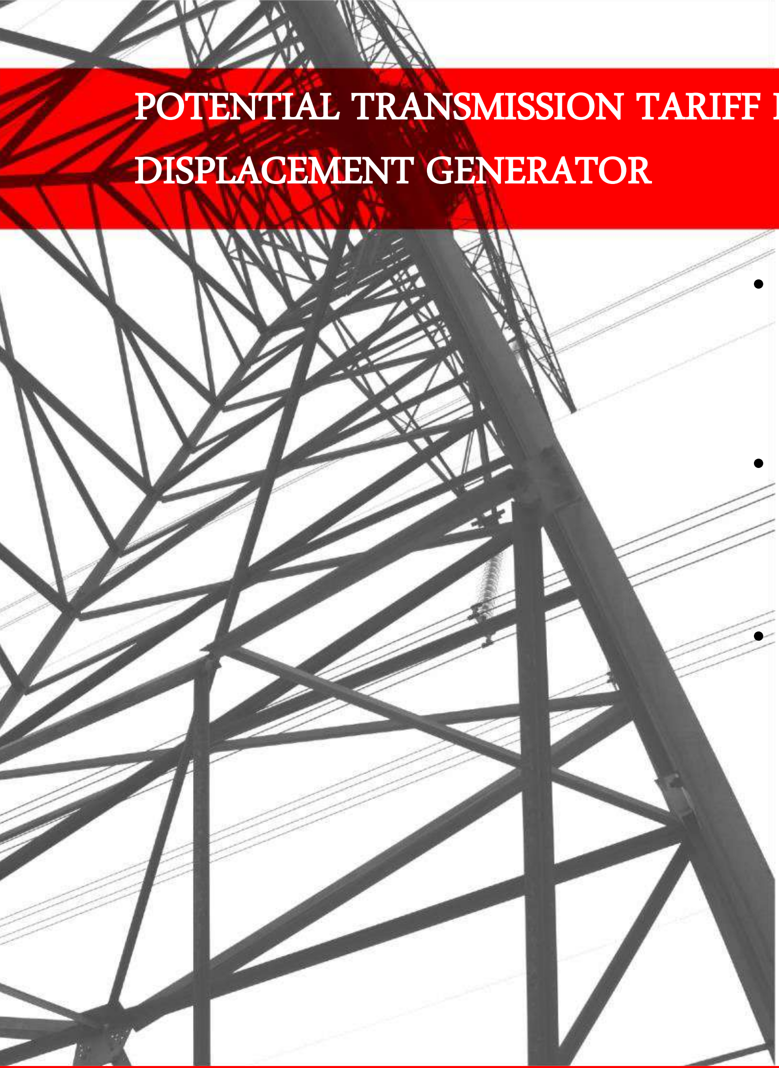
a) *shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period; and*

b) *shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1) of 1MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period*

http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Pages/Getting-Started-2.aspx

hydro one

POTENTIAL TRANSMISSION TARIFF IMPLICATION FOR INSTALLING LOAD DISPLACEMENT GENERATOR



- Depending on the type and size per unit of the load displacement generator, it may trigger Gross Load Billing (GLB) of Transmission Line and Transformation Connection charges, but not Network charge

- GLB thresholds (1 MW for non-renewable and 2 MW for renewable) refer to unit capacity (in the case of solar, inverter capacity), not site capacity
  - Eg. A solar farm with 10 MW (20 x 0.5 MW inverter) capacity would not trigger GLB

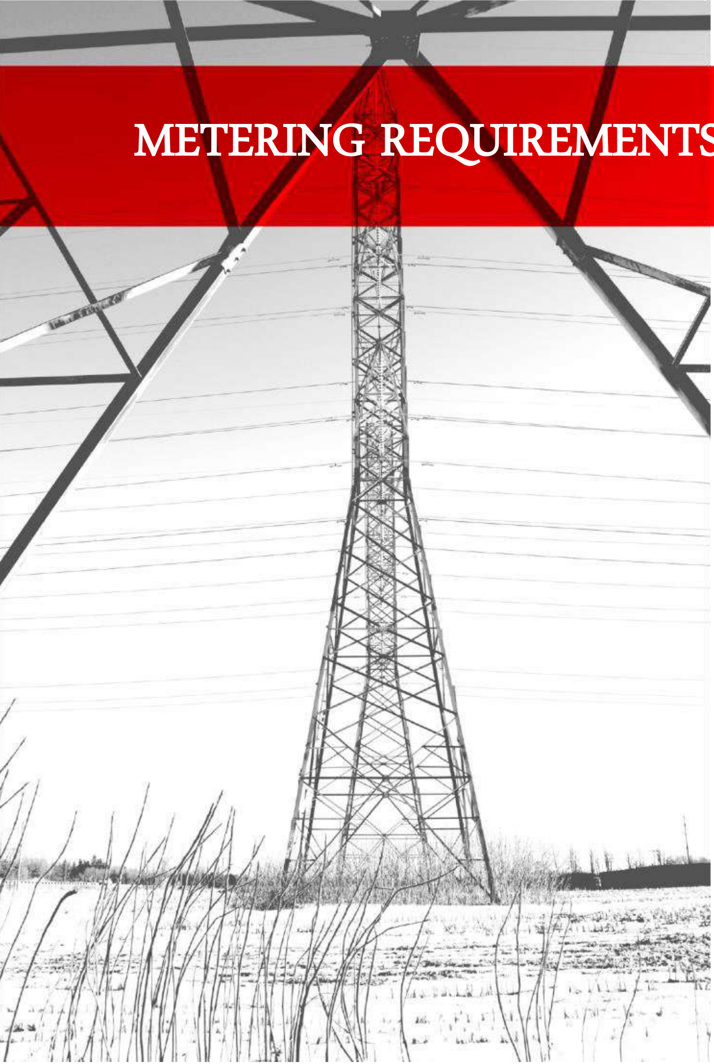
- GLB also applies to the incremental capacity of a refurbished legacy generator
  - Eg. GLB applies to the 5 MW incremental capacity of a refurbished 7 MW Legacy generator with 2 MW old capacity

GROSS LOAD BILLING REFERENCE IN ONTARIO UNIVERSAL TRANSMISSION RATE SCHEDULE

The following, in the OEB approved Ontario Universal Transmission Rate Schedule, authorizes Gross Load Billing of Transmission Line and Transformation Connection Charges:

The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2014-0357/Rate%20Order_%202015%20UTR_20150108.pdf



METERING REQUIREMENTS

Section 4.5

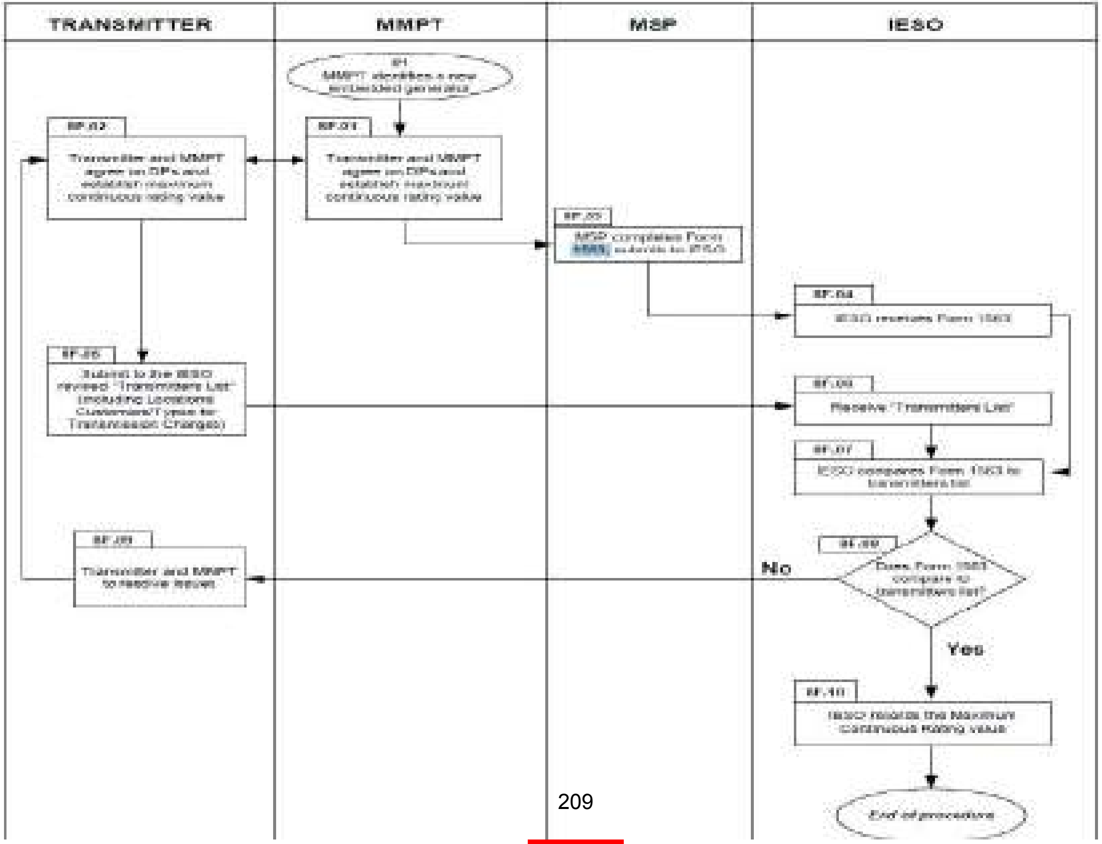
- Install and include wholesale revenue meter in totalization table

OR

- Submit form IMO-FORM-1563
    - GLB adjustment performed on annual basis

http://www.ieso.ca/Documents/marketRules/mr_chapter6.pdf

IESO Gross Load Billing Embedded Generator Reporting Process



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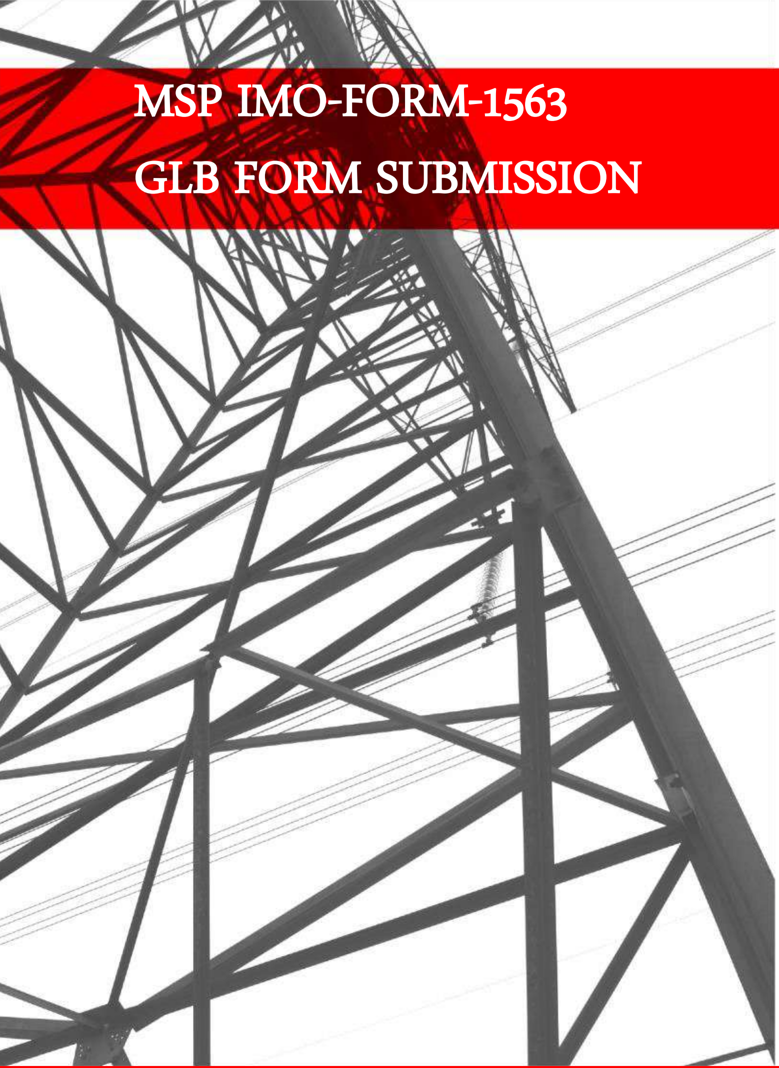


MSP IMO-FORM-1563
GLB FORM SUBMISSION

- Hydro One is receiving a large number of transmitter list rejections from IESO due to IMO-FORM-1563 and transmitter list mismatch

- Request MMPTs/MSPs to confirm generator name, maximum continuous rating, and generation start dates with transmitter prior to IESO submission

- Request MSPs to CC transmitter (TxDx.HydroOne@HydroOne.com) when MSPs send form IMO-FORM-1563 email to IESO

NO GROSS LOAD BILLING FOR EMERGENCY BACKUP GENERATOR

- GLB does not apply to emergency backup generator
  https://www.ontario.ca/laws/regulation/r07516

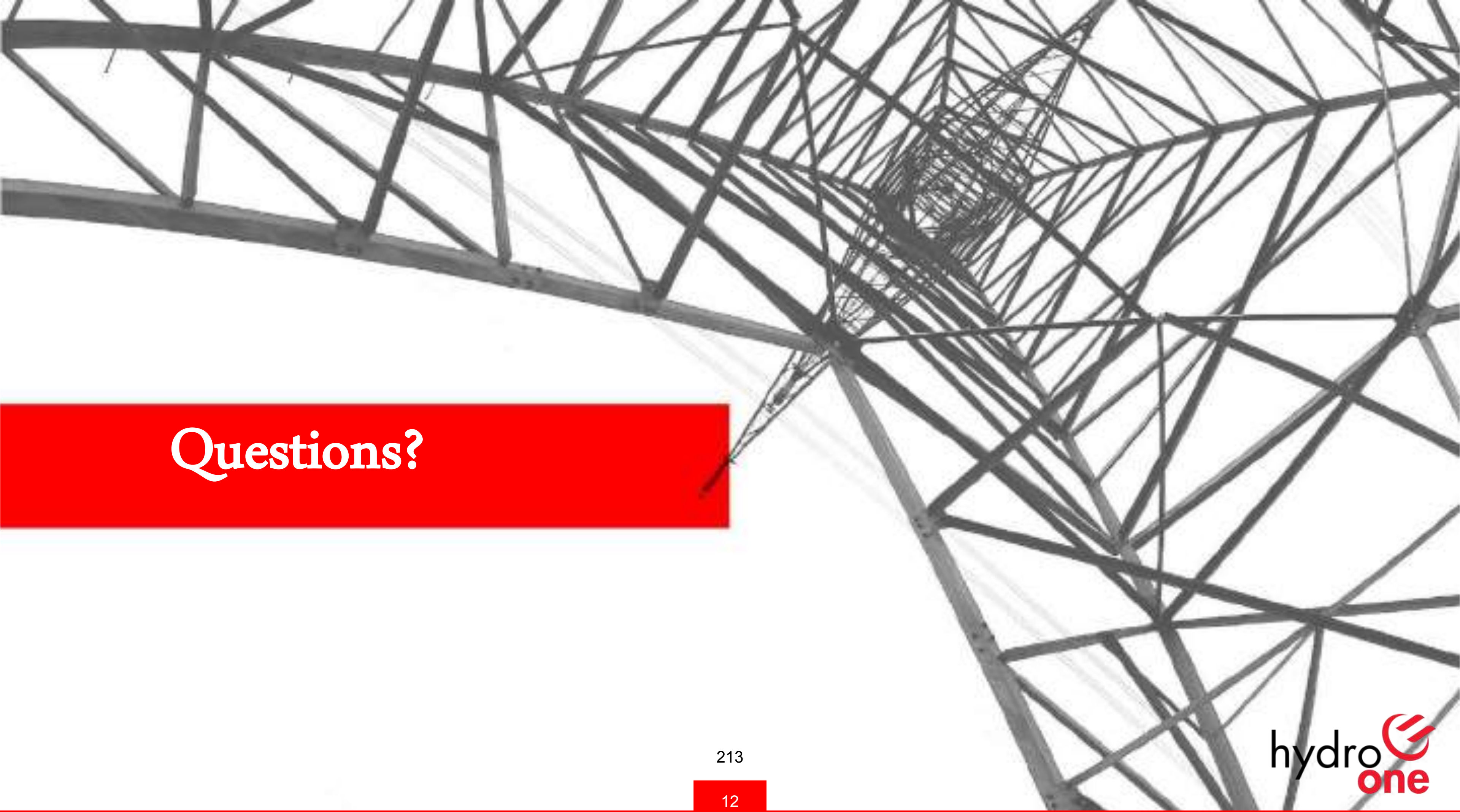
- "Standby power source" means equipment that is intended to be used for the purpose of producing power to maintain operating conditions when the power produced by the normal sources of power is cut off or reduced

CUSTOMER IMPACT ASSESSMENT (CIA) FOR INSTALLING LOAD DISPLACEMENT GENERATOR

- CIA is needed for installing load displacement generator
- Transmission Connected Customer Small Embedded Generation Assessment (TCCSEGA) can be used only for Transmission Embedded Generators that are 10 MW or less
    - This study should typically takes 90 calendar days
- Customer generating station (CGS) vs Customer transmission station (CTS).
- Key Account Management

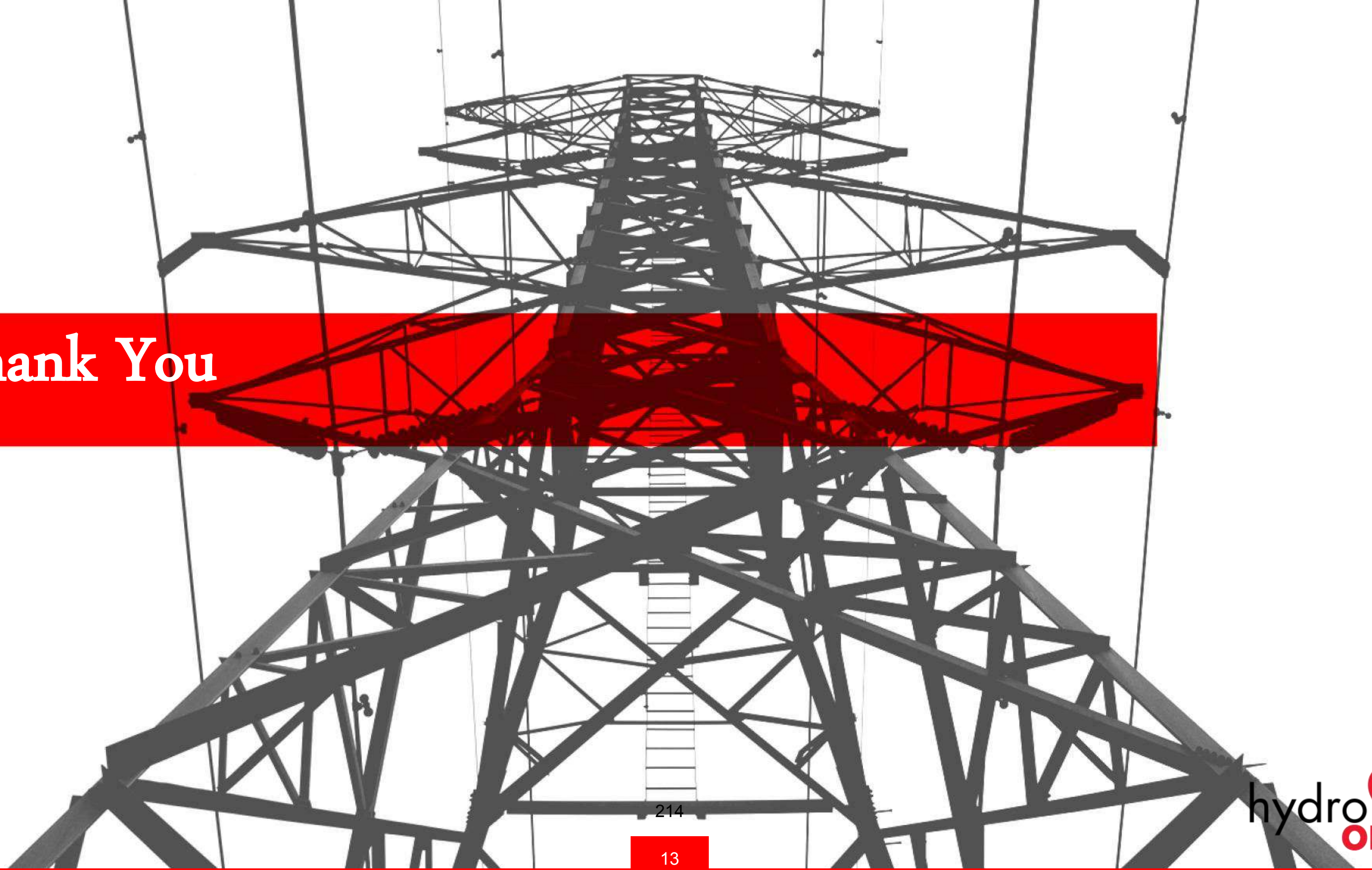
Hydro One Networks Inc.
483 Bay Street, 13th Floor, North Tower
Toronto, Ontario M5G 2P5
largeaccounts@HydroOne.com

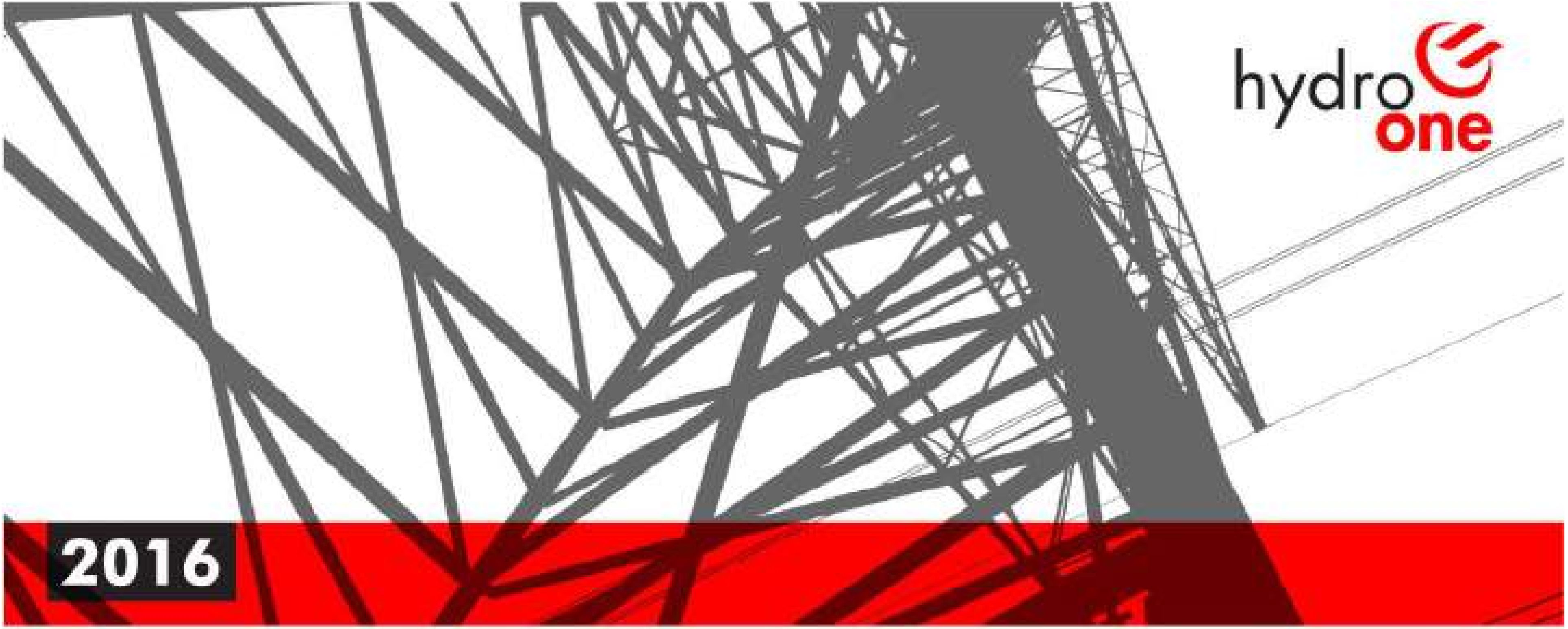
http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Pages/Getting-Started-2.aspx



Questions?

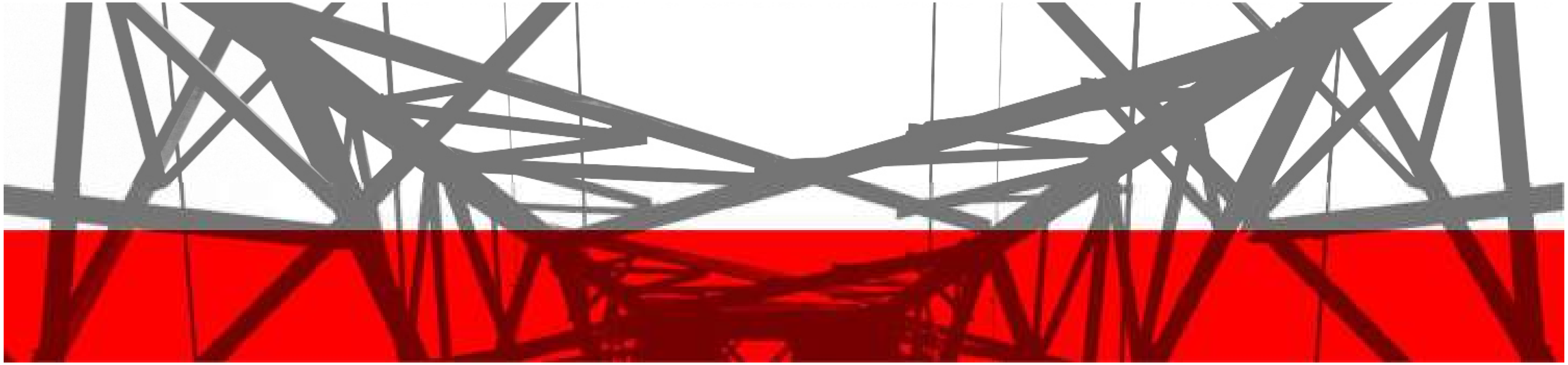
Thank You





LARGE CUSTOMER CONFERENCE

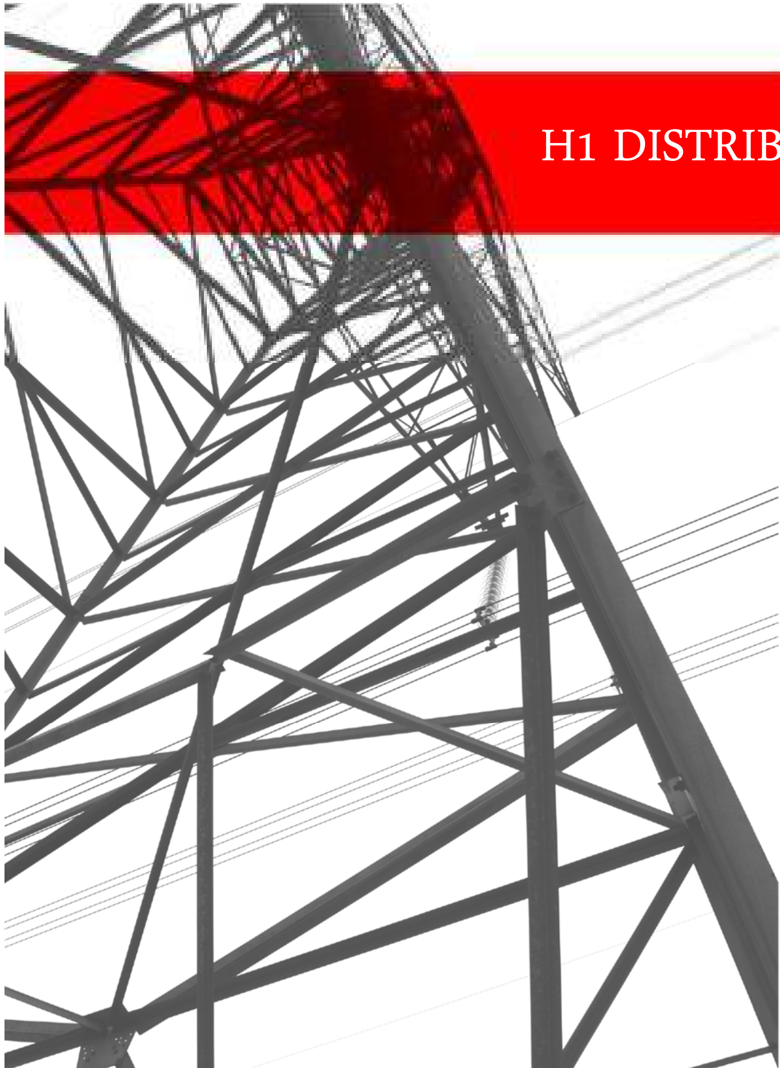
Productivity & Operational Efficiency



DISTRIBUTION OPERATIONS

James McGowan

Network Management Officer, Hydro One



H1 DISTRIBUTION CHALLENGES

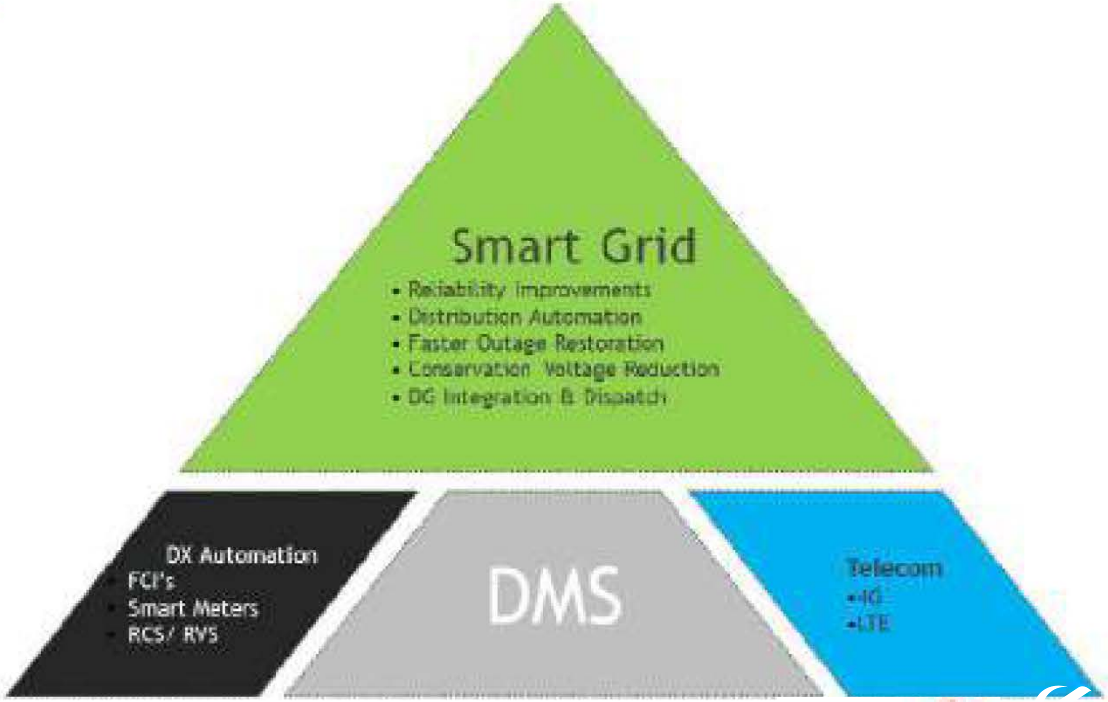
Very Long Rural & Radial Feeders

- Feeder Protections with Renewable Energy
- Outage Duration (SAIDI)
- Feeder transferability – limited by voltage support

Reactive Distribution Operating

- No Real-time DX operating diagrams
- Smart Meter data not leveraged
- No integration with field tablets and OMS

FOUNDATION OF SMART GRID



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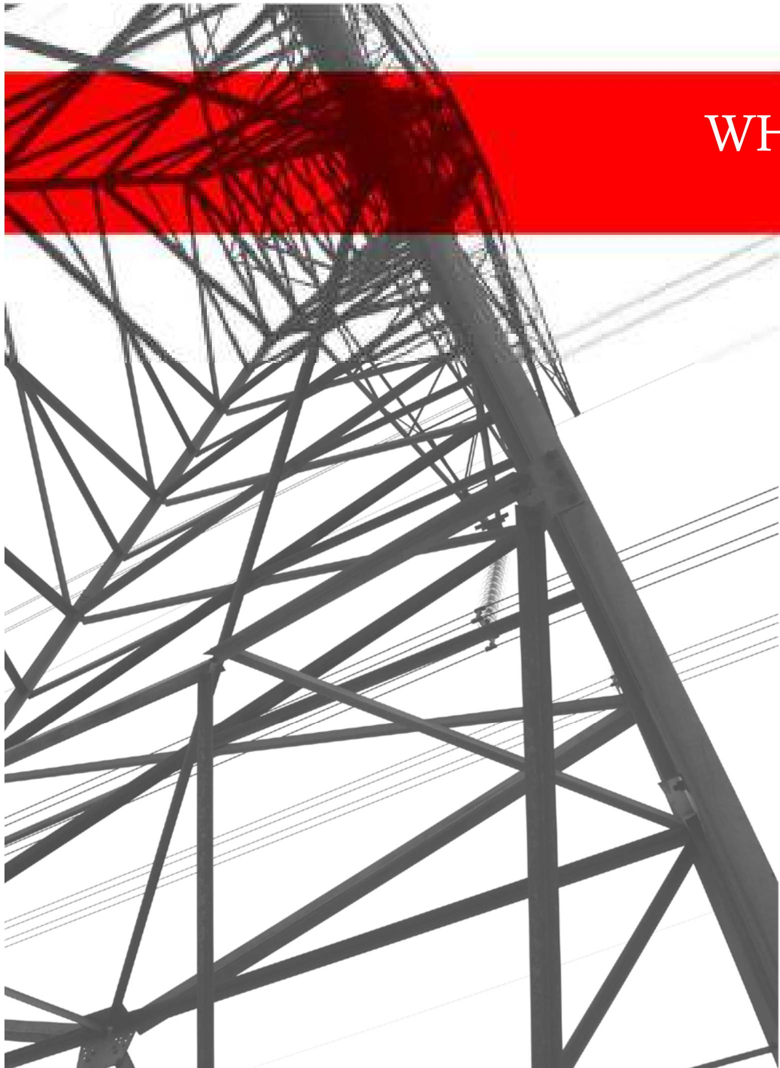

WHAT IS A DMS?

A decision support system to assist the Hydro One Control Centre and field staff with the monitoring and control of Hydro Ones electric distribution system.

It is the ***brain*** of our Smart Grid Solution!

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UNPLANNED OUTAGE SCENARIO

Lets discuss how we get the lights back on!

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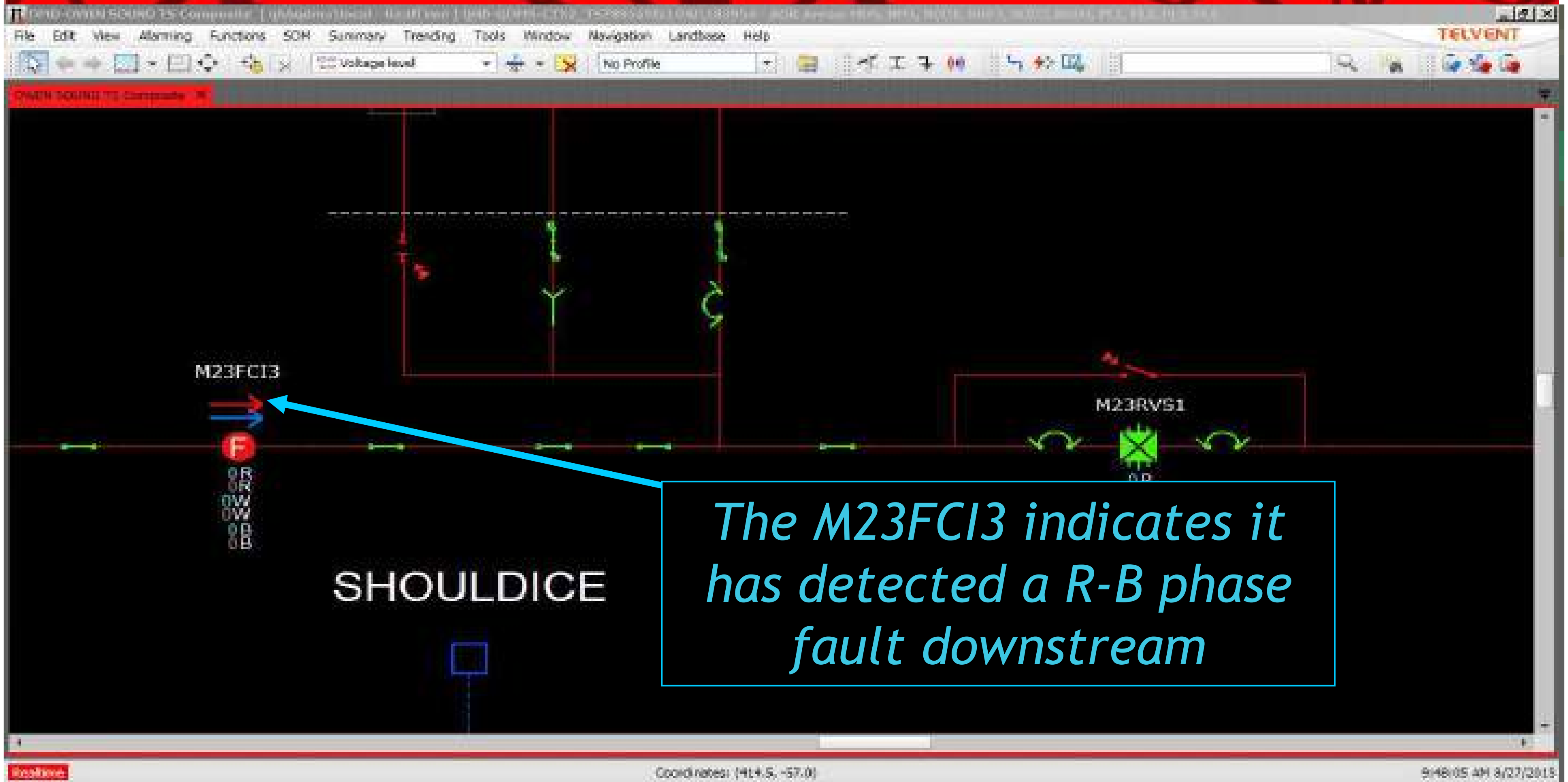
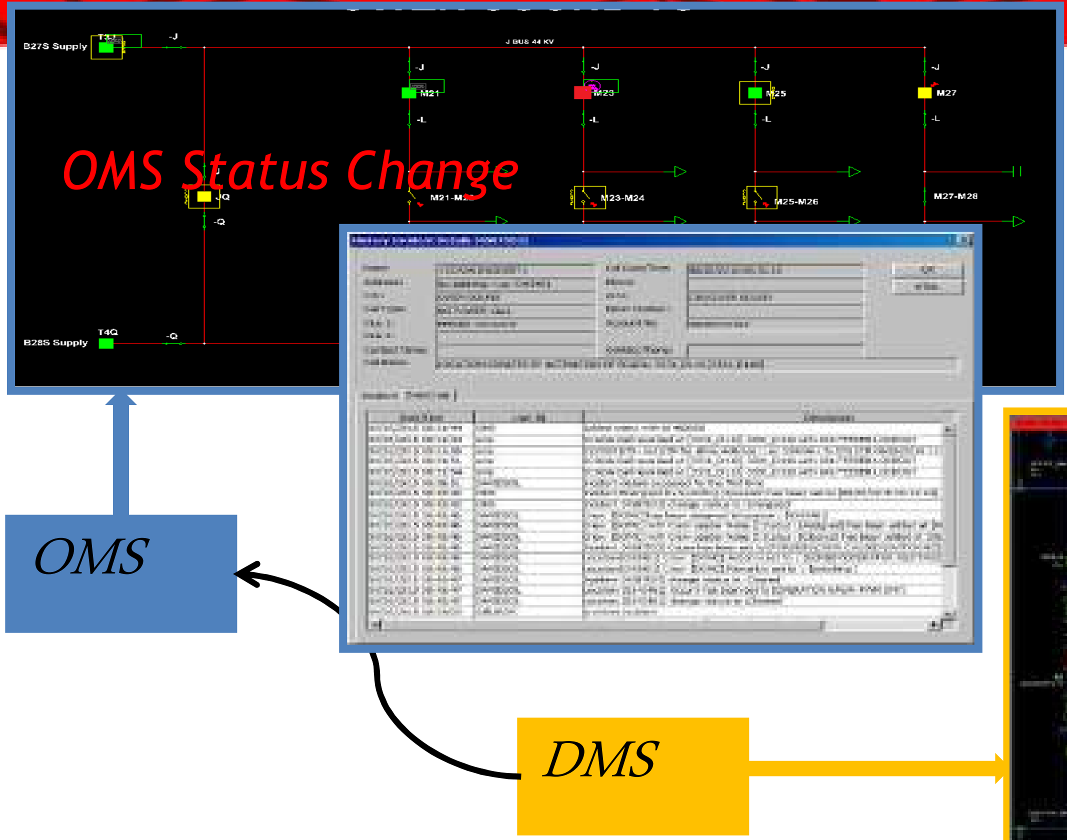
DMS OPERATOR #1- FEEDER TRIP ALARM

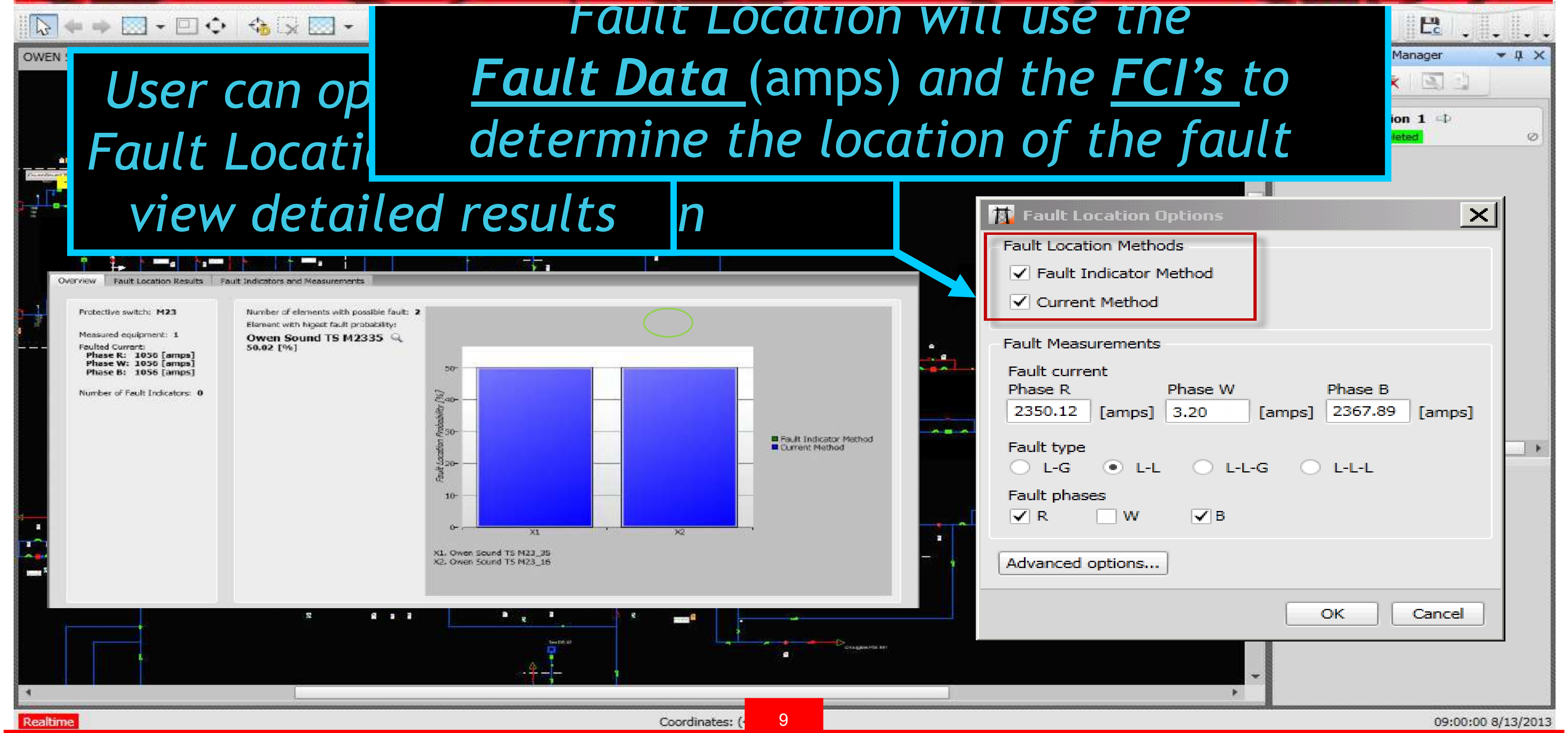


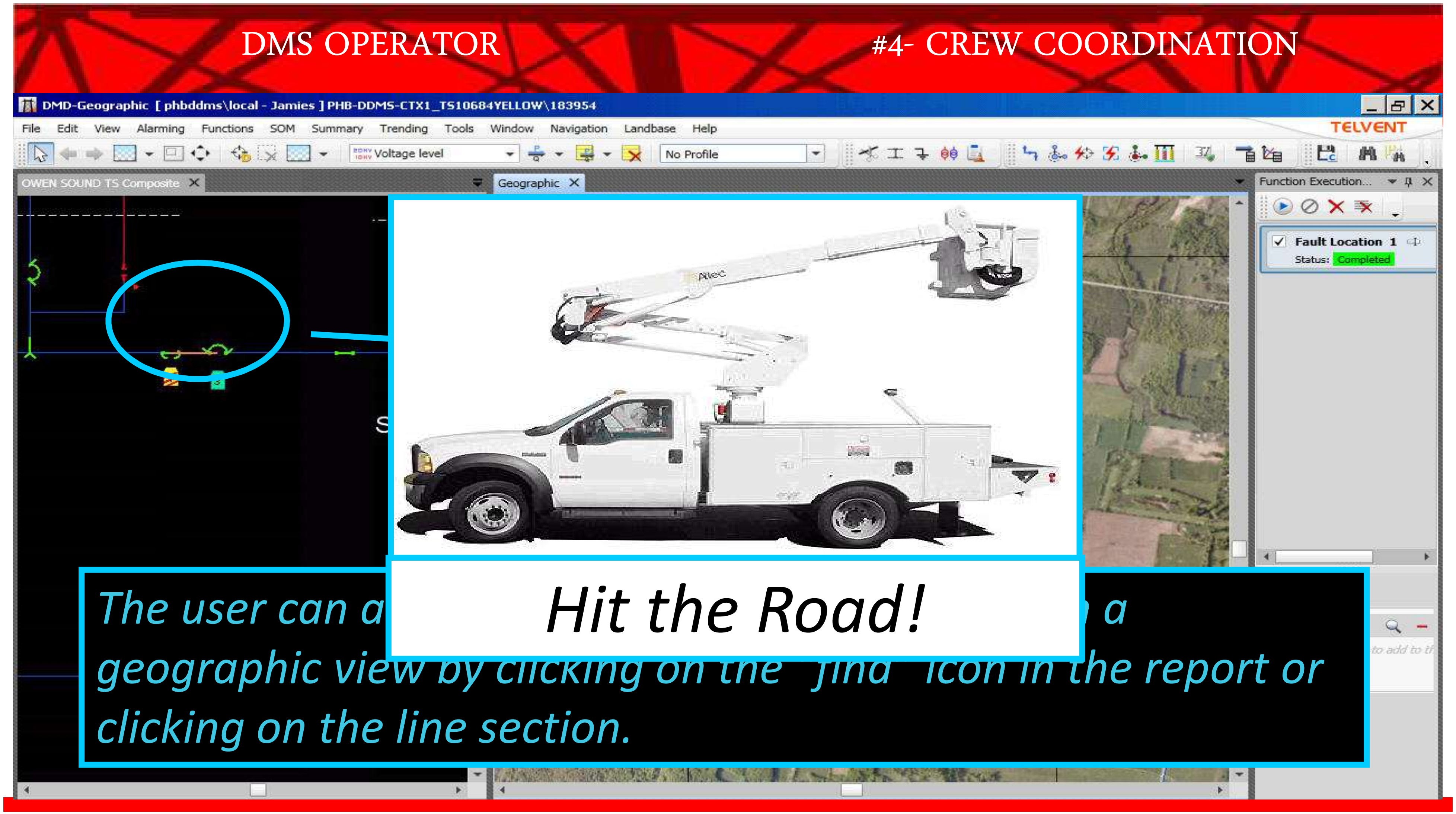
The M23FCI3 indicates it has detected a R-B phase fault downstream

DMS OPERATOR #2 - STATUS EXCHANGE

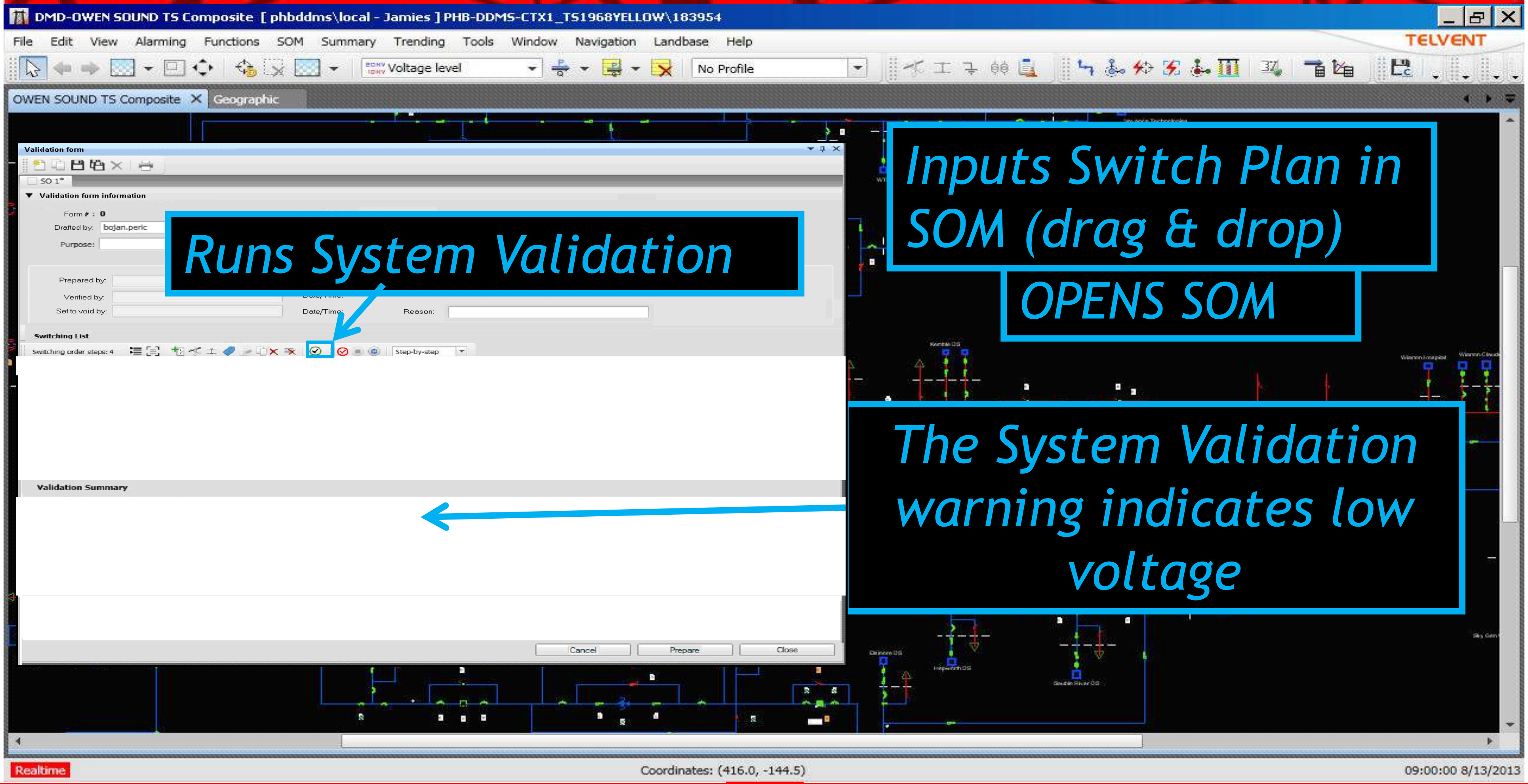


When the DMS Breaker status changes, a status change signal is sent to the Outage Management System via ICCP.

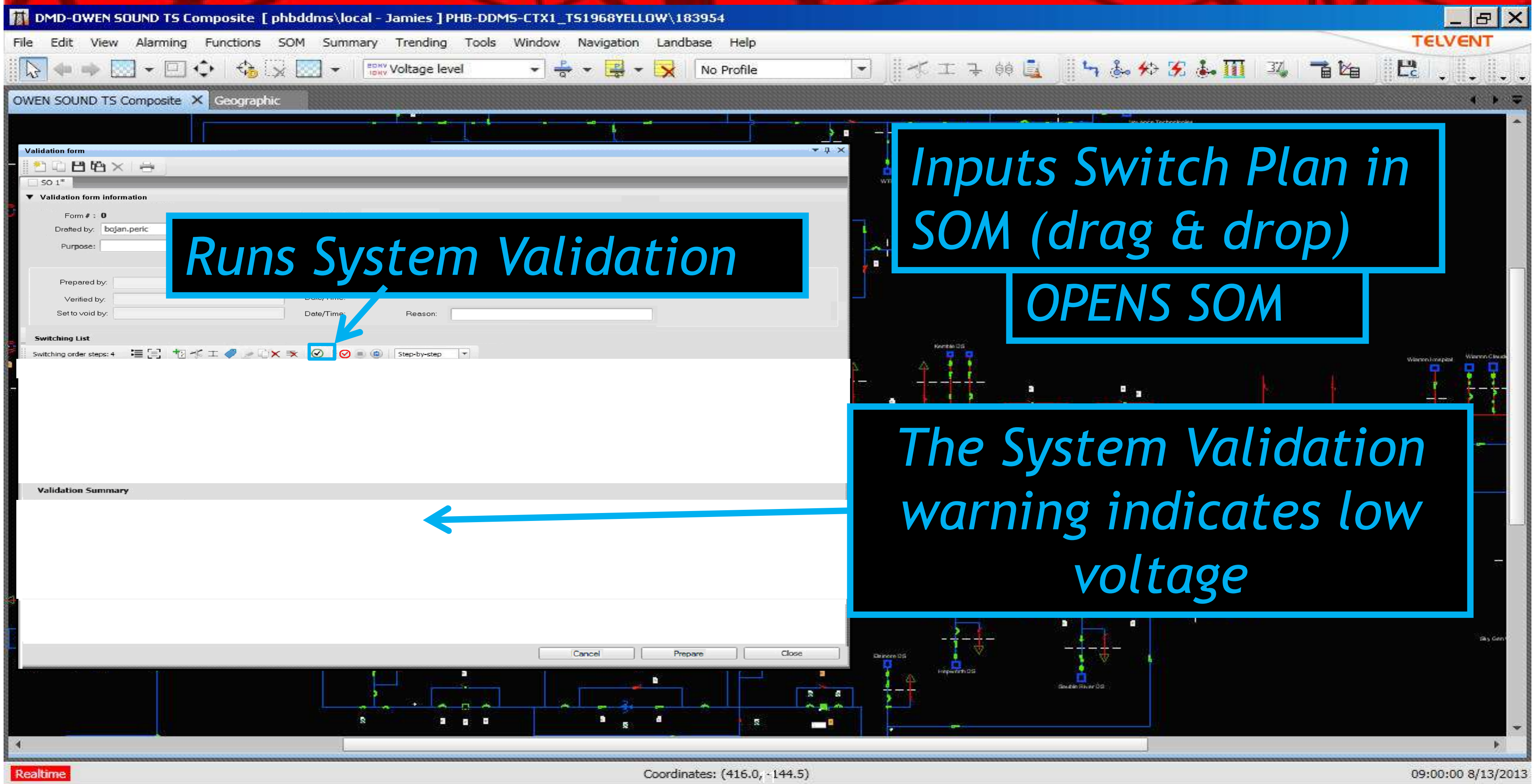

Fault Location will use the
Fault Data (amps) and the FCI's to
determine the location of the fault
User can op
Fault Locati
view detailed results
n
Fault Location Options
Fault Location Methods
Fault Indicator Method
Current Method
Fault Measurements
Fault current
Phase R
Phase W
Phase B
2350.12 [amps]
3.20 [amps]
2367.89 [amps]
Fault type
L-G
L-L
L-L-G
L-L-L
Fault phases
R
W
B
Advanced options...
OK
Cancel
Overview
Fault Location Results
Fault Indicators and Measurements
Protective switch: M23
Measured equipment: 1
Faulted Current:
Phase R: 1056 [amps]
Phase W: 1056 [amps]
Phase B: 1056 [amps]
Number of Fault Indicators: 0
Number of elements with possible fault: 2
Element with higest fault probability:
Owen Sound TS M2335
50.02 [%]
Fault Indicator Method
Current Method
X1. Owen Sound TS M23_35
X2. Owen Sound TS M23_16
Realtime
Coordinates:
09:00:00 8/13/2013


DMS OPERATOR
#4- CREW COORDINATION
DMD-Geographic [phbddms\local - Jamies] PHB-DDMS-CTX1_TS10684YELLOW\183954
File Edit View Alarming Functions SOM Summary Trending Tools Window Navigation Landbase Help
TELVENT
Voltage level
No Profile
OWEN SOUND TS Composite
Geographic
Function Execution...
Fault Location 1
Status: Completed
Altec
Hit the Road!
The user can a
a
geographic view by clicking on the
icon in the report or
clicking on the line section.

DMS OPERATOR #5- PROACTIVE PLANNING 28

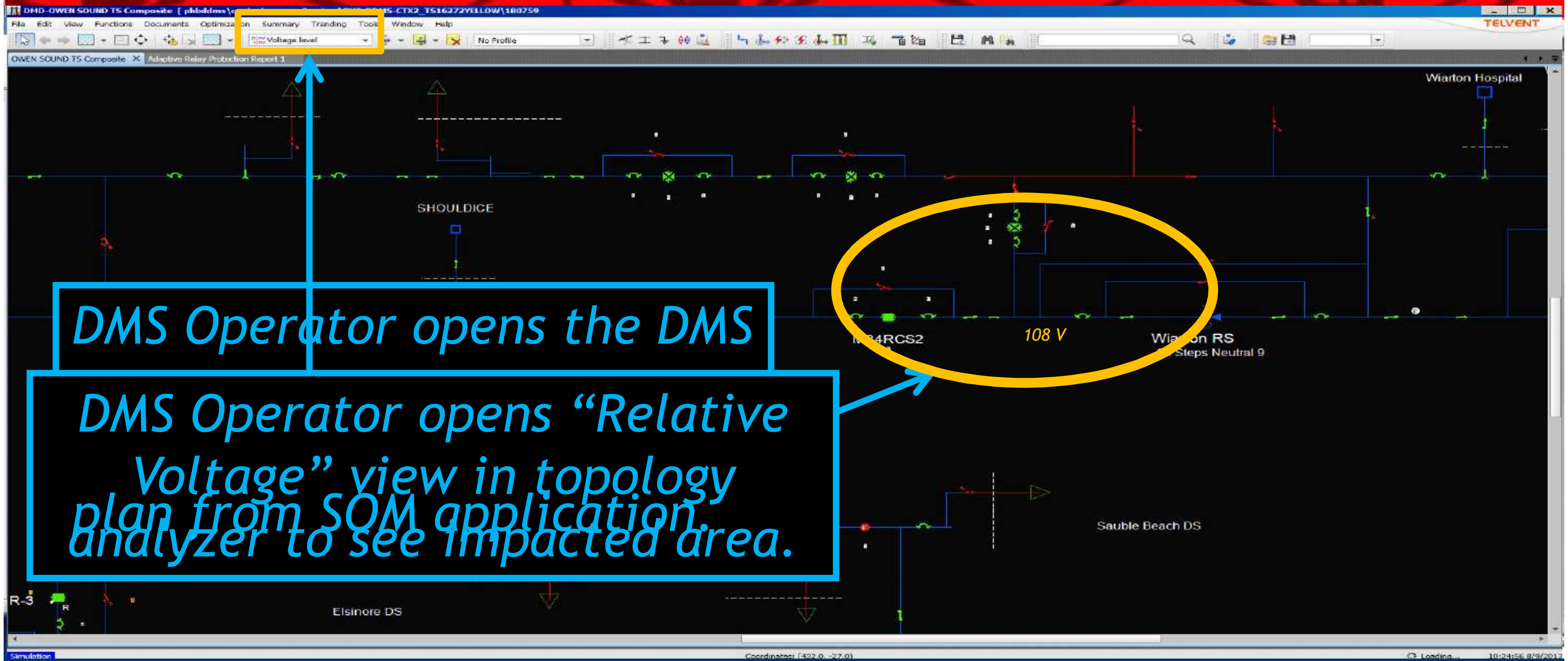


DMS OPERATOR #5- PROACTIVE PLANNING 28



DMS OPERATOR

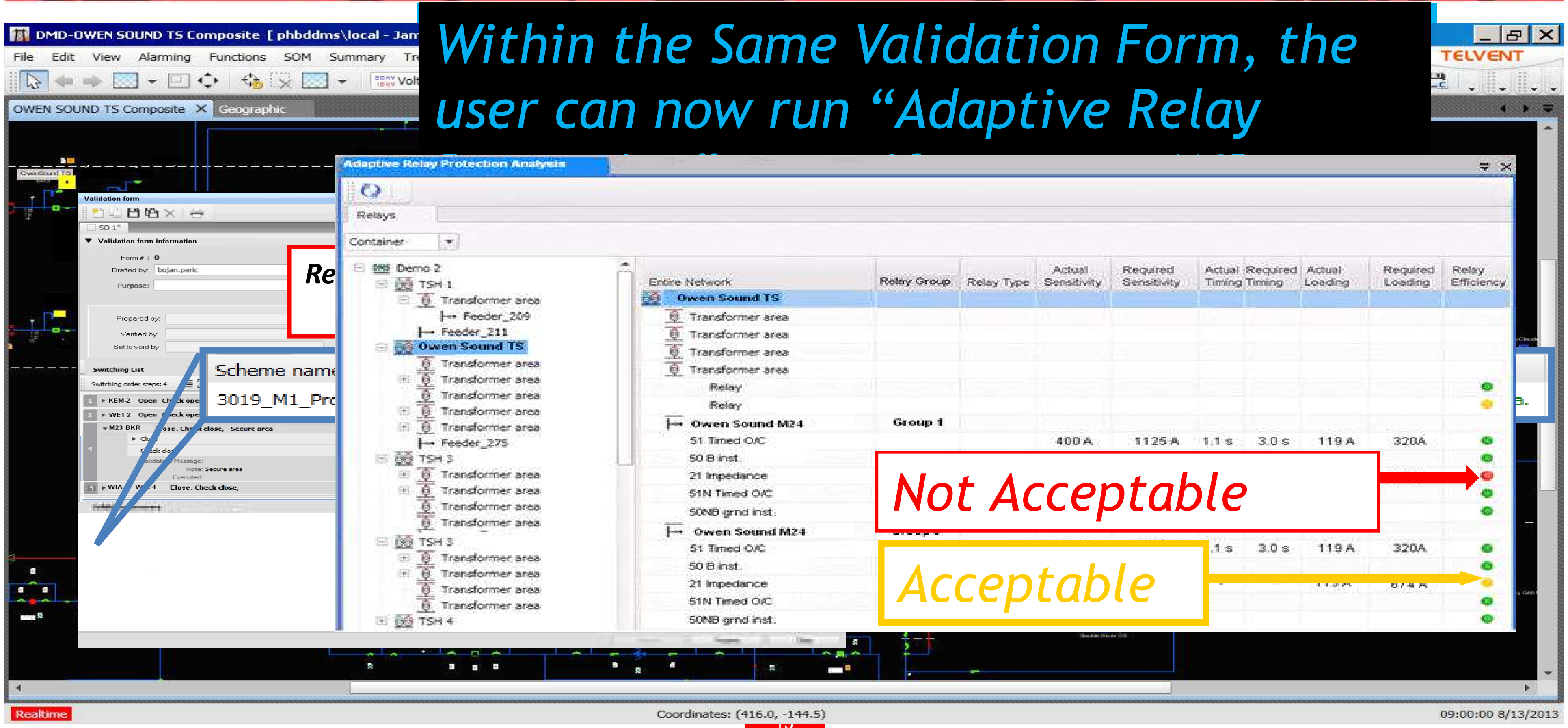
#6 LOW VOLTAGE INQUIRY



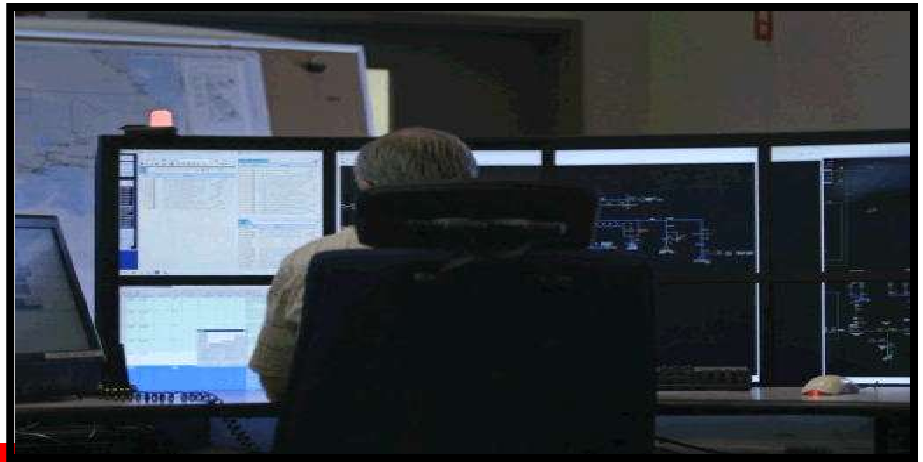
DMS Operator opens the DMS plan from SOM application.

DMS Operator opens “Relative Voltage” view in topology analyzer to see impacted area.

SIMULATION MODE

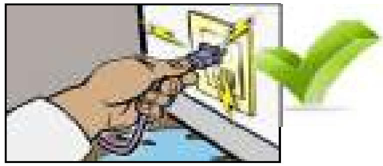

Within the Same Validation Form, the user can now run "Adaptive Relay
DMD-OWEN SOUND TS Composite
Adaptive Relay Protection Analysis
Validation form
Scheme name
3019_M1_Pr
Owen Sound TS
Owen Sound M24
Group 1
51 Timed O/C
50 B inst.
21 Impedance
51N Timed O/C
50NB grnd inst.
400 A
1125 A
1.1 s
3.0 s
119 A
320A
Not Acceptable
Acceptable
Realtime
Coordinates: (416.0, -144.5)
09:00:00 8/13/2013

Field Crew finds the actual location of the fault and relays this information back to the DMS Operator.

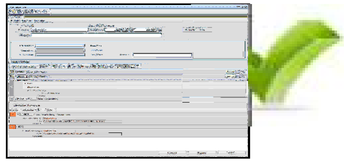


Voltage

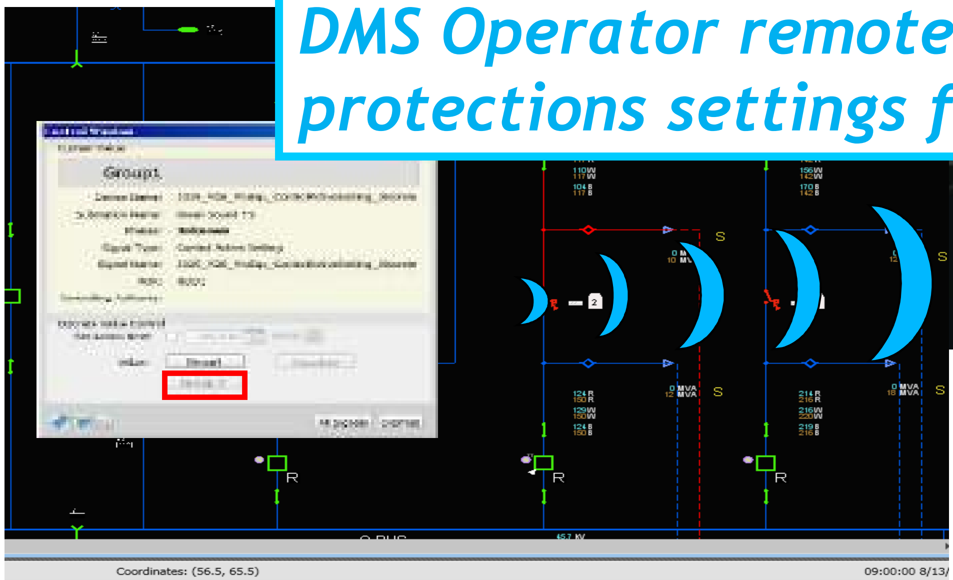
Protections



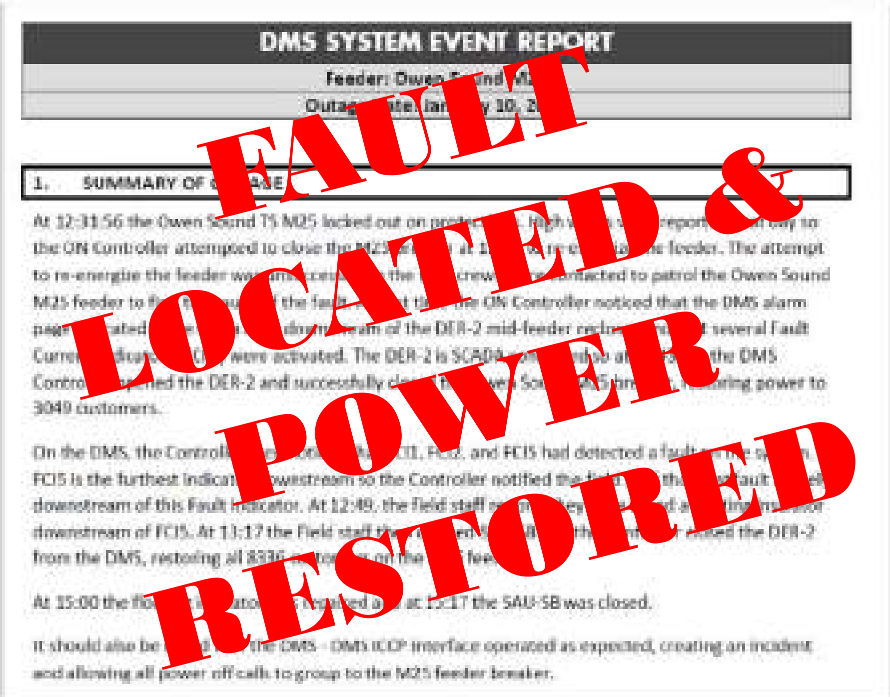
Switch Plan



DMS Operator remotely changes protections settings for field crew.



The Field Crew will now restore power to the unaffected sections and begin repairing the faulted area.



DMS SYSTEM EVENT REPORT

Feeder: Owen [illegible]

Outage [illegible] 10, 2[illegible]

1. SUMMARY OF [illegible]ASE

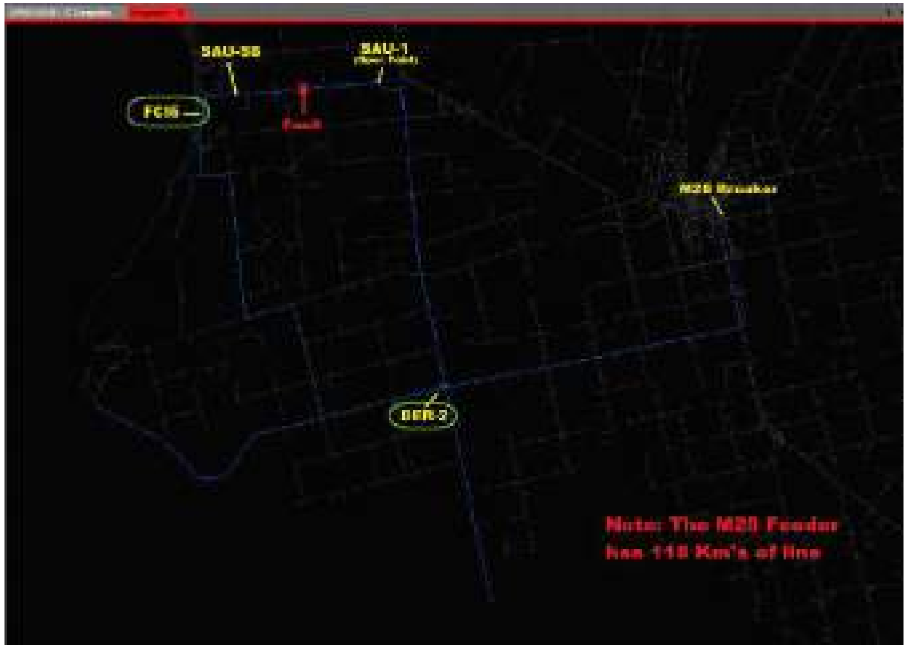
At 12:31:56 the Owen Sound TS M25 locked out on [illegible] the ON Controller attempted to close the M2[illegible] at 1[illegible] feeder. The attempt to re-energize the feeder [illegible] crew [illegible] contacted to patrol the Owen Sound M25 feeder to [illegible] the fault [illegible] the ON Controller noticed that the DMS alarm page [illegible] downstream of the DER-2 mid-feeder [illegible] several Fault Current [illegible] were activated. The DER-2 is SCADA [illegible] the DMS Control[illegible] opened the DER-2 and successfully [illegible] Owen Sound M25 [illegible] restoring power to 3049 customers.

On the DMS, the Controll[illegible] FCI1, FCI2, and FCI5 had detected a fault [illegible] FCI5 is the furthest indicat[illegible] downstream so the Controller notified the [illegible] fault [illegible] downstream of this Fault Indicator. At 12:49, the field staff [illegible] downstream of FCI5. At 13:17 the Field staff [illegible] closed the DER-2 from the DMS, restoring all 8336 [illegible] on the [illegible] feeder.

At 15:00 the [illegible] at 15:17 the SAU-SB was closed.

It should also be [illegible] the DMS - DMS ICCP interface operated as expected, creating an incident and allowing all power off calls to group to the M25 feeder breaker.

DMS Display of 118 kM Hydro One Feeder



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Questions?

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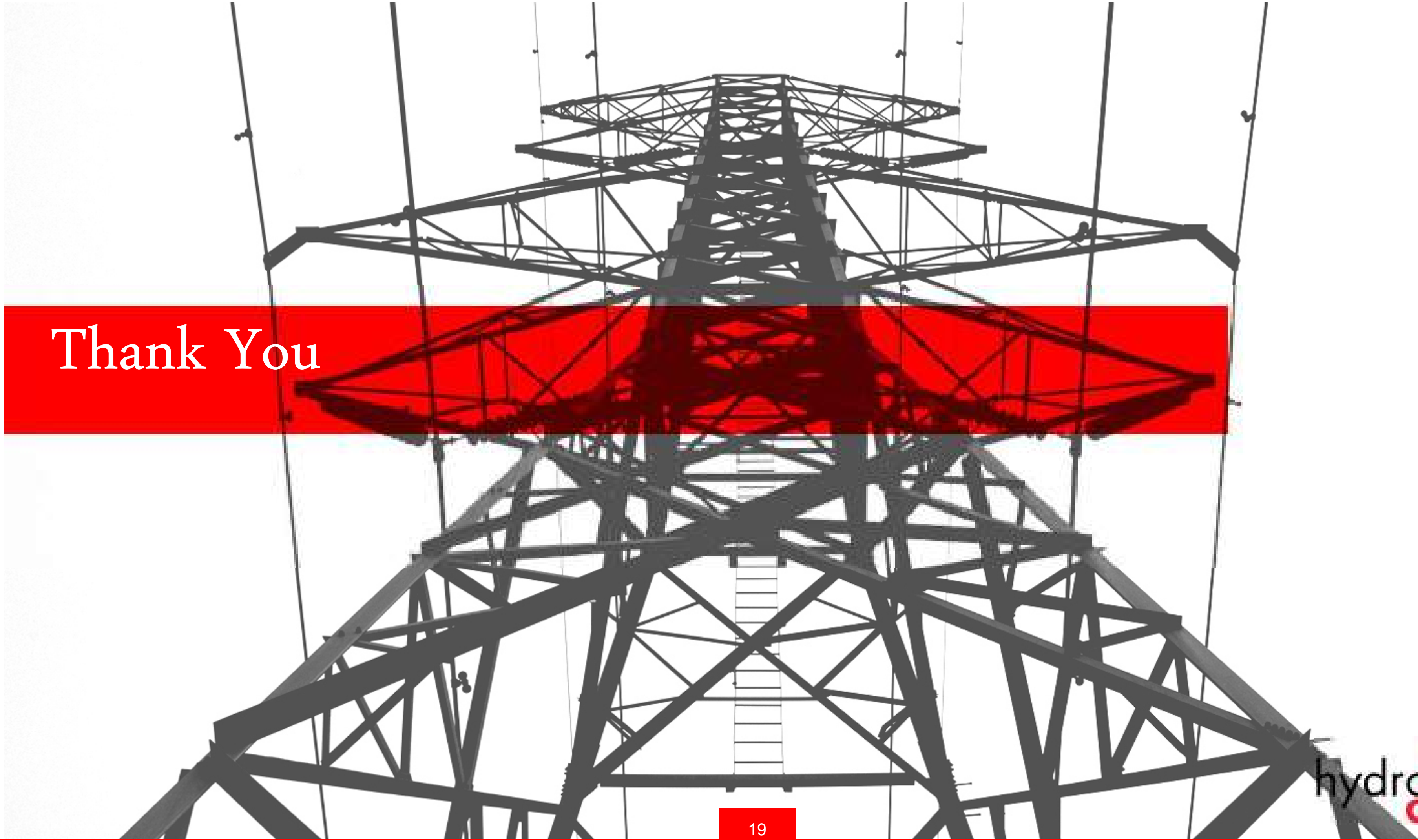
Thank You



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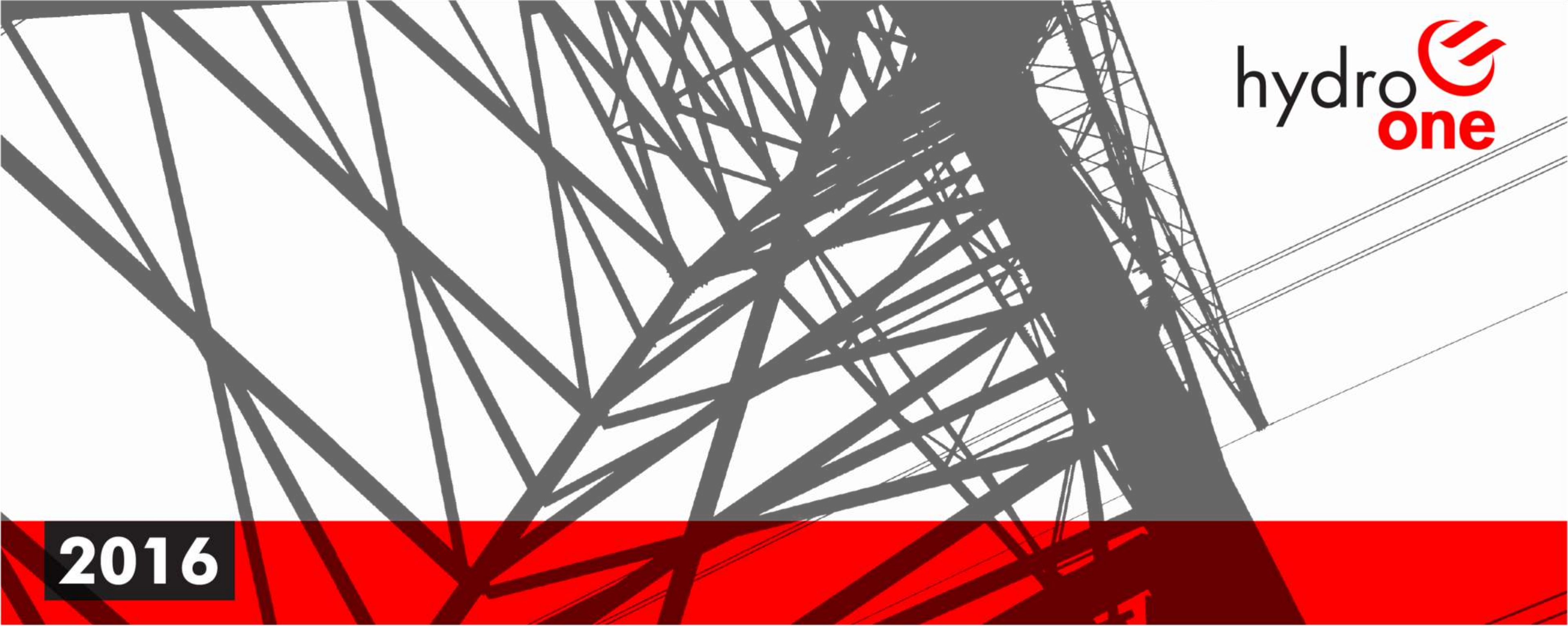
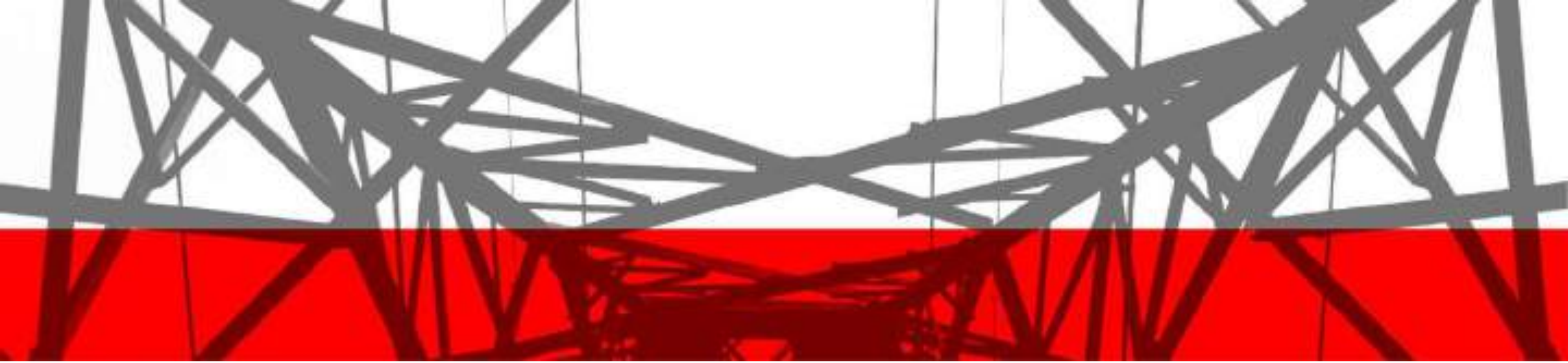


2016

LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



LOAD DISPLACEMENT GENERATION, NET METERING AND ENERGY STORAGE

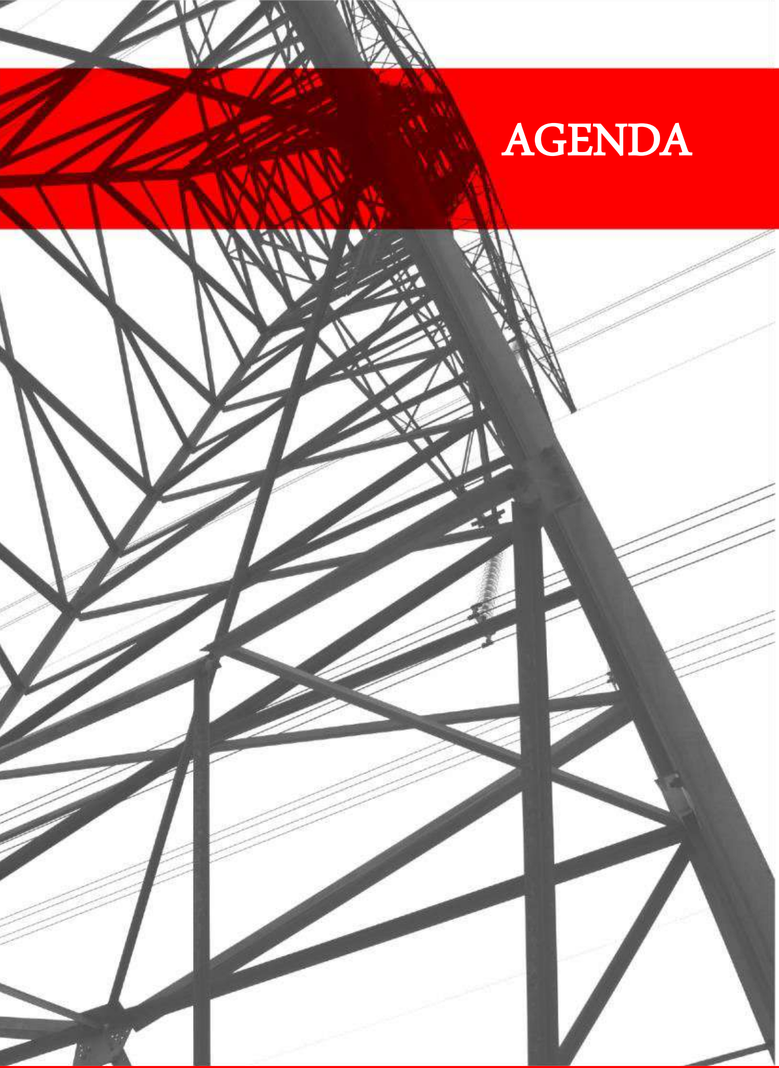
Monika Amorim

Senior Settlement Analyst

Transmission and Distribution Settlements

Hydro One

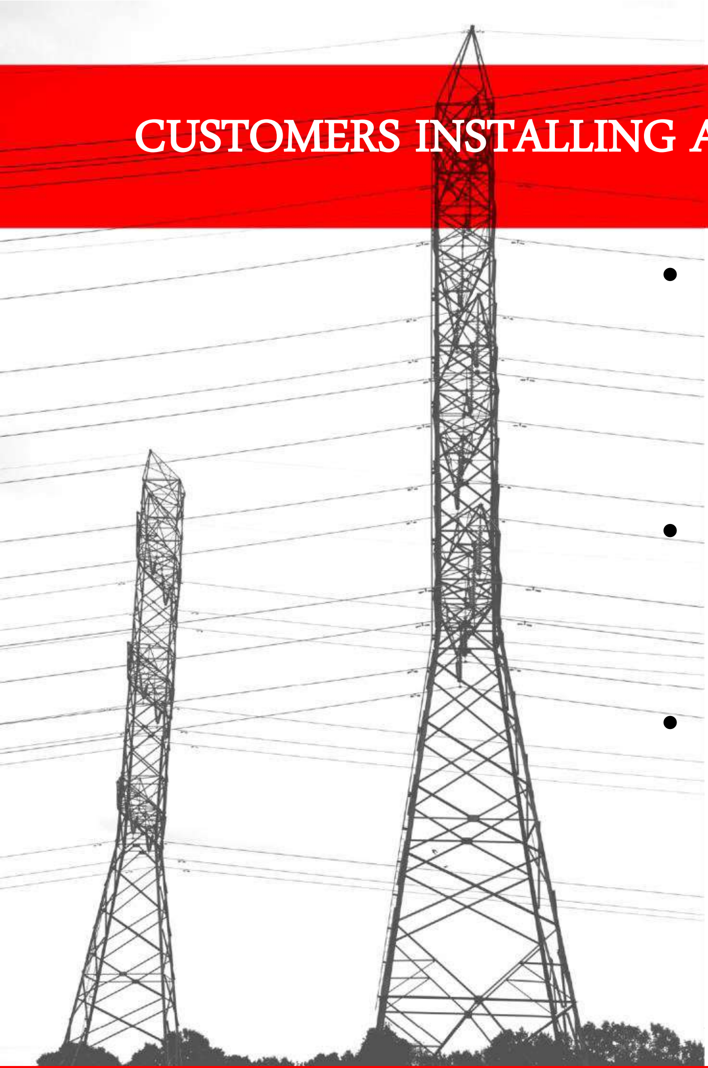
AGENDA



- Gross Load Billing
- Net Metering
- Energy Storage

GROSS LOAD BILLING

CUSTOMERS INSTALLING A GENERATOR



- Customer Impact Assessment is needed for installing load displacement/backup generator >10 kW as per Hydro One's Condition of Services

- Distribution Connection Agreement must be executed for connecting any >10 kW generator

- Customers with a load displacement generator cannot backfeed into the grid

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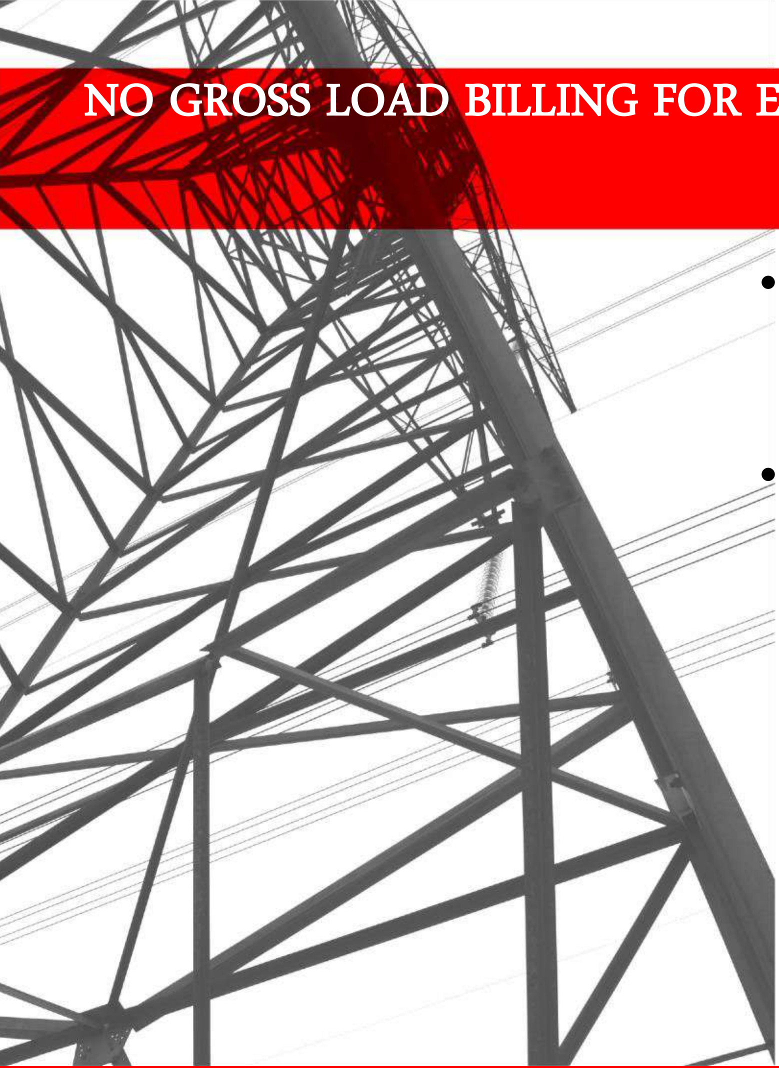
KEY NOTES FOR LOAD DISPLACEMENT GENERATORS

- A customer wants to reduce their electricity bill, in particular Global Adjustment
  - Class B customers want to reduce the total kWh based Global Adjustment charges
  - Class A customers want to avoid or reduce demand during the IESO system peaks to lower their Peak Demand Factor
- Customer is incented by IESO to install a generator under Conservation Demand Management
- Customer needs to self declare Debt Retirement payment to Ministry of Finance
  - Current forecasted Debt Retirement Charge expiry is March 31, 2018
- Load Displacement generation may impact a customer's Class A qualification
  - Please consult Meghan Atkinson (Meghan.Atkinson@HydroOne.com) for more information
- Depending on type and size of the generator, customer may or may not attract Gross Loading Billing

NO GROSS LOAD BILLING FOR EMERGENCY BACKUP GENERATOR



- GLB does not apply to emergency backup generator
  https://www.ontario.ca/laws/regulation/r07516

- "standby power source" means equipment that is intended to be used for the purpose of producing power to maintain operating conditions when the power produced by the normal sources of power is cutoff or reduced

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GROSS LOAD BILLING

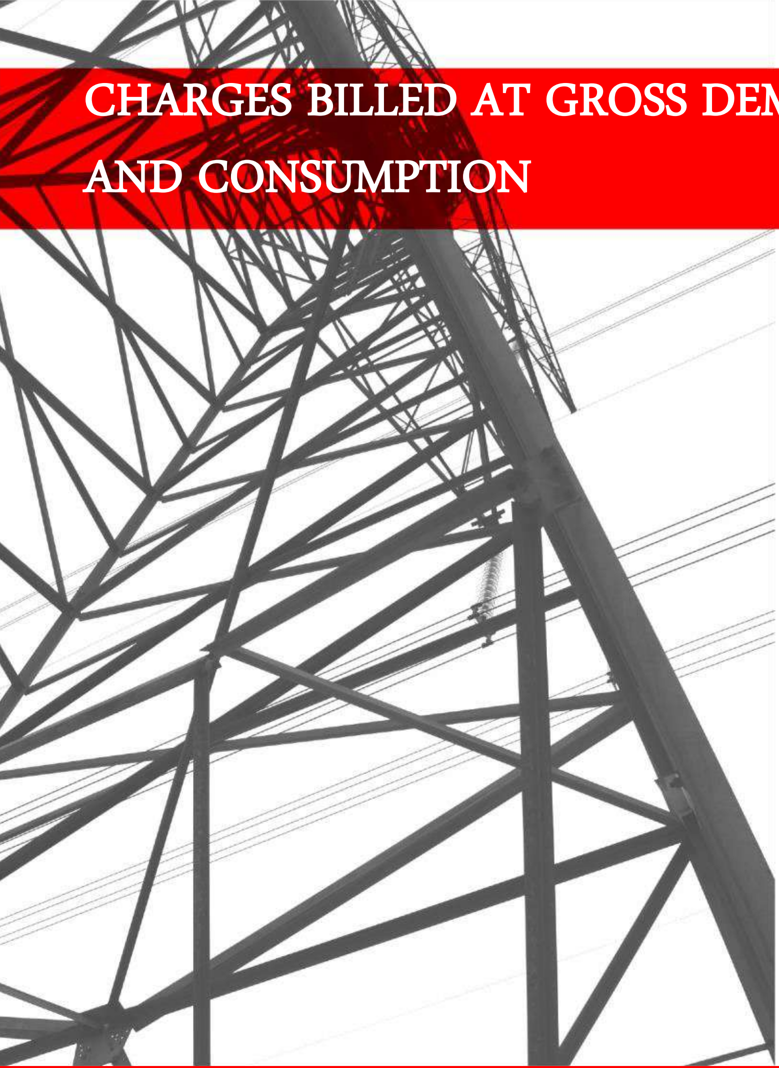
- Gross Load Billing is triggered where:
  - A generator is connected to an existing load

- Where the generator exceeds
  - 2 MW for renewable, or
    - wind, solar, biomass, bio-oil, bio-gas, landfill gas, or water
  - 1 MW for non-renewable

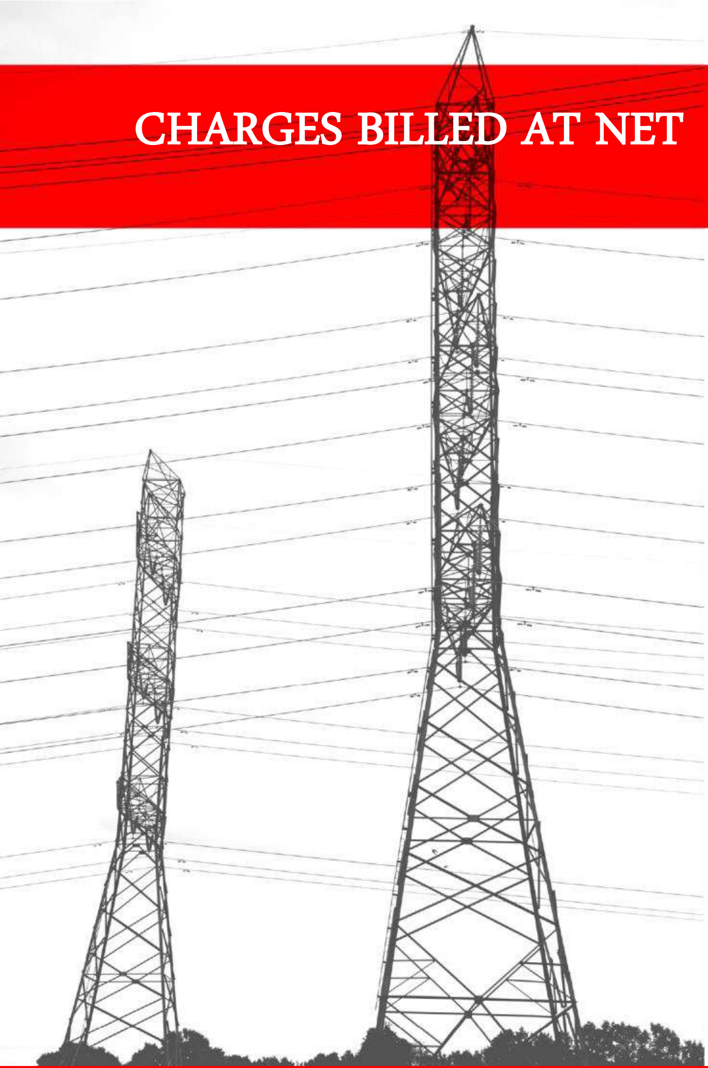
- A meter must be installed to measure the generator output

- As per OEB-approved Hydro One Distribution Rate Schedule: GLB recovers the costs of Hydro One built assets in order to meet customer's maximum demand

CHARGES BILLED AT GROSS DEMAND AND CONSUMPTION



- Delivery
  - Common ST
  - Transmission Line Connection
  - Transmission Transformation Connection / HVDS High Facility Charge
  - Volumetric Rate Riders
- The above are all based on the overall peak for a billing period
- Debt Retirement Charge
  - Customers with a generator must self-declare for Debt Retirement Charge
  - http://www.fin.gov.on.ca/en/guides/drc/101.html



CHARGES BILLED AT NET

- Transmission Network Service Charge
  - Net Demand
  - Based on the peak reached on business days from 7am to 7pm – local time
  - The optimum time to run generator would be on Business Days from 7am to 7pm, if it is not running 24/7
- Commodity & Regulatory Charges
  - Net consumption (kWh)

GLB BILLING IMPACT EXAMPLE 1

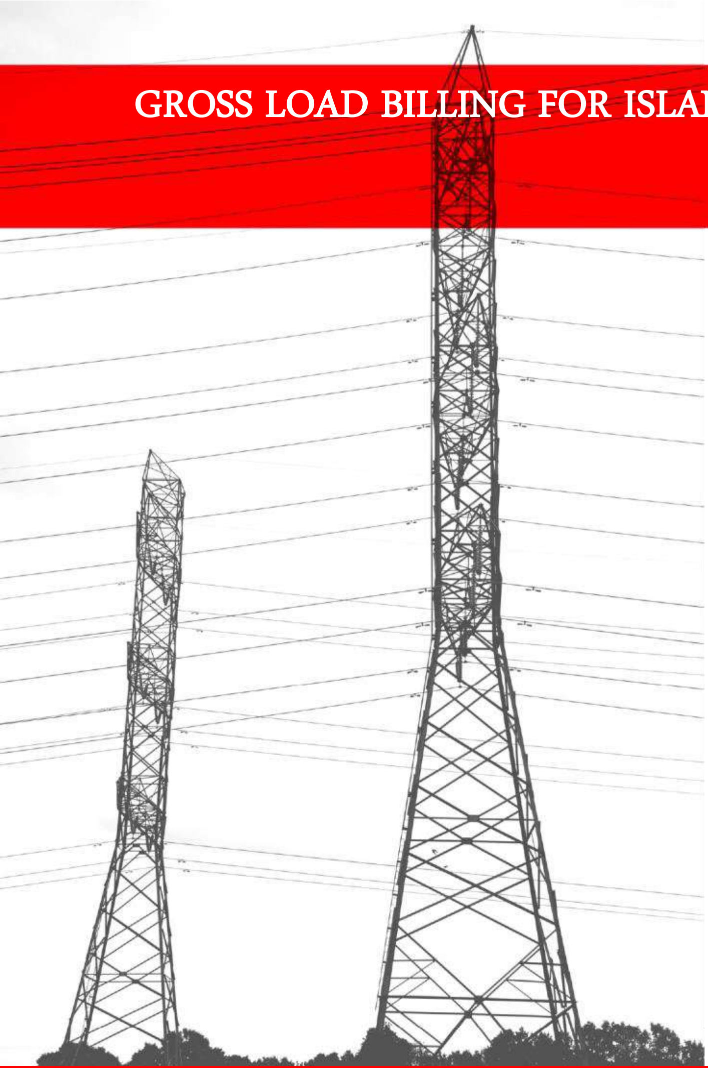
- Class B customer with an average 2MW demand
- Potential monthly savings of **$107,606.25**

Invoice of 2 MW Customer (CLASS B) Without Generation					Invoice of 2 MW Customer (CLASS B) Full Displacement Generator Running On Peak Times (34%)			
Line Item	**Net Amount**	**Rate**	**Quantity**	**Difference**	**Line Item**	**Net Amount**	**Rate**	**Quantity**
Electricity	**$ 27,705.68**	$ 0.0231	1,200,000.00	**$ 19,137.68**	**Electricity**	**$ 8,568.00**	$ 0.0210	408,000.00
Class B GA	**$ 99,240.00**	$ 0.0827	1,200,000.00	**$ 65,498.40**	**Class B GA**	**$ 33,741.60**	$ 0.0827	408,000.00
Delivery					**Delivery**			
Service Charge	$ 481.41	$481.41	1	$ -	Service Charge	$ 481.41	$481.41	1
Meter Charge	$ 741.21	$ 741.21	1	**$ (741.21)**	Meter Charge	$ 1,482.42	$ 741.21	**2**
Rider for Variance - General	$ 11.62	$ 11.62	1	$ -	Rider for Variance - General	$ 11.62	$ 11.62	1
Rider for Foregone Revenue	$ 47.56	$ 47.56	1	$ -	Rider for Foregone Revenue	$ 47.56	$ 47.56	1
Common ST	$ 2,348.00	$ 1.1740	2,000.00	$ -	Common ST	$ 2,348.00	$ 1.1740	2,000.00
Rider for Variance - General - Volumetric	$ 630.20	$ 0.3151	2,000.00	$ -	Rider for Variance - General - Volumetric	$ 630.20	$ 0.3151	2,000.00
Rider for Variance - Wholesale Market Service	$ (893.00)	$ (0.4465)	2,000.00	$ -	Rider for Variance - Wholesale Market Service	$ (893.00)	$ (0.4465)	2,000.00
TX Network Service	$ 6,906.29	**$ 3.3396**	**2,068.00**	**$ 6,906.29**	**TX Network Service**	$ -	**$ 3.3396**	**0.00**
Tx Line Connection	$ 1,611.18	$ 0.7791	2,068.00	$ -	Tx Line Connection	$ 1,611.18	$ 0.7791	2,068.00
Tx Transformation Connection	$ 3,663.05	$1.7713	2,068.00	$ -	Tx Transformation Connection	$ 3,663.05	$1.7713	2,068.00
				$ -				
Regulatory					**Regulatory**			
Wholesale Market Service	$ 4,320.00	$ 0.0036	1,200,000.00	**$ 2,524.80**	Wholesale Market Service	**$ 1,795.20**	$ 0.0044	408,000.00
Rural & Remote Rate Protection	$ 1,560.00	$ 0.0013	1,200,000.00	**$ 1,029.60**	Rural & Remote Rate Protection	**$ 530.40**	$ 0.0013	408,000.00
Ontario Electricity Support Program Charge	$ 1,320.00	$ 0.0011	1,200,000.00	**$ 871.20**	Ontario Electricity Support Program Charge	$ 448.80	$ 0.0011	408,000.00
Standard Supply Admin	$ 0.25	$ 0.25	1	$ -	Standard Supply Admin	$ 0.25	$ 0.25	1
				$ -				
Debt Retirement Charge	**$ 8,123.79**	$ 0.007	1,160,541.59		**Debt Retirement Charge**	**$ 8,123.79**	$ 0.007	1,160,541.59
				$ 12,379.48				
HST	$ 20,516.24				**HST**	$ 8,136.76		
TOTAL	**$ 178,333.49**			**$ 107,606.25**	**TOTAL**	**$ 70,727.24**		

GLB BILLING IMPACT EXAMPLE 2

- Class A customer with an average 5.2MW demand
- No change to Peak Demand Factor
- Potential year 1 monthly savings of $83,781.05

Invoice of 5.2MW Customer Without Generation					Invoice of 5.2MW Customer Full Load Displacement Generator Running On Peak Times (34%)			
Line Item	Net Amount	Rate	Quantity	Difference	Line Item	Net Amount	Rate	Quantity
Electricity	**$ 69,300.00**	$ 0.0231	3,000,000.00	**$ 45,738.00**	**Electricity**	**$ 23,562.00**	$ 0.0231	1,020,000.00
Global Adjustment - Class A	$ 150,000.00	0.00015	$ 1,000,000,000.00	**$ -**	**Global Adjustment - Class A**	$ 150,000.00	0.00015	$ 1,000,000,000.00
Delivery					**Delivery**			
Service Charge	$ 481.41	$ 481.41	1	**$ -**	Service Charge	$ 481.41	$ 481.41	1
Meter Charge	$ 741.21	$ 741.21	1	**$ (741.21)**	Meter Charge	$ 1,482.42	$ 741.21	2
Rider for Variance - General	$ 11.62	$ 11.62	1	**$ -**	Rider for Variance - General	$ 11.62	$ 11.62	1
Rider for Foregone Revenue	$ 47.56	$ 47.56	1	**$ -**	Rider for Foregone Revenue	$ 47.56	$ 47.56	1
Common ST	$ 5,870.00	$ 1.1740	5,000.00	**$ -**	Common ST	$ 5,870.00	$ 1.1740	5,000.00
Rider for Variance - General - Volumetric	$ 1,575.50	$ 0.3151	5,000.00	**$ -**	Rider for Variance - General - Volumetric	$ 1,575.50	$ 0.3151	5,000.00
Rider for Variance - Wholesale Market Service	$ (2,232.50)	$ (0.4465)	5,000.00	**$ -**	Rider for Variance - Wholesale Market Service	$ (2,232.50)	$ (0.4465)	5,000.00
TX Network Service	**$ 17,265.73**	**$ 3.3396**	**5,170.00**	**$ 17,265.73**	**TX Network Service**	**$ -**	**$ 3.3396**	**0.00**
Tx Line Connection	$ 4,027.95	$ 0.7791	5,170.00	**$ -**	Tx Line Connection	$ 4,027.95	$ 0.7791	5,170.00
Tx Transformation Connection	$ 9,157.62	$ 1.7713	5,170.00	**$ -**	Tx Transformation Connection	$ 9,157.62	$ 1.7713	5,170.00
Regulatory					**Regulatory**			
Wholesale Market Service	$ 10,800.00	$ 0.0036	3,000,000.00	**$ 7,128.00**	Wholesale Market Service	**$ 3,672.00**	$ 0.0036	1,020,000.00
Rural & Remote Rate Protection	$ 3,900.00	$ 0.0013	3,000,000.00	**$ 2,574.00**	Rural & Remote Rate Protection	**$ 1,326.00**	$ 0.0013	1,020,000.00
OESP	$ 3,300.00	$ 0.0011	3,000,000.00	**$ 2,178.00**	OESP	$ 1,122.00	$ 0.0011	1,020,000.00
Standard Supply Admin	$ 0.25	$ 0.25	1	**$ -**	Standard Supply Admin	$ 0.25	$ 0.25	1
Debt Retirement Charge	**$ 20,309.48**	$ 0.007	2,901,353.97	**$**	**Debt Retirement Charge**	**$ 20,309.48**	$ 0.007	2,901,353.97
HST	$ 38,292.26			**$ 9,638.53**	**HST**	$ 28,653.73		
TOTAL	**$ 332,848.09**			**$ 83,781.05**	**TOTAL**	**$ 249,067.04**		

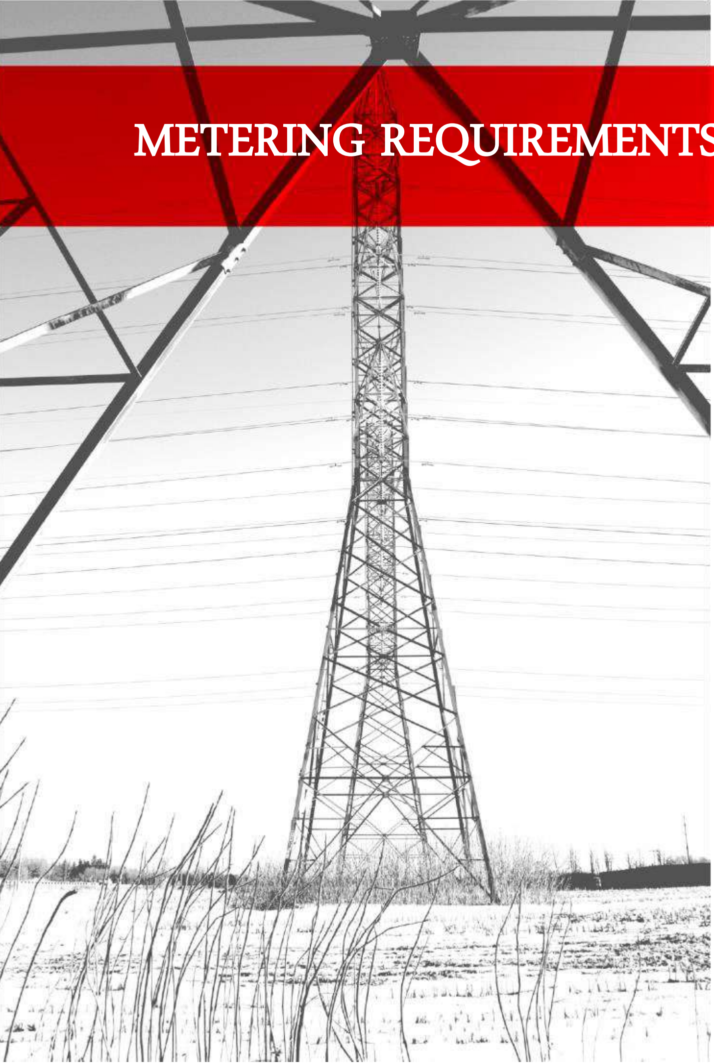


GROSS LOAD BILLING FOR ISLANDING OPERATION WITH LOAD DISPLACEMENT GENERATOR

- A Customer with a load displacement generator operating off-grid is still subject to Gross Load Billing if they are connected to the grid for any back-up supply

- For complete off-grid operation, 365/7/24, Hydro One will not Gross Load Bill the customer but will remove all of the distribution assets from the connection and does not provide back-up support

METERING REQUIREMENTS



- Sub-transmission Customer
  - Hydro One will install a retail revenue meter to measure the generator’s output for Gross Load Billing calculation
  - An additional meter charge will be applied

- General Service Demand Customer
  - Customer will need to install their own meter for Debt Retirement Charge declaration to the Ministry of Finance

HYDRO ONE GLB BUSINESS PROCESS – CUSTOMER NOTIFICATION

- Hydro One's Connection Impact Assessment (CIA) process now includes GLB assessment for any generators with a size of 1MW or more, to make customers aware of GLB eligibility and the settlement impacts

UPCOMING POTENTIAL CHANGES

- OEB is initiating a policy review to address the question of how a commercial and industrial customer should be billed when they have a Load Displacement Generator (LDG) behind the meter

http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/OEBltr_Gross_Load_Billing_Tx_20160329.pdf

NET METERING

NET METERING – EXISTING FRAMEWORK

- Our Net Metering program is available to any Hydro One customer who generates electricity primarily for their own use from a renewable energy source (wind, water, solar radiation or agricultural biomass) using equipment with a total nameplate rating of 500 kW or less

- Net metering allows you to send electricity generated from Renewable Energy Technologies (RETs) to Hydro One's distribution system for a credit towards your electricity costs
    - Excess generation credits can be carried forward for up to 11 months, including the 11th month, to offset future electricity costs

NET METERING – PROPOSED AMENDMENTS

- Remove the capacity limit of 500 kW

- Extend credit carry forward period from 11 months to 12 months

- Virtual Net Metering – credits transfer within multiple accounts within the same LDC within the distance requirement
    - Proposed: 3km

- Pairing of renewable energy sources with energy storage which allows for flexible injection

https://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTI5NTIx&statusId=MTk2Mjg5&language=env

ENERGY STORAGE

ENERGY STORAGE

- Unlike other forms of energy, historically electricity has not been easily stored in large quantities
- Accordingly, the electricity system has operated on a "just-in-time" basis, with decisions about generation output based on real-time demand and the availability of grid capacity to deliver it
- With the emergence of new energy storage technologies this is now changing to allow electricity to be captured and dispatched to the grid whenever it is required
- As required, energy storage systems can act as a load or a generator to balance real-time supply and demand fluctuations
- Energy storage can also benefit the system in the following ways:
  - Smoothing out fluctuations of solar and wind generators, for added stability to the electricity system
  - Easing points of congestion in transmission and distribution networks by temporarily absorbing surges and excess power flow, allowing utilities to defer, or even avoid, expensive system upgrades
  - Absorbing surplus base-load generation when the output from renewable energy sources is high during off-peak hours

Source: http://www.ieso.ca/Pages/Ontario%27s-Power-System/Smart-Grid/Energy-Storage.aspx

ENERGY STORAGE (CONT'D)

Opportunities for Energy Storage in Ontario

The IESO has outlined 3 types of energy storage based on how they interact with the electricity system:

Type 1 – Re-inject stored energy back into the grid (minus reasonable losses)

- Examples: flywheels, batteries, compressed air and pumped hydroelectric

Type 2 – Instead of injecting it back into the grid, use the stored energy to displace electricity consumption (demand) of the host facility at a later time

- Examples: heat storage or ice production for space heating or cooling

Type 3 – Stored energy used in an industrial, commercial or residential process or to displace a secondary form of energy

- They're generally integrated with a host process that uses that secondary form of energy directly or are connected to a transmission or distribution network for their secondary form of energy (e.g., natural gas, steam or coolant)
- Examples: fuel production (hydrogen or methane), steam production and electric vehicles

Source: http://www.ieso.ca/Documents/Energy-Storage/IESO-Energy-Storage-Report_March-2016.pdf

ENERGY STORAGE (CONT'D)

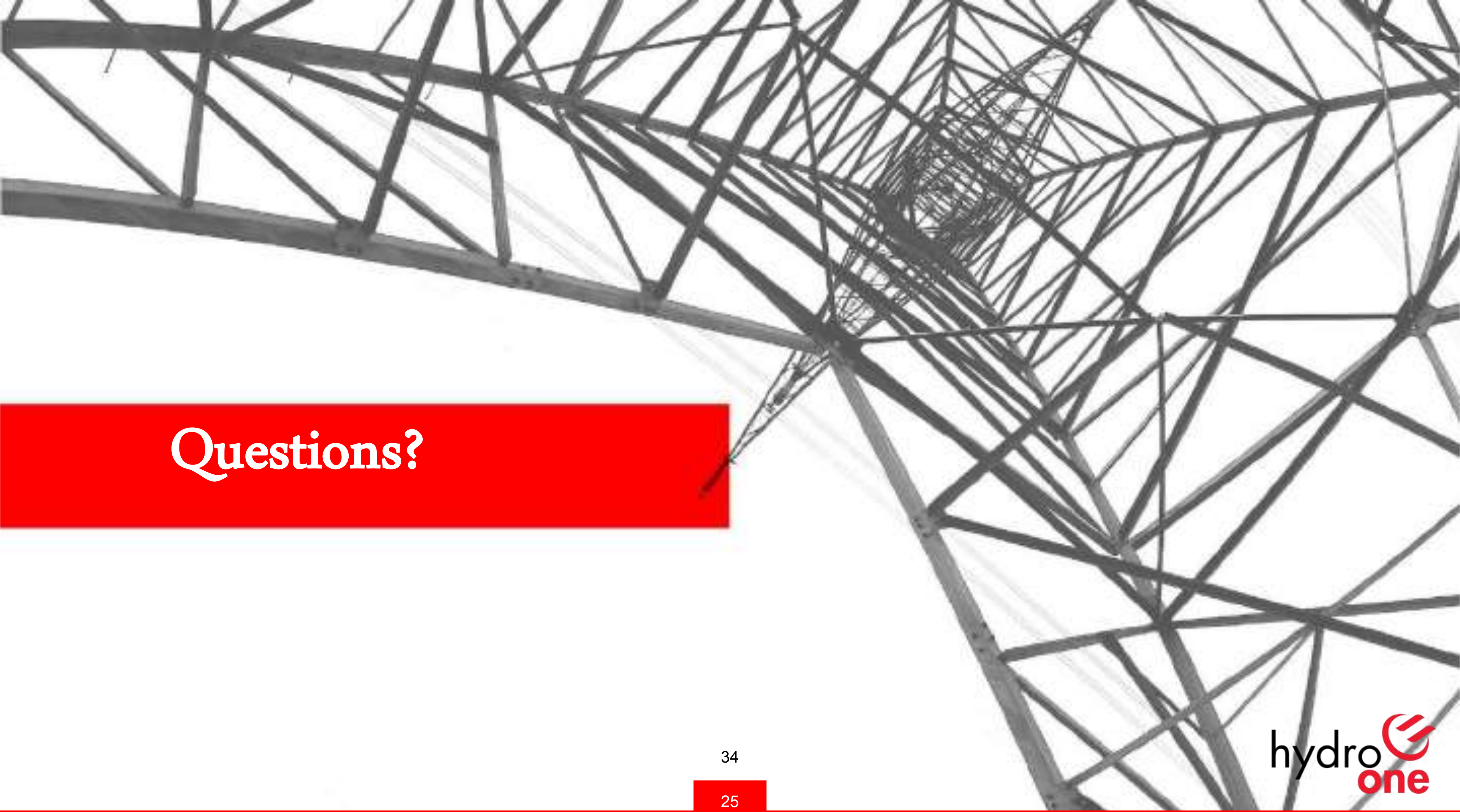
- Reduce demand based charges
    - Lower Network Charge by reducing "on-peak" peak
- Lower the Peak Demand Factor for Class A Global Adjustment by utilizing stored energy during top 5 system peaks
- Optimize hourly pricing rates
- Reduce fossil fuel consumption for backup power

ENERGY STORAGE (CONT'D)

- Proponent is subject to the same Hydro One connection process for distribution generator

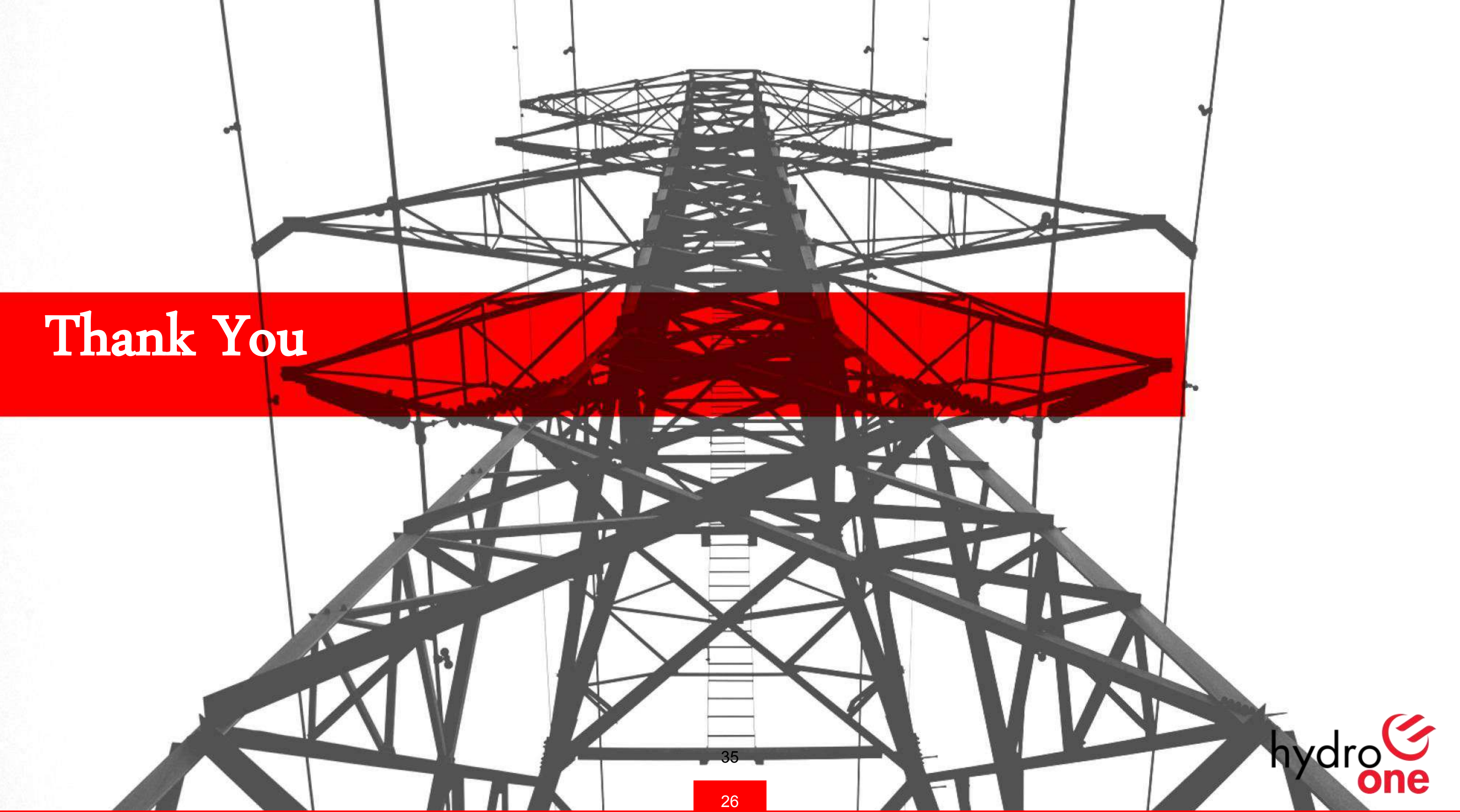
- Industry estimates of 20% loss for kwh transaction – for every 100 kwh withdrawn from the grid, only 80 kwh is injected

- Please check with OEB regarding the requirement of Energy Storage License



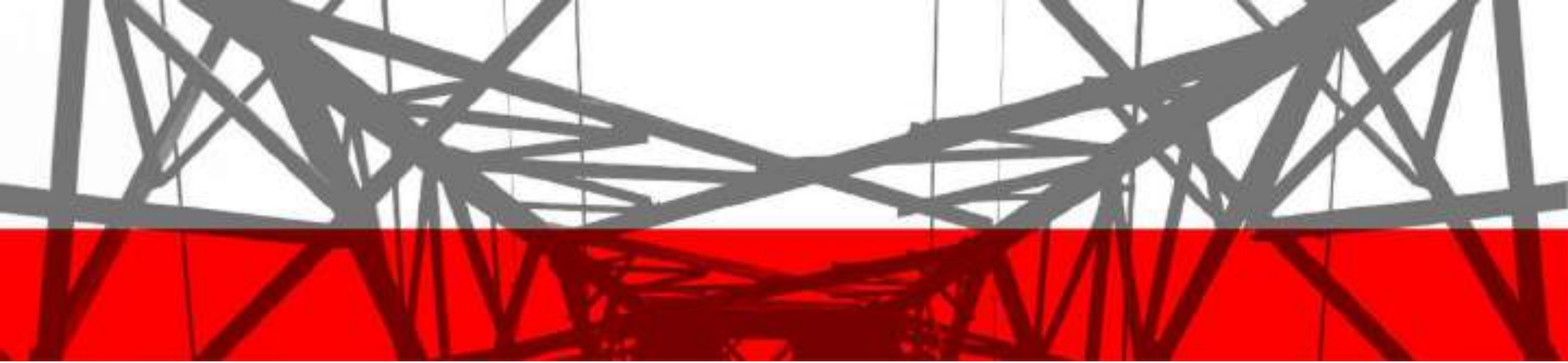
Questions?

Thank You



LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



POWER DISTRIBUTION OPERATIONS

Tam Kennedy

Superintendent Provincial Lines, Hydro One

ONTARIO GRID CONTROL CENTRE

38

ABOUT THE ONTARIO GRID CONTROL CENTRE

- Manages the transmission and distribution networks in Ontario
- 24/7 shift operation & back office support
- Ensures reliable power system to supply customers in real time
- Monitors system conditions, responding to contingencies and unforeseen situations
- Executes outages, both planned and emergent
- Dispatch and response coordination

REAL TIME CUSTOMER SUPPORT

- Whenever a large customer experiences an unplanned outage, Controllers and Dispatchers (DOMC) work in conjunction to re-energize the circuit

- The Controllers analyze the problem using the Network Management System and respond accordingly

- If equipment has failed, DOMC will dispatch field staff to investigate. Further work orders will be created depending on the issue

Key Statistics (2015)

Forced outages	27,078	Provincial Lines Dispatched	53,219	Stations
Average time of forced outage	4.2hrs	Dispatched	9,868	

REAL TIME CUSTOMER SUPPORT

STATISTICS

Issued Work Protection (2015): 3,860
Command Control Operations (2015): 533,522
SCADA Alarms Managed (2015): 11,192,410

Number of Inbound Calls (2015): 440,286
Number of Outbound Calls (2015): 299,317

Number of Retail Customers
(homes, farms, seasonal, small business): ~1.4M

Distribution Lines: 122,460 km
Distribution Stations: 1,024
Distribution Poles: 1,600,000

Large Industrial Customers: 87
Large Distribution Customers: 96
Local Distribution Companies: 73
Major Generators Connected: 155

hydro one

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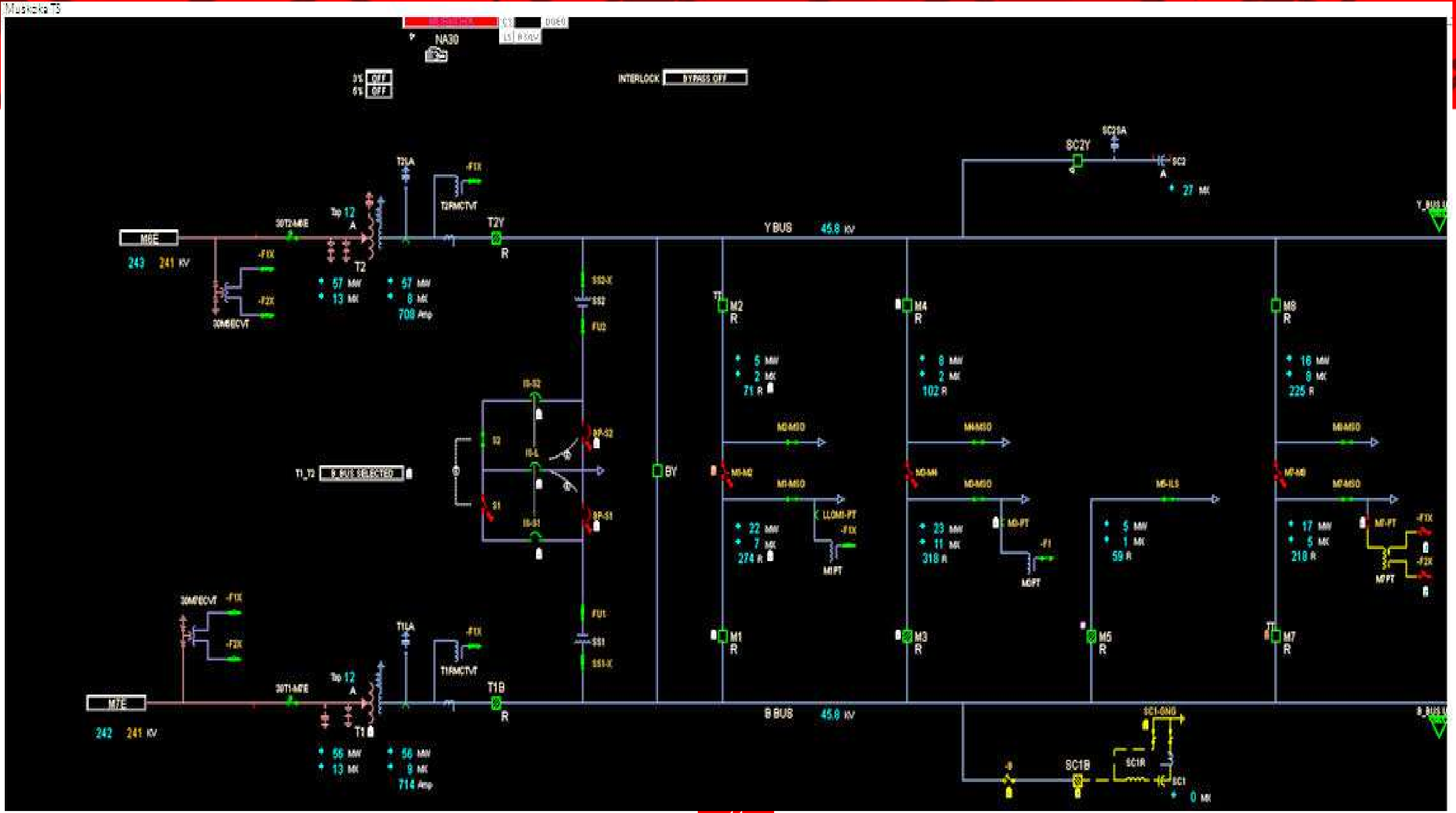
OPERATIONS MANAGER WORKSTATION

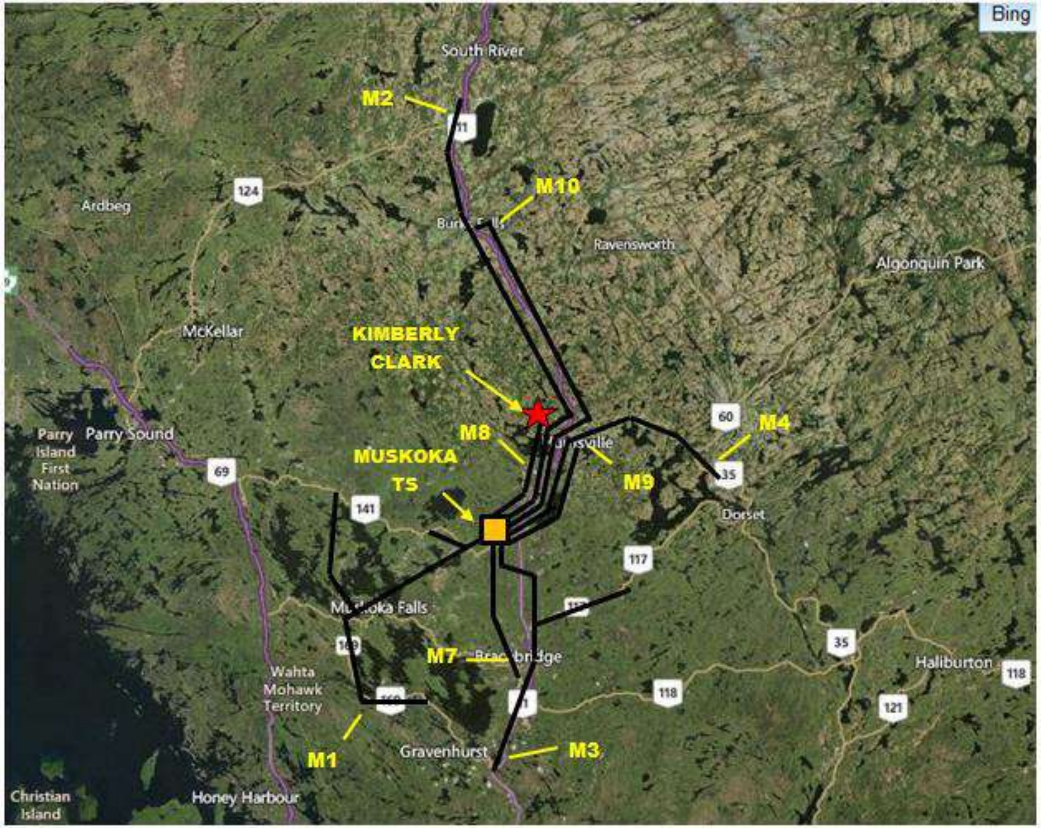
44

CONTROLLER WORKSTATION



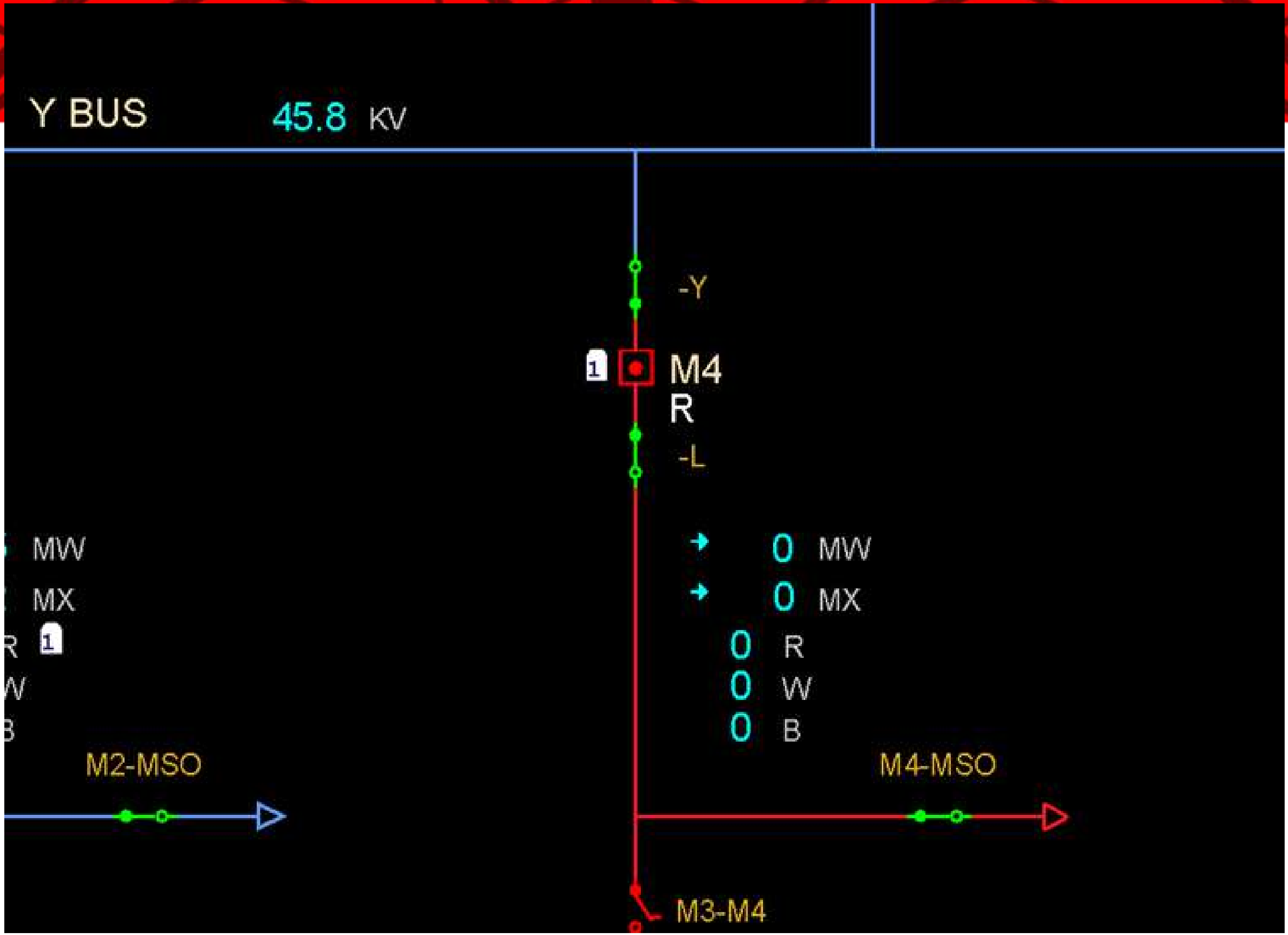
Muskoka TS
NA30
INTERLOCK
BYPASS OFF
M6E
243
241 KV
T2
T2Y
R
Y BUS
45.8 KV
57 MW
13 MX
57 MW
8 MX
708 Amp
T2LA
T2RMCTVT
SC2Y
SC2SA
SC2
27 MX
M2
R
M4
R
M8
R
5 MW
2 MX
71 R
8 MW
2 MX
102 R
16 MW
8 MX
225 R
BY
T1_T2
B BUS SELECTED
22 MW
7 MX
274 R
23 MW
11 MX
318 R
5 MW
1 MX
59 R
17 MW
5 MX
218 R
M1
R
M3
R
M5
R
M7
R
M7E
242
241 KV
T1
T1B
R
T1LA
T1RMCTVT
B BUS
45.8 KV
56 MW
13 MX
56 MW
9 MX
714 Amp
SC1B
SC1R
SC1
0 MX

MUSKOKA TS 44 KV FEEDERS - OVERVIEW



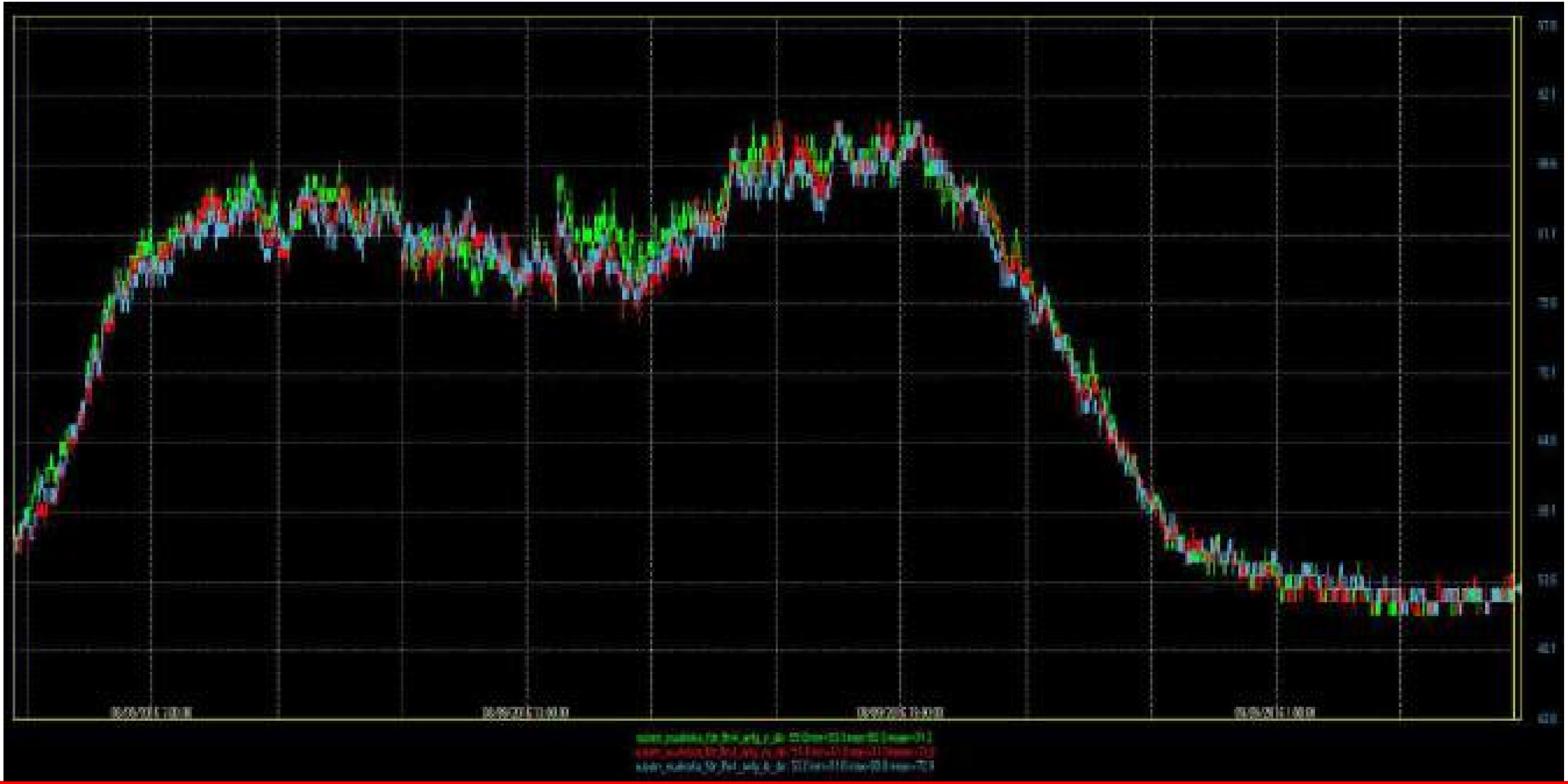
Feeder	km
M1	98
M2	78
M3	58
M4	43
M7	35
M8	22
M9	25
M10	63
TOTALS:	422


Muskoka M4 R, W & B amps MW/MX
Y BUS
45.8 KV
-Y
M4
R
-L
MW
MX
R
W
B
8 MW
2 MX
102 R
99 W
101 B
M2-MSO
M4-MSO
M3-M4

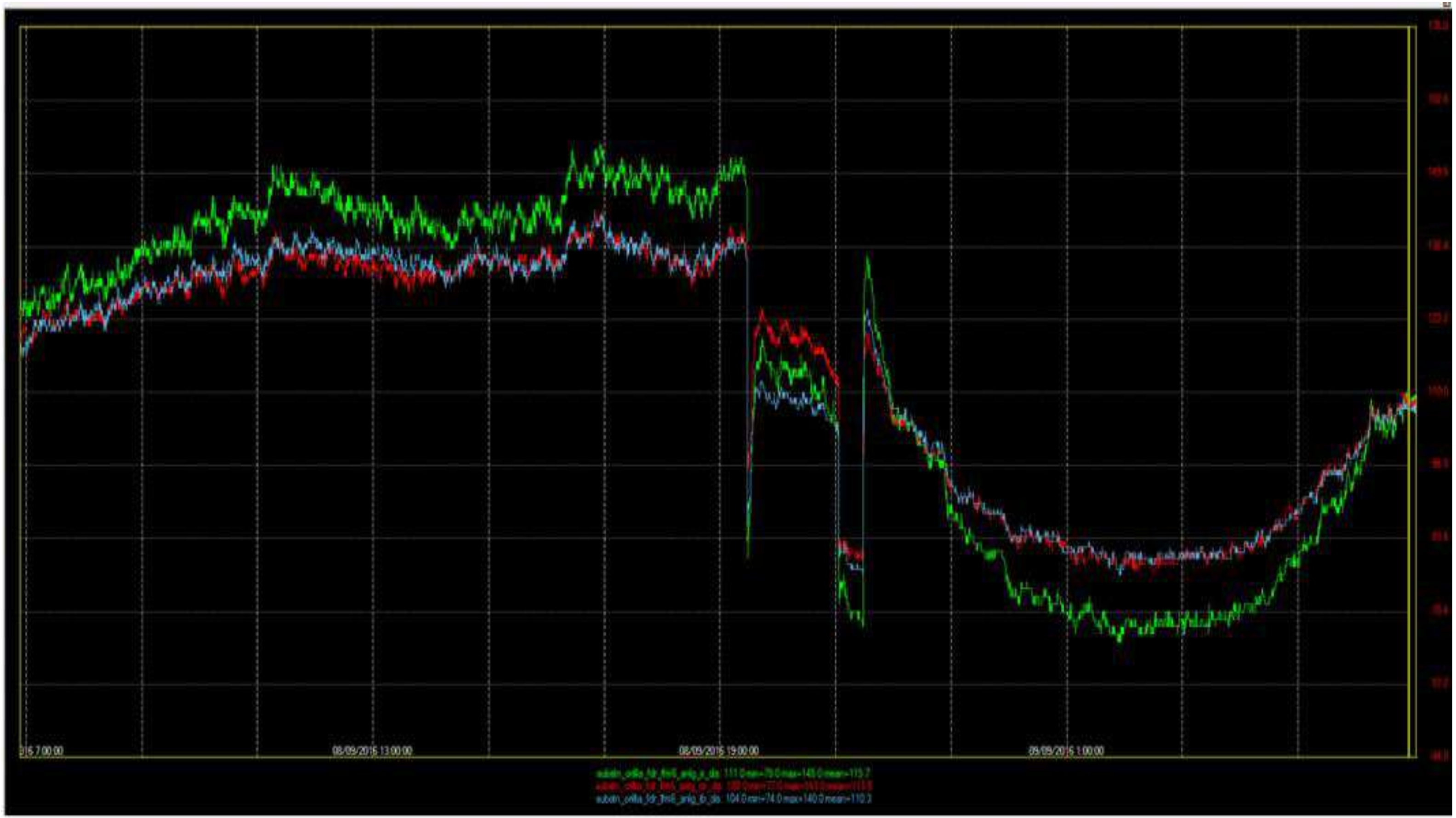

Y BUS
45.8 KV
-Y
1
M4
R
-L
0 MW
0 MX
0 R
0 W
0 B
MW
MX
1
M2-MSO
M4-MSO
M3-M4


52

NORMAL 44 KV FEEDER 24 HOUR LOAD PATTERN



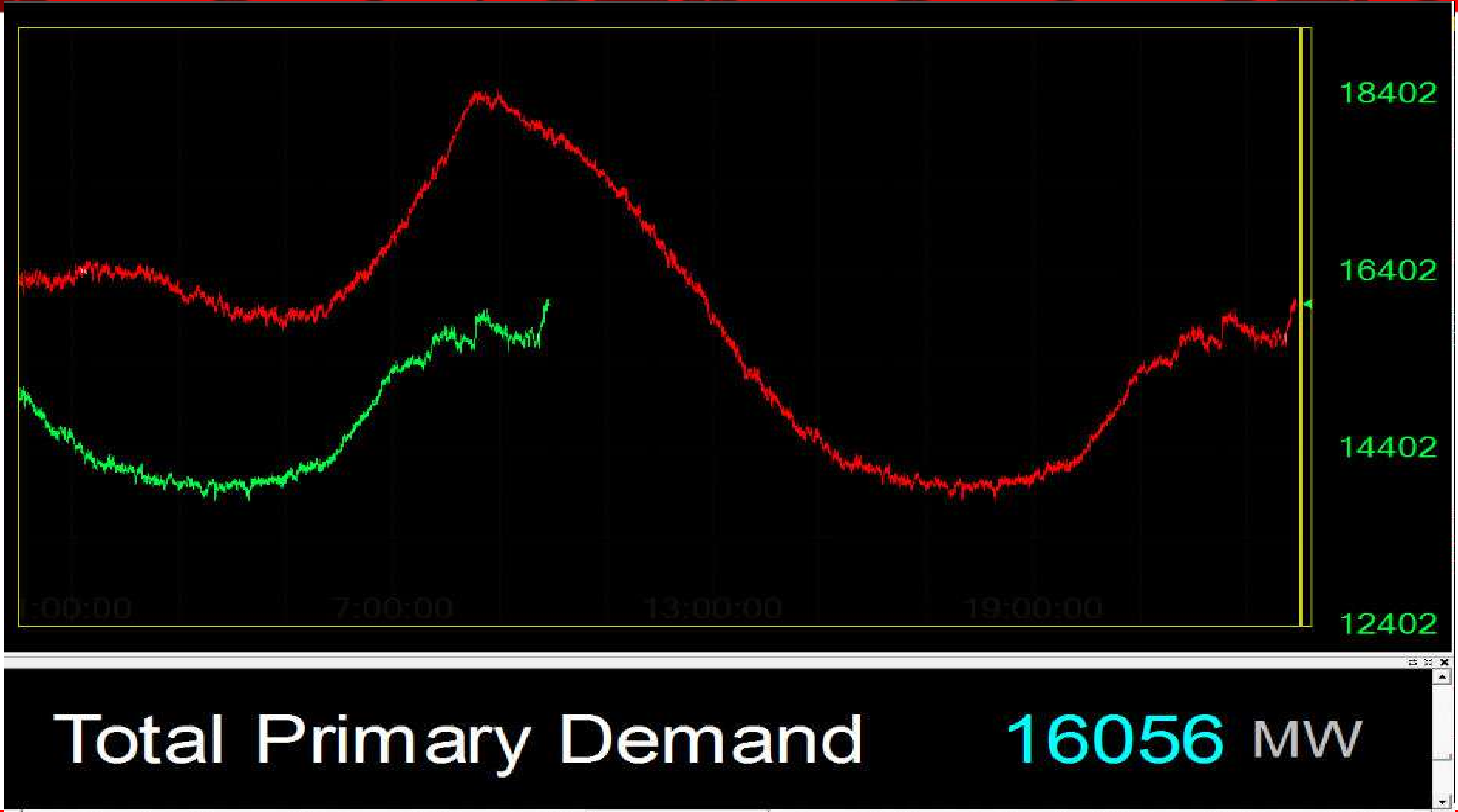
44 KV LOAD PATTERN WITH FEEDER FAULT

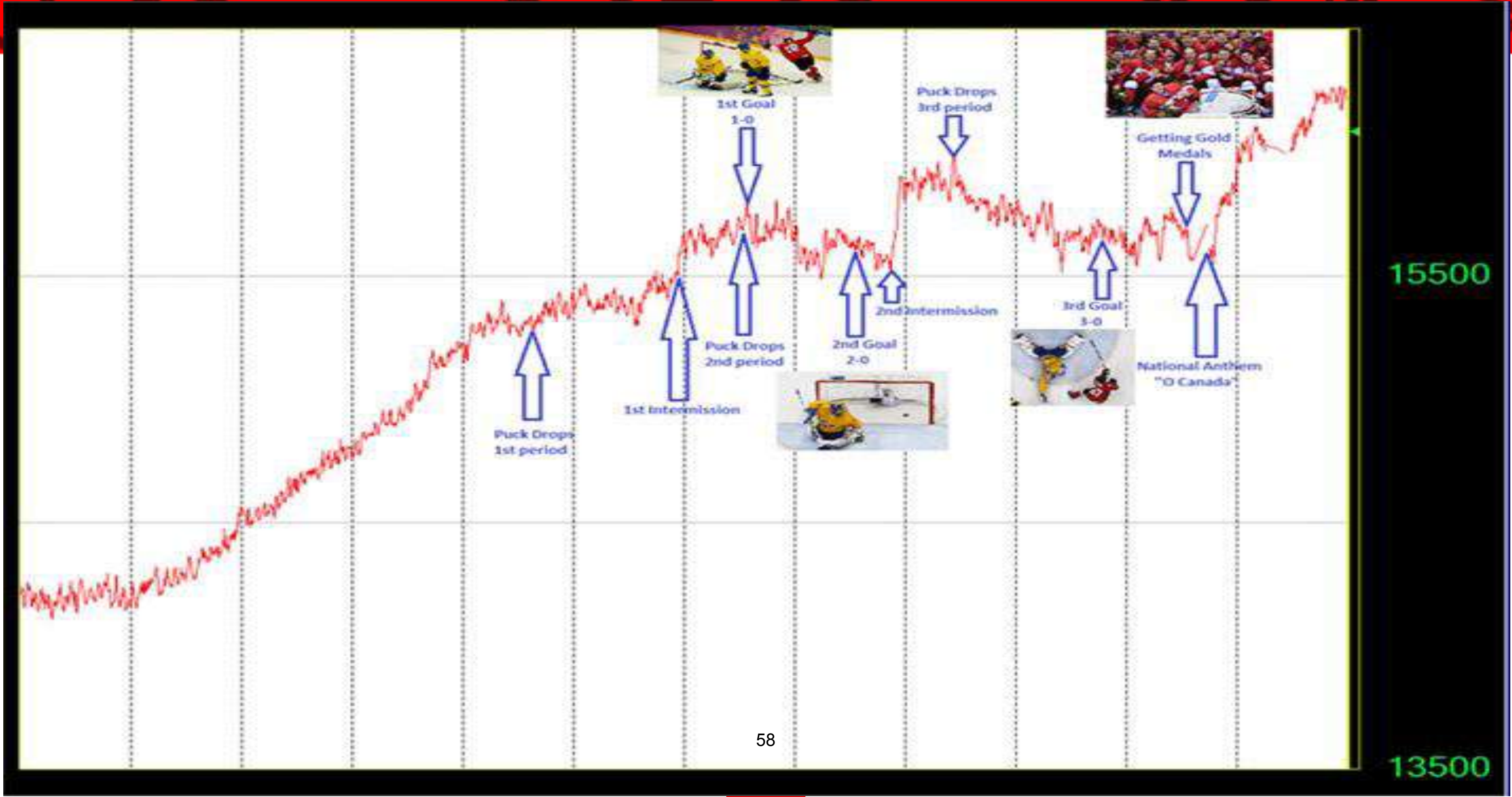


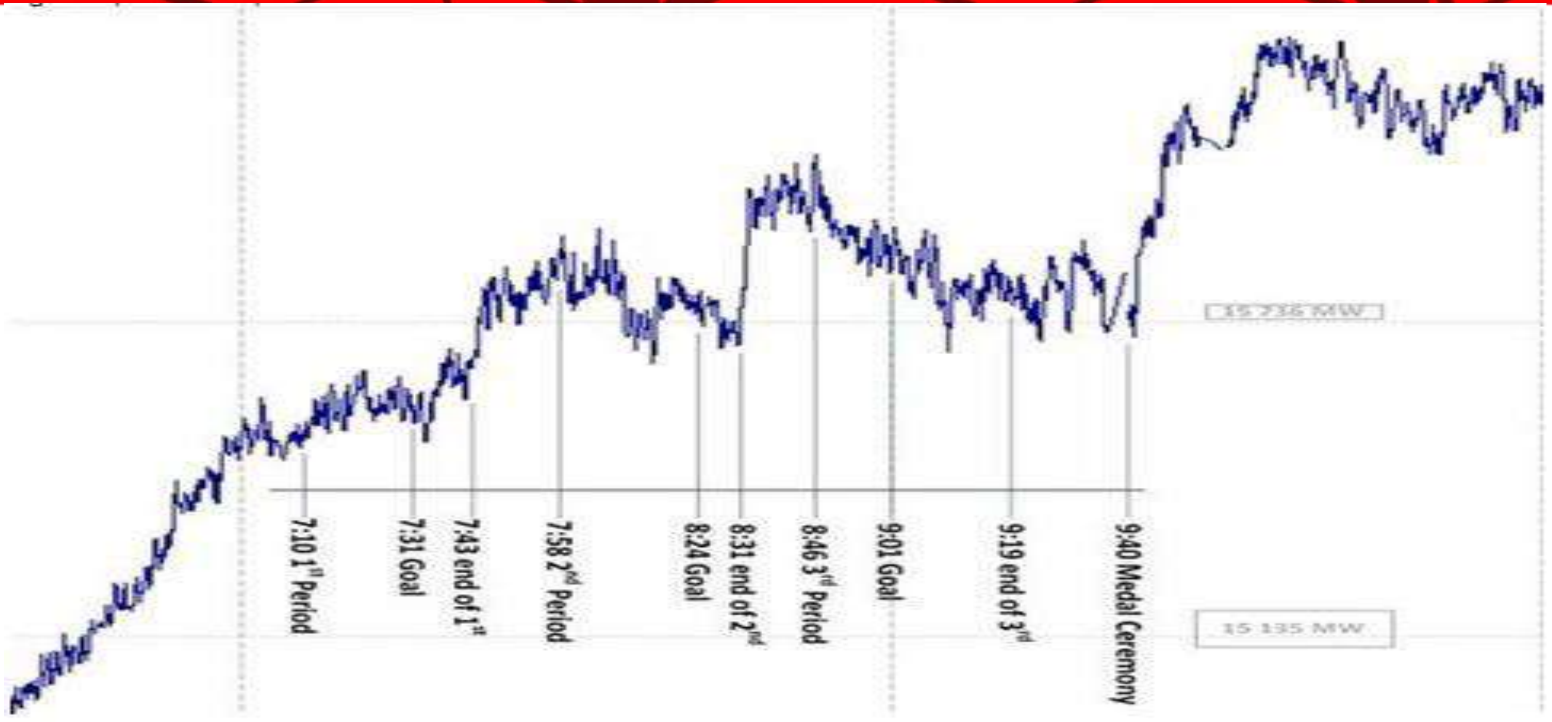
SOLAR GENERATION OUTPUT ONTO FEEDER

FEEDER LOADING WITH SOLAR GENERATION

CONSUMER BEHAVIOUR AFFECTS DEMAND




1st Goal
1-0
Puck Drops
3rd period
Getting Gold
Medals
15500
Puck Drops
2nd period
2nd Goal
2-0
2nd Intermission
3rd Goal
3-0
National Anthem
"O Canada"
1st Intermission
Puck Drops
1st period
13500

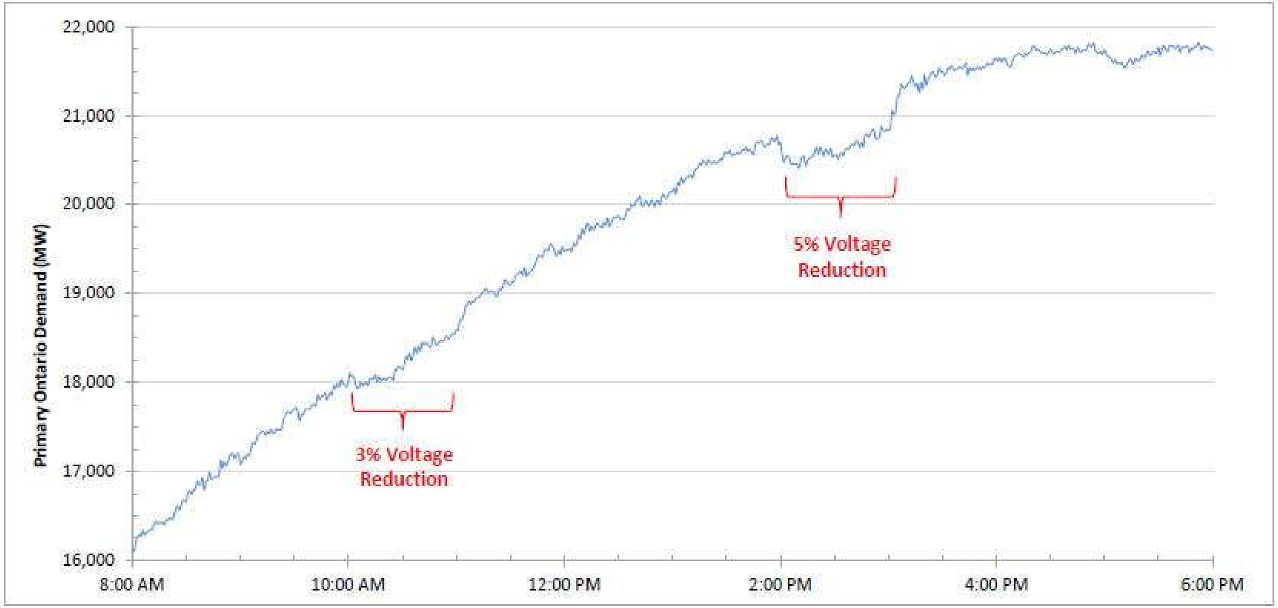


Highlights of this time line:

1. 07:10 load growth stalled as game began.
2. 07:43 end of first period saw a 140MW load increase.
3. 07:58 second period starts and load growth stalls again.
4. 08:31 end of 2nd period saw a 300MW load increase.
5. 08:46 3rd period begins and people are again glued to the TV. (load stalled)
6. 09:40 Medals and anthem are done and people begin to return to normal routines.

3% & 5% VOLTAGE REDUCTION(AUG 9 2016)

Initial data analysis for the August 9th voltage reduction exercise was a drop of 194 MW or 1.1% in primary demand for the 3% test and 375 MW or 1.8% reduction in primary demand for the 5% voltage reduction test.



Special points of interest:

- At the height of the storm over 112,742 customers were without power.
- Over 1,200 Hydro One personnel assisted in restoration operations.
- 7 Helicopters were patrolling feeders at the height of restoration operations.

Hydro One Wind Storm Response

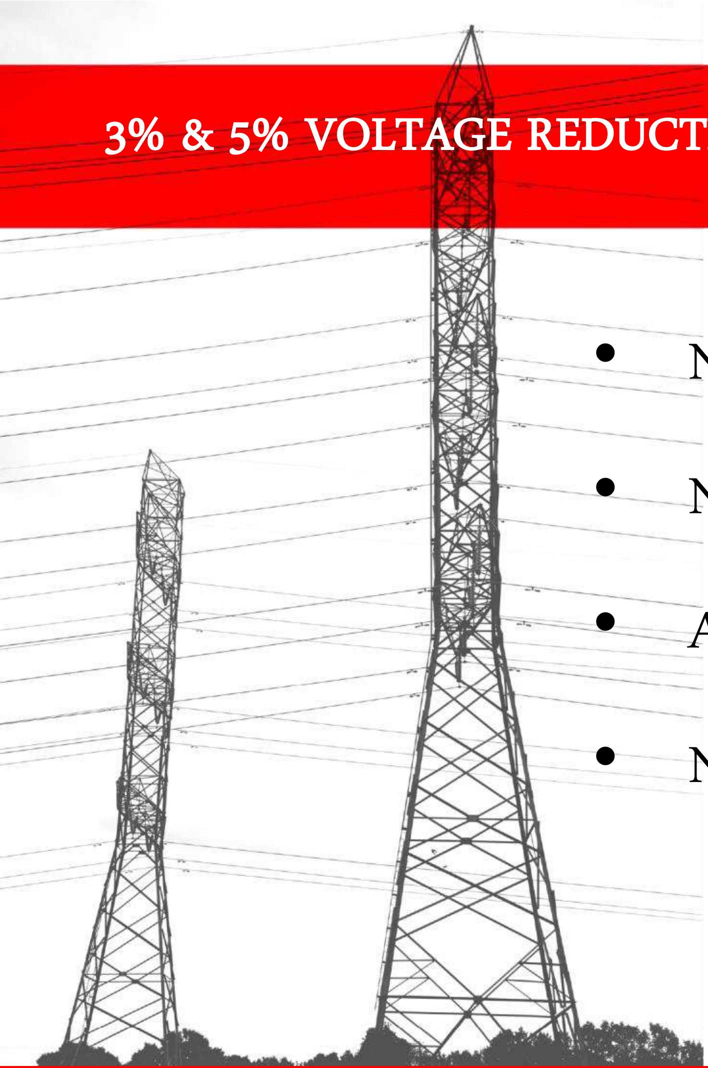
(Above) Over 40 broken poles along the route to Burks Falls DS near Huntsville were toppled over by the wind storm.

Starting at 7:30 a.m. on November 6, high winds approaching 100 km/h unexpectedly appeared in Southwestern Ontario. The storm quickly swept through the Georgian Bay area and into Northeastern Ontario. In response, Hydro One quickly mobilized over 1,200 personnel along the path of the storm. Within a few hours the storm reached its pinnacle with 112,742 Hydro One customers interrupted simultaneously.

On the first day, even with over 100 damaged poles, we were able to restore over half of the customers who lost power. Cottage country was the hardest hit area with multiple interruptions, including the toppling of over 40 poles near Huntsville. To further assist restoration efforts, Hydro One reached out to its many mutual assistance partners who sent crews to help restore power.

Hydro One and assisting LDCs continued to work through the weekend to restore customers. As Monday approached, the bulk of the affected customers had been restored, however many water access and seasonal customers remained without power. The clean-up continued into Tuesday morning, giving crews a short break before a new predicted storm arrives this weekend.

3% & 5% VOLTAGE REDUCTION(AUG 9 2016)



- Number of Broken Poles: 101
- Number of Transformers: 32
- Amount of Conductor: 9,200 meters
- Number of Cross Arms: 51

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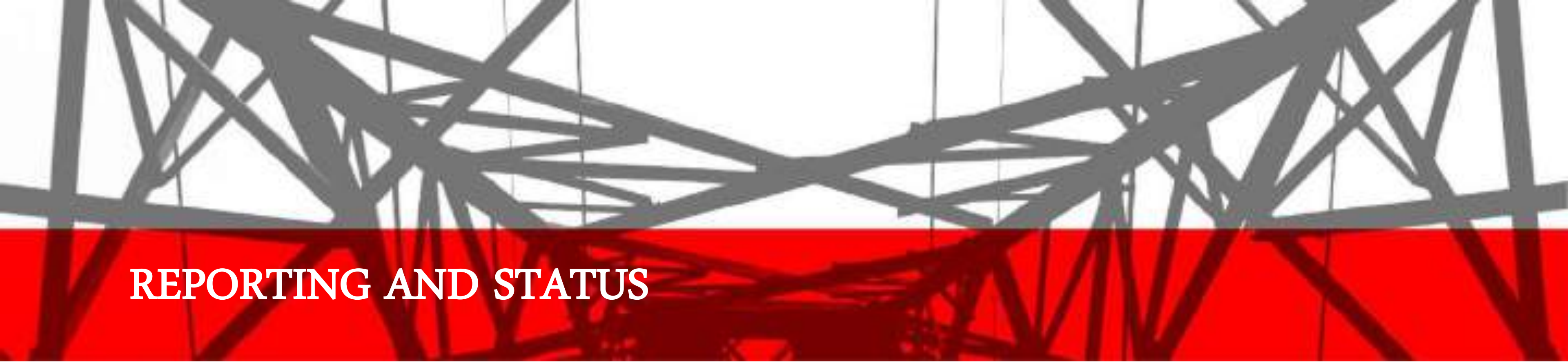
68

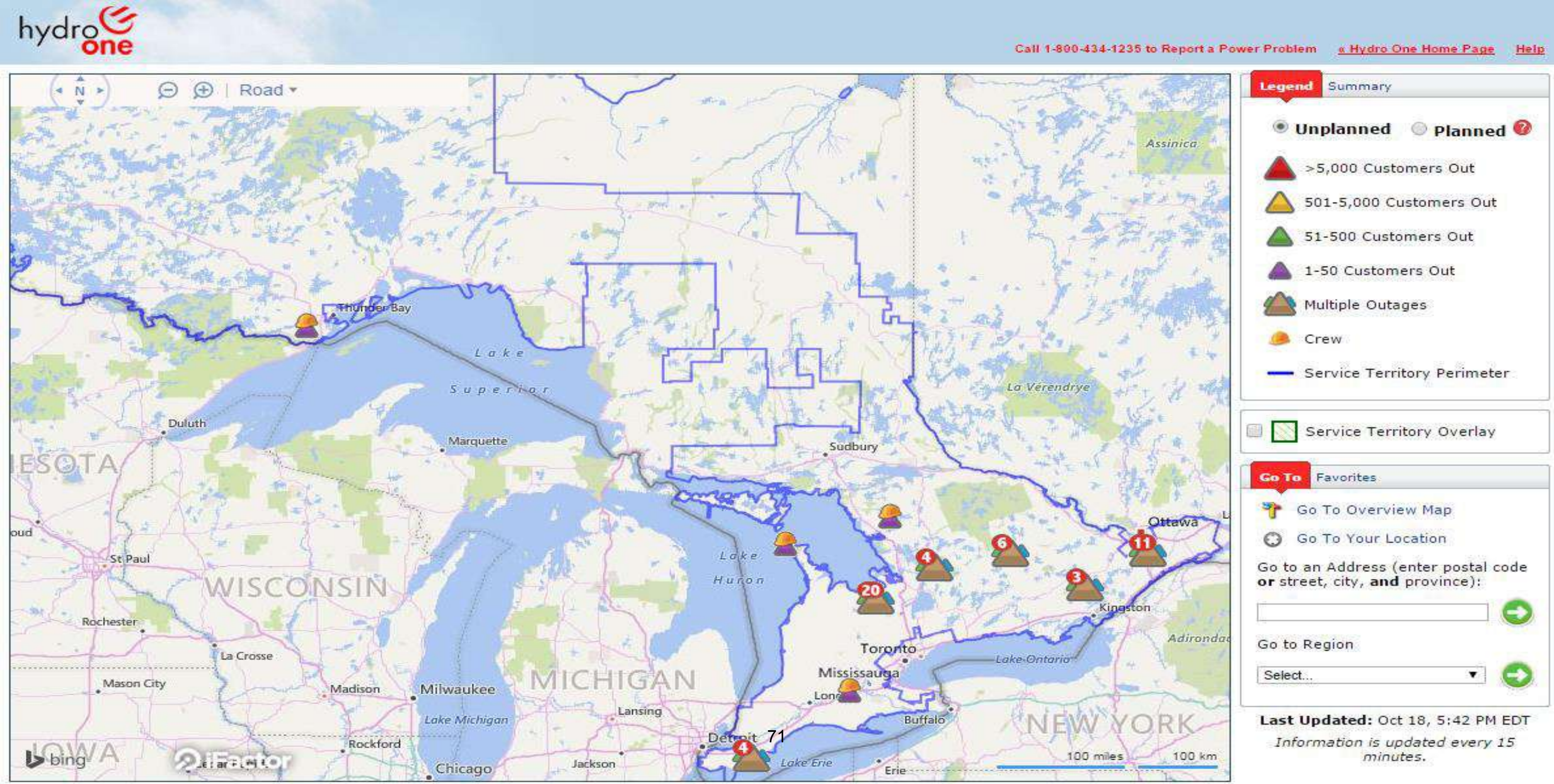

Lights out?
Find out when we'll get them
back on for you. Sign up now...



REPORTING AND STATUS

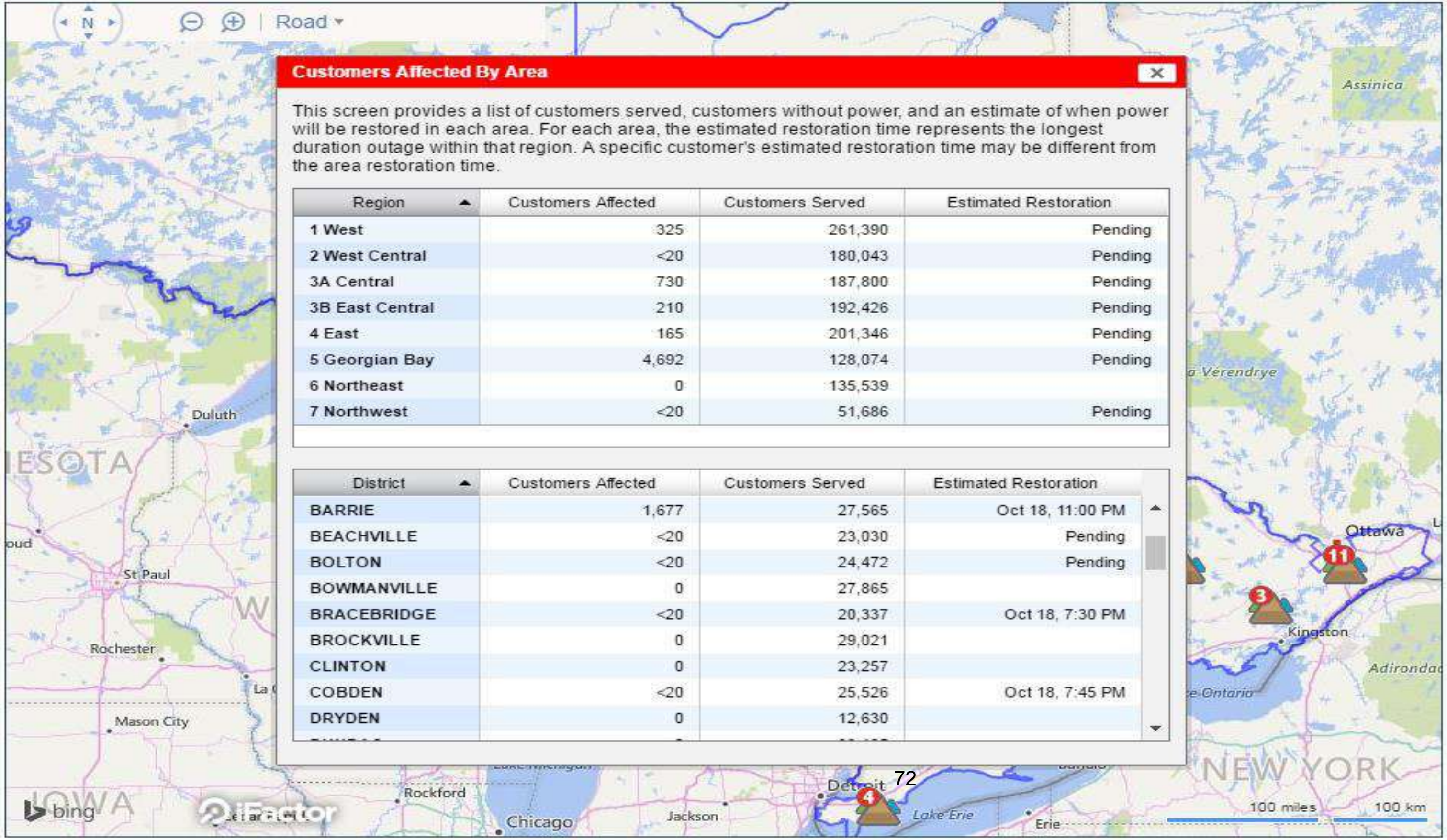
If you've lost power or want to report damage to a hydro line call 1-800-434-1235. You can also access Hydro One's power outage map to find out where crews are working on restoring power in a region, how many people are impacted, and the estimated restoration time by accessing at:

http://www.hydroone.com/StormCenter3/


hydro one
Call 1-800-434-1235 to Report a Power Problem
« Hydro One Home Page
Help
Road
Legend
Summary
Unplanned
Planned
>5,000 Customers Out
501-5,000 Customers Out
51-500 Customers Out
1-50 Customers Out
Multiple Outages
Crew
Service Territory Perimeter
Service Territory Overlay
Go To
Favorites
Go To Overview Map
Go To Your Location
Go to an Address (enter postal code **or** street, city, **and** province):
Go to Region
Select...
Last Updated: Oct 18, 5:42 PM EDT
Information is updated every 15 minutes.
Thunder Bay
Lake Superior
Duluth
Marquette
Sudbury
Lake Huron
Ottawa
Kingston
Toronto
Mississauga
Lake Ontario
Buffalo
Lake Erie
Erie
Detroit
Lansing
Jackson
Milwaukee
Lake Michigan
Chicago
Madison
Rockford
La Crosse
Mason City
Rochester
St Paul
WISCONSIN
MICHIGAN
NEW YORK
IOWA
Assinica
La Vérendrye
Adirondac
100 miles
100 km
bing
20
11
6
4
3
4

hydro one

Call 1-800-434-1235 to Report a Power Problem | « Hydro One Home Page | Help



Customers Affected By Area

This screen provides a list of customers served, customers without power, and an estimate of when power will be restored in each area. For each area, the estimated restoration time represents the longest duration outage within that region. A specific customer's estimated restoration time may be different from the area restoration time.

Region	Customers Affected	Customers Served	Estimated Restoration
1 West	325	261,390	Pending
2 West Central	<20	180,043	Pending
3A Central	730	187,800	Pending
3B East Central	210	192,426	Pending
4 East	165	201,346	Pending
5 Georgian Bay	4,692	128,074	Pending
6 Northeast	0	135,539	
7 Northwest	<20	51,686	Pending

District	Customers Affected	Customers Served	Estimated Restoration
BARRIE	1,677	27,565	Oct 18, 11:00 PM
BEACHVILLE	<20	23,030	Pending
BOLTON	<20	24,472	Pending
BOWMANVILLE	0	27,865	
BRACEBRIDGE	<20	20,337	Oct 18, 7:30 PM
BROCKVILLE	0	29,021	
CLINTON	0	23,257	
COBDEN	<20	25,526	Oct 18, 7:45 PM
DRYDEN	0	12,630	

Legend | **Summary**

Outage Details

Outages by Area

Active Outages: 55
Affected Customers: 6,125

Service Territory Overlay

Go To | Favorites

Go To Overview Map

Go To Your Location

Go to an Address (enter postal code **or** street, city, **and** province):

Go to Region

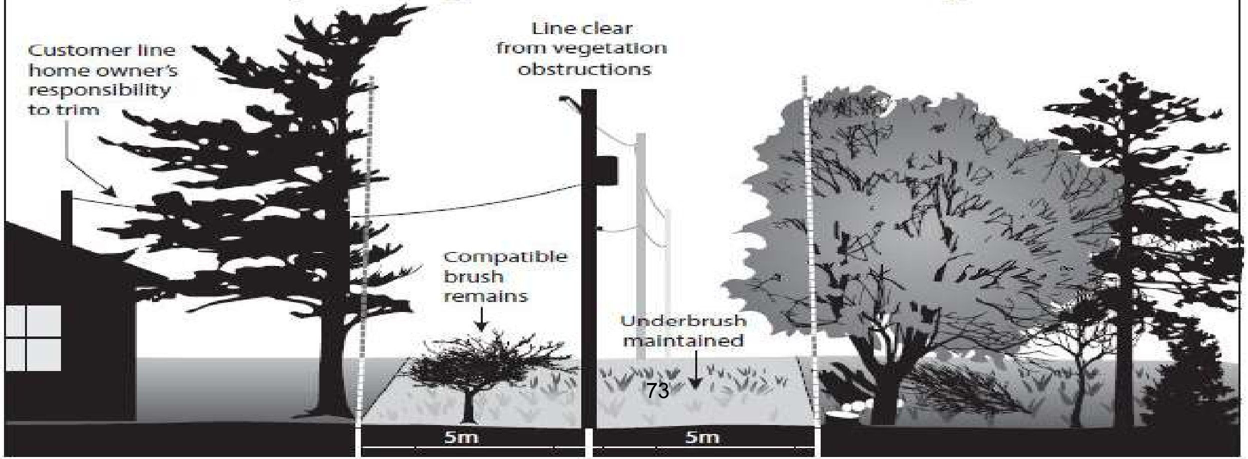
Select...

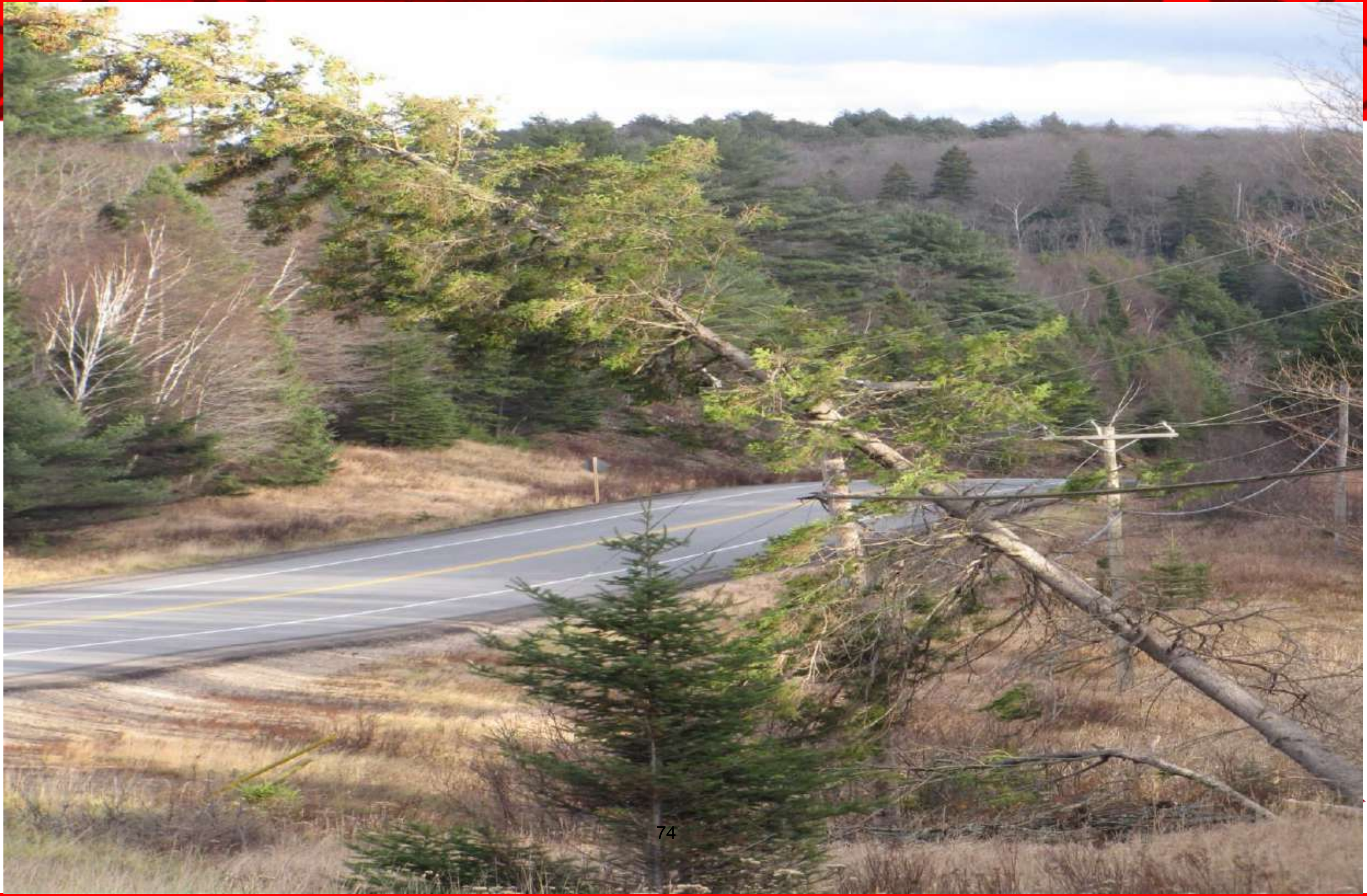
Last Updated: Oct 18, 5:42 PM EDT

Information is updated every 15 minutes.

Example of Line Requiring Vegetation Maintenance

Example of Vegetation Maintenance Completed

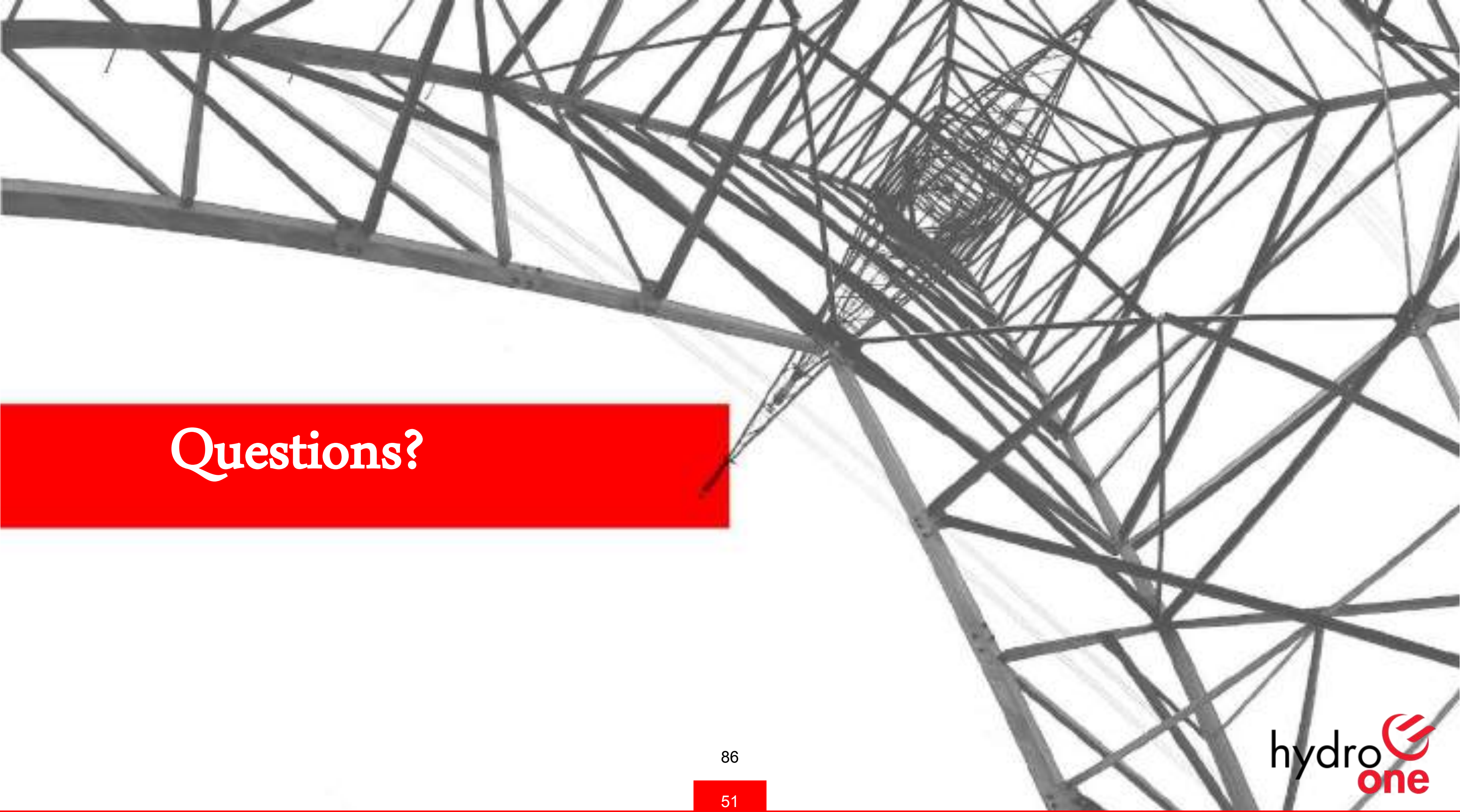




80

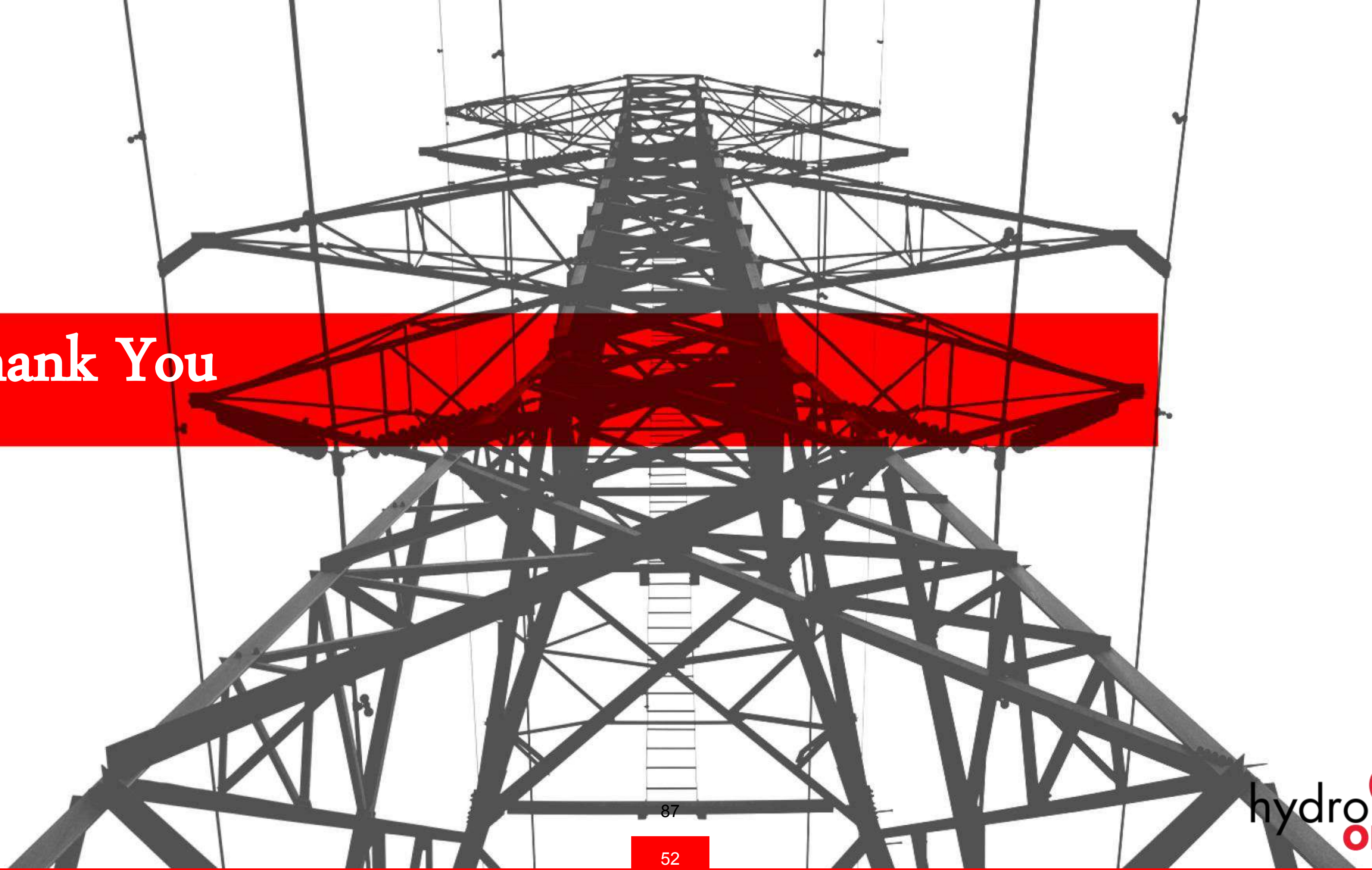



THE NIAGARA FALLS POWER CO.



Questions?

Thank You



Managing Costs and the Conservation First Framework

Hydro One Networks Inc.: Large Customer Conference

Alexandra Campbell, Director, Alliances and Marketing

November 22, 2016

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Independent Electricity System Operator

Today's Agenda

- Who is the IESO?
- Ontario Planning Outlook
- Global Adjustment
- Ontario's Conservation Landscape
  - Past Performance
  - 2015-2020 Conservation First Framework

Who We Are and What We Do

The Independent Electricity System Operator (IESO) – ensuring there is enough power to meet the province's energy needs in real time while also planning and securing energy for the future. It does this by:

- Long term and short term planning
- Enabling conservation by overseeing funding of Save on Energy programs offered by LDCs
- Ensuring supply through contracts, real time energy and operating reserve market and ancillary services such as regulation and blackstart
- Operating the IESO-controlled grid
- Engaging stakeholders and communities

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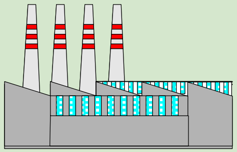
Responsibilities

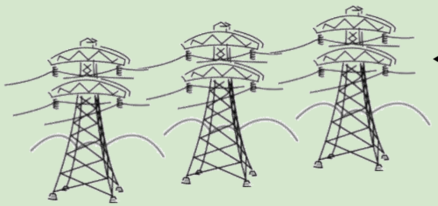
IESO Market Participants

91
Direct Connect Customers



Large use facilities
(over 5000kW)

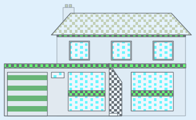
4
Transmitters



79
Generator
Market Participants

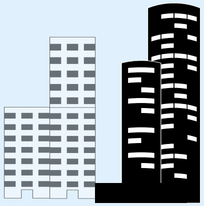
~71 Local Distribution Companies Serving

~4,400,000
Residential Customers



~430,000
General Service
Customers (< 50 kW)

~57,000
Large General
Service Customers
(> 50 kW to 4,999 kW)



57
Energy traders
(import/export market)

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System Operator

Ontario at a Glance

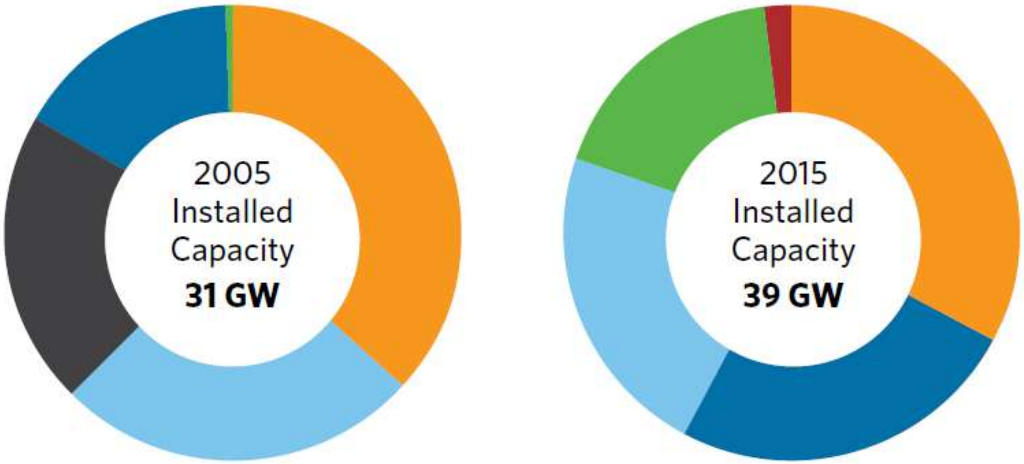
Installed Capacity	35,221 MW (December 2015)
Record Summer Peak	27,005 MW (August 1, 2006)
Record Winter Peak	24,979 MW (December 20, 2004)
Total Annual Energy Consumed	137 TWh (2015)
Energy Savings Through Conservation (2011-2014)	6,553 gigawatt-hours (GWh)
Customers	4.9 million
Ontario Import Capability	4,800 MW
Transmission Lines	30,000 km
Interconnections	New York, Quebec, Manitoba, Michigan, Minnesota

The IESO is the reliability coordinator for Ontario and works closely with other jurisdictions to ensure energy adequacy across North America.

Installed Capacity: then and now

- Changes over the last decade have:
  - Over six GW of installed coal-fired capacity was replaced with over 14 GW of renewable, natural gas-fired, nuclear and demand response resources
  - Reduced greenhouse gas emissions in Ontario's electricity sector by more than 80 percent
  - Ensured Ontario's electricity needs will be met well into the next decade, with current planned investments

Figure 1: Ontario Installed Supply Mix in 2005 and 2015



2005		2015	
Nuclear	37%	Nuclear	33%
Water	26%	Natural Gas	25%
Coal	21%	Water	22%
Natural Gas	16%	Solar/Wind/Bioenergy	18%
Solar/Wind/Bioenergy	<1%	Demand Response	2%

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IESO's Ontario Planning Outlook

The report can be found on the main page of the IESO's website @ ieso.ca

- The Ontario Planning Outlook provides a 10-year review (2005-2015) and a 20-year outlook (2016-2035)
- It is one of the technical documents being used for the Ministry's consultation process on the Long Term Energy Plan

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Net Energy Demand Across Demand Outlooks

Four Outlooks

— Outlook A

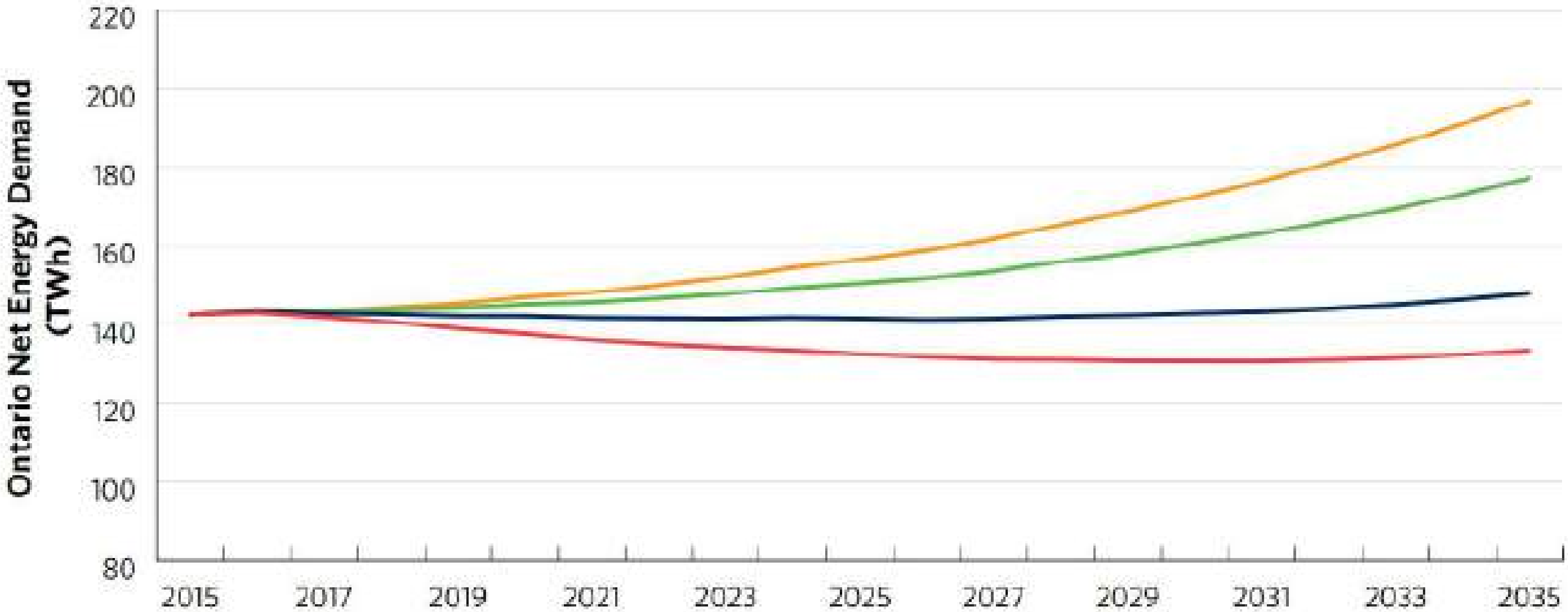
(or low demand outlook), which explores the implications of lower electricity demand

— Outlook B

(or flat demand outlook), which explores a level of long-term demand that roughly matches the level of demand that exists today

— Outlook C — Outlook D

(or higher demand outlooks), which explore higher levels of demand driven by different levels of electrification associated with policy choices on climate change



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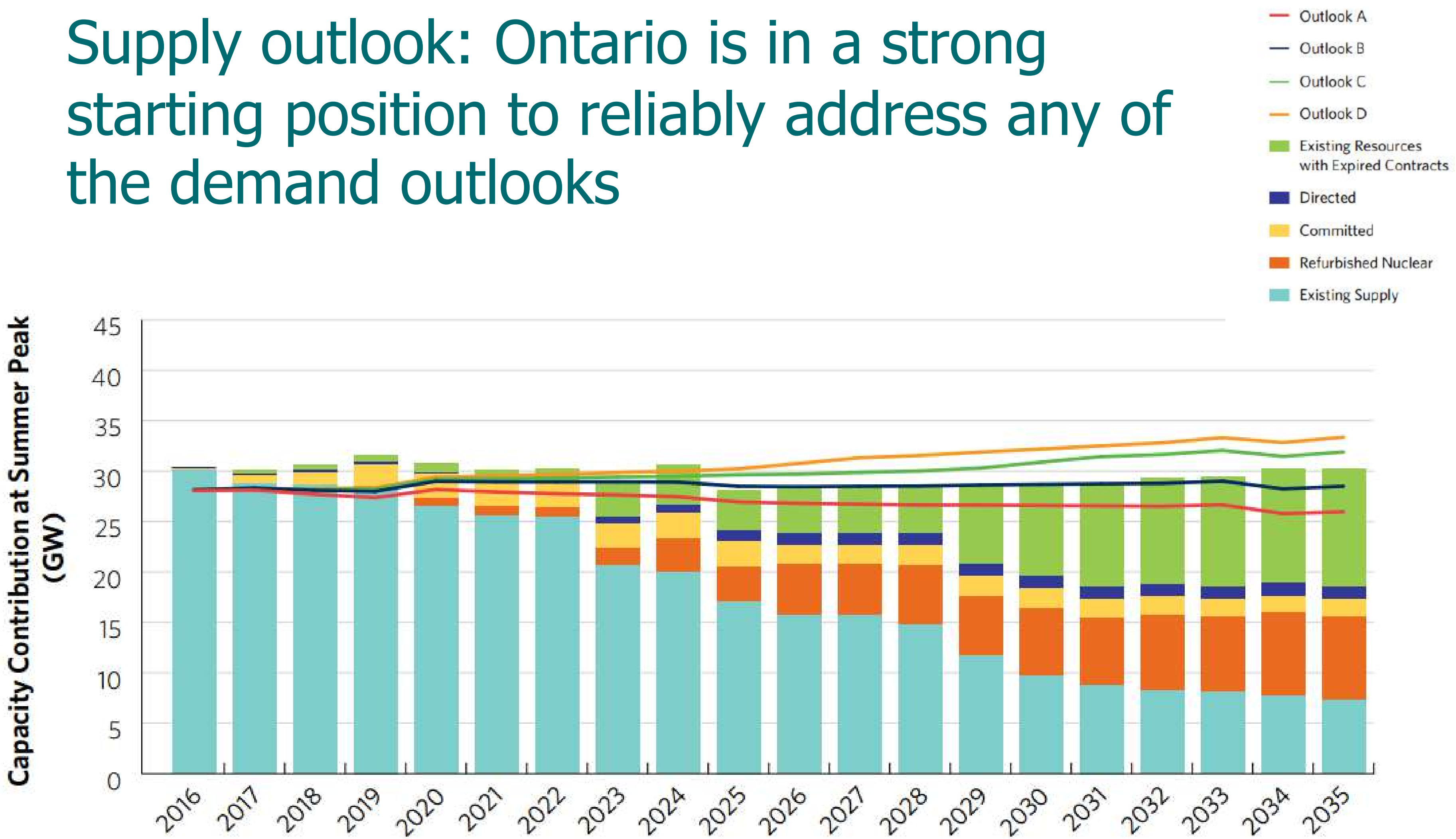
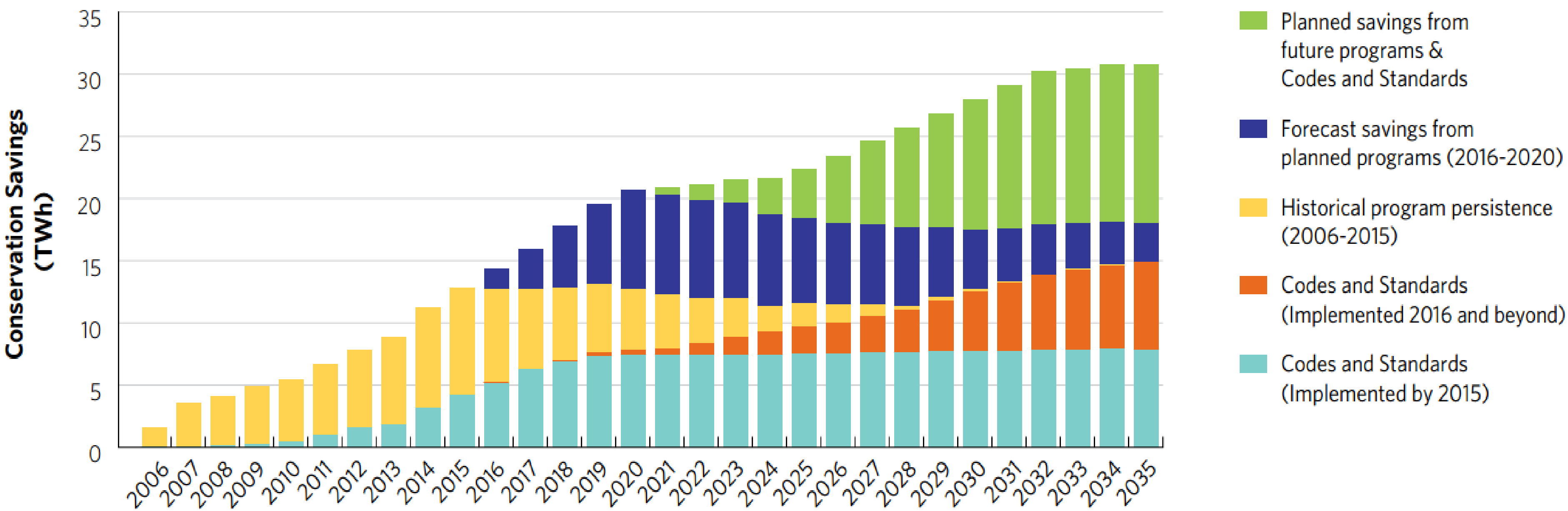
Supply outlook: Ontario is in a strong starting position to reliably address any of the demand outlooks



Conservation Outlook

- All four outlooks reflect achievement of LTEP 2013 conservation targets and the Conservation First Framework



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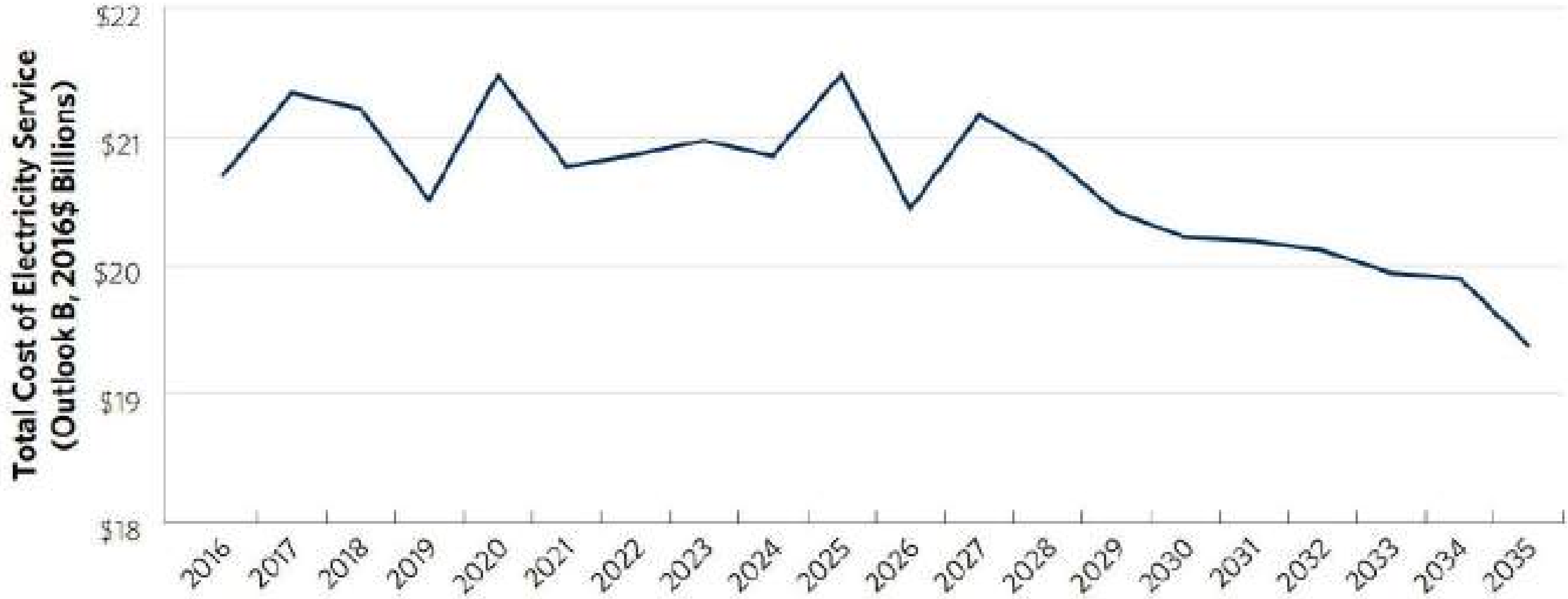
Total Cost of Electricity Service in Outlook B



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Wholesale Market Price and Global Adjustment

Wholesale Price (HOEP)

- Signals current supply and demand situation
- Covers operational costs of production – such as fuel
- Varies by hour and impacted by weather, time of day, year or day of the week

Global Adjustment

- Investment or capacity costs to build or refurbish infrastructure – that are not covered through market revenues
- Includes contracts, and regulated rates to generators and other suppliers as well as conservation
- Generally speaking, when the HOEP is lower, then the GA is higher in order to cover all system costs.
- The GA also changes when new projects come into service, contract payments take effect or as a result of charges in demand

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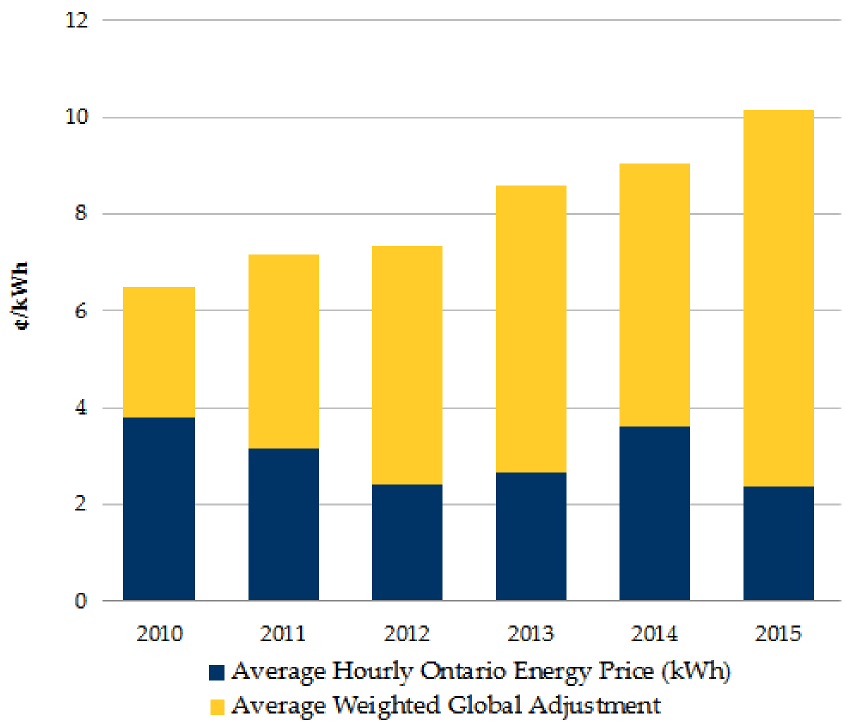
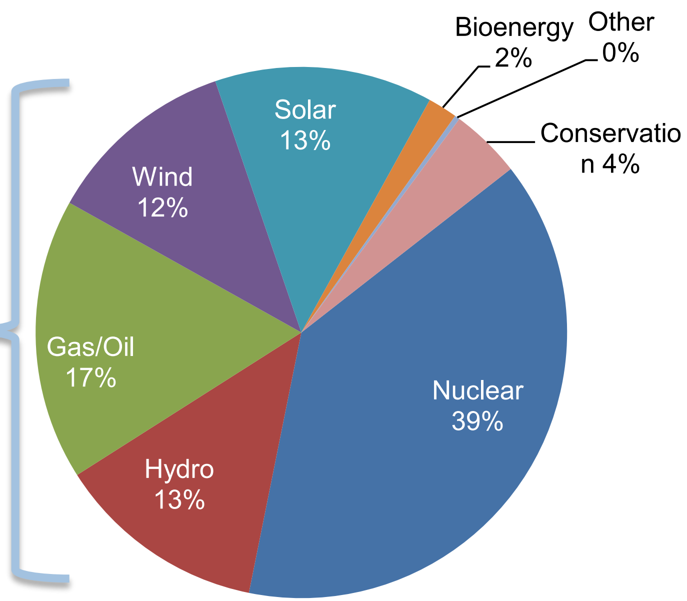
Electricity Pricing Trends and Global Adjustment Contributors





2015 Global Adjustment by Fuel Source

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Why is the Global Adjustment high lately?

- The primary reason is that the wholesale market price for electricity is currently very low, largely reflecting low natural gas fuel costs
- As a result, resources earn less from the wholesale market and require a greater contribution from Global Adjustment to ensure they are made whole on their contracts
- The opposite can also be true. Recall earlier in the spring when market prices were high (high gas prices), actual Global Adjustment costs were a small credit to consumers

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How long will the Global Adjustment last?

- In Ontario wholesale market revenues are insufficient to sustain the level of investment required to maintain a reliable electricity system that consumers expect
- As such, some form of out-of-market payment mechanism such as Global Adjustment, is required to ensure reliability and pay for new investments
- The IESO is currently looking at ways to bend the electricity cost curve through the implementation of a capacity auction and other approaches to reduce costs that would otherwise have been included in Global Adjustment

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Industrial Conservation Initiative Overview

- Most customers pay global adjustment based on the amount of electricity they consume in a month (kWh). They are referred to as **Class B**.

- **Class A** consumers pay global adjustment based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period. ICI requirements are established in Ontario Regulation 429/04

ICI threshold changes over the years:

- **2010** - ICI introduced to customers with peak demand greater than 5 MW
- **Spring 2014** - expanded to include customers with a peak demand above 3MW and less than or equal to 5 MW (with certain NAICS required)
- **September 2016** - government proposed expansion to the ICI threshold to include consumers >1MW and remove the NAICS restrictions on 3-5MW group

Calculating GA for Class A Customers

- A Class A customer's PDF is used to calculate monthly GA charges during the adjustment period
- This is done by multiplying the monthly, Ontario-wide total GA costs (both Class A and Class B totals) by the customer's PDF
  - E.g. The system-wide GA costs for February 2016 were $1063.7 M. Using the PDF in the earlier example:

    $1063.7 M x **0.00017378** = $184,849.79 (customer's GA charge for February 2016)

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
GA-OEFC-NUG (M$)	74.2	73.3	76.5	61.2								
GA-OPG (M$)	327.9	339.6	378	335.1								
GA-OPA (M$)	668.5	650.8	665.6	694.4								
Total GA (M$)	1070.6	1063.7	1120.1	1090.7								

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Peak Calculation

- The top five hours of peak demand in a year are those occurring on different days in which the greatest number of MW of electricity was withdrawn from the IESO-controlled grid by all market participants in Ontario.

- They are established after the end of the base period by the IESO and posted on the IESO's website at http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx.

Base Period: May 1, 2014 to April 30, 2015

Date	Hour Ending	Allocated Quantity of Energy Withdrawn (MW)	Embedded Generation (MW)	Total (MW)*
January 7, 2015	19	21,118.57	491.570	21,610.14
February 19, 2015	20	20,976.23	440.031	21,416.30
August 26, 2014	17	20,967.23	682.792	21,650.03
February 23, 2015	20	20,862.40	539.973	21,402.37
September 5, 2014	17	20,830.89	884.740	21,715.63

*The value in the Total (MW) column is the number used to calculate a customer's Peak Demand Factor.

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ICI Timing

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014					BASE PERIOD							
2015					OPT IN/ OUT		ADJUSTMENT PERIOD					
2016												

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Calculating Peak Demand Factor

Peak	Day	Hour	Customer's Consumption (MWh/h)		Peak System Consumption (MWh/h)*	
1	Jul 28, 2015	HE 17	3.1		23,023.710	
2	Jul 29, 2015	HE 17	4.4		22,835.441	
3	Aug 17, 2015	HE 17	3.9		22,892.239	
4	July 27, 2015	HE 18	4.1		22,323.277	
5	Sep 3, 2015	HE 14	4.3		22,860.233	
			Total = **19.8 MW/h**	÷	Total = 113,934.900 **MW/h**	**PDF = 0.00017378**

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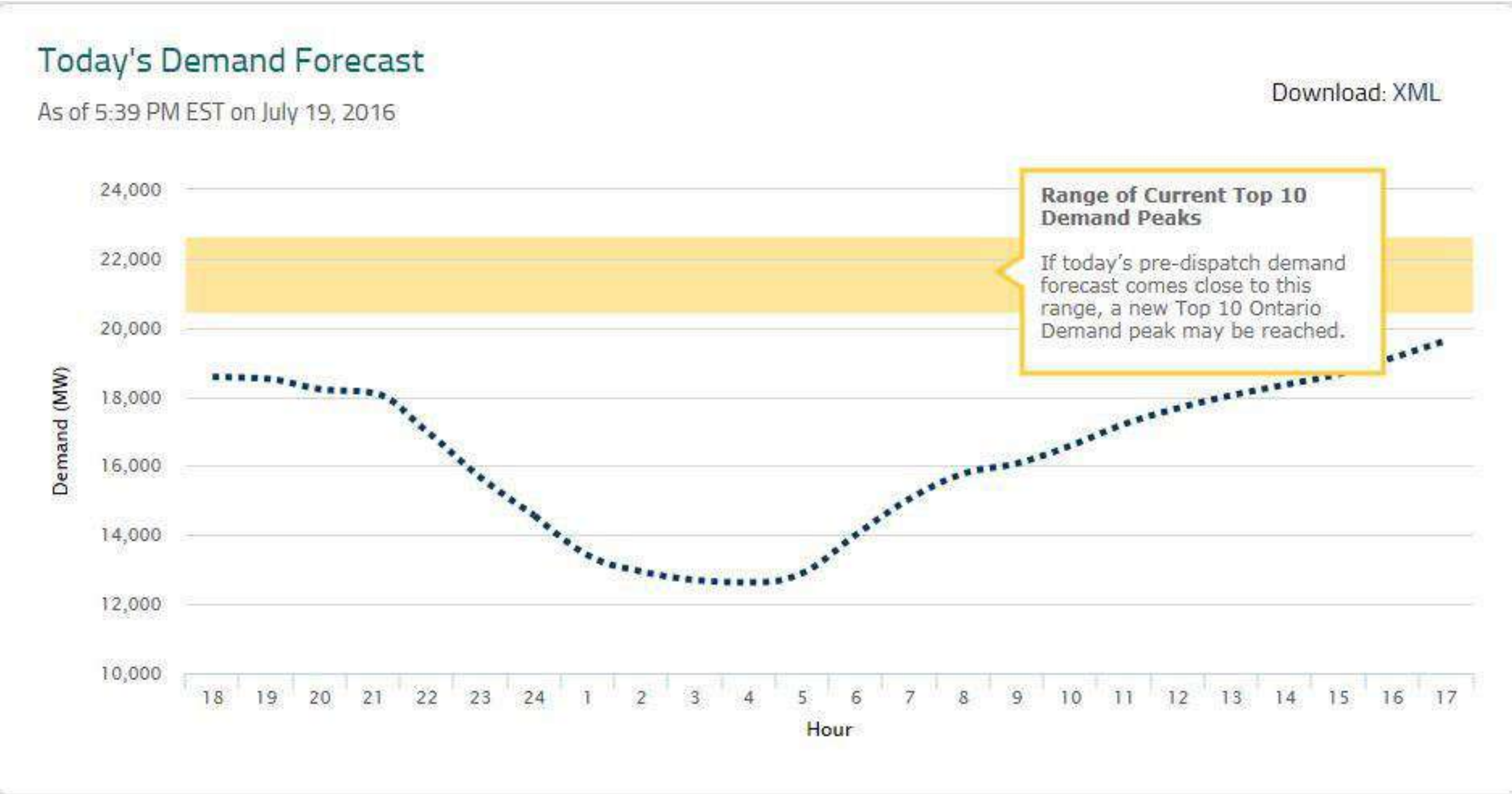
www.ieso.ca/peaktracker



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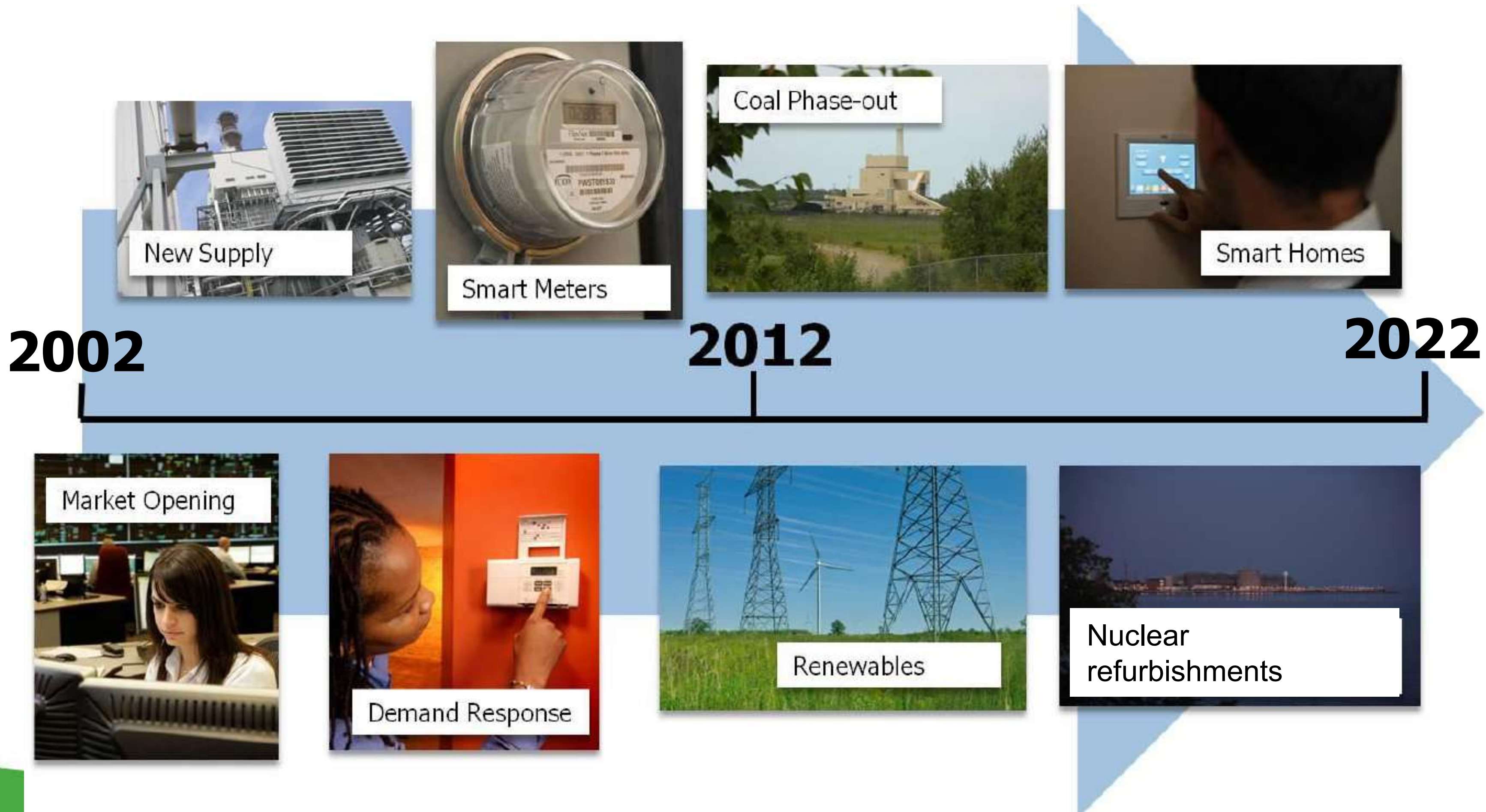
Two Decades of Change



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Long Term Conservation Goals

Almost all electricity demand growth to 2032 to be met by energy efficiency & improved codes and standards

Goals:
8.7 TWh in 2020;
30 TWh in 2032

Demand Response to meet 10% of peak demand by 2025

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Putting Conservation First

- Conservation provides the **cleanest and most cost-effective** alternative to new generation at less than 4 cents/kWh
- Conservation lowers peak demand, deferring or avoiding the need to build new infrastructure
- Helps Ontarians better manage their energy costs
- Favourable return on investment for customers

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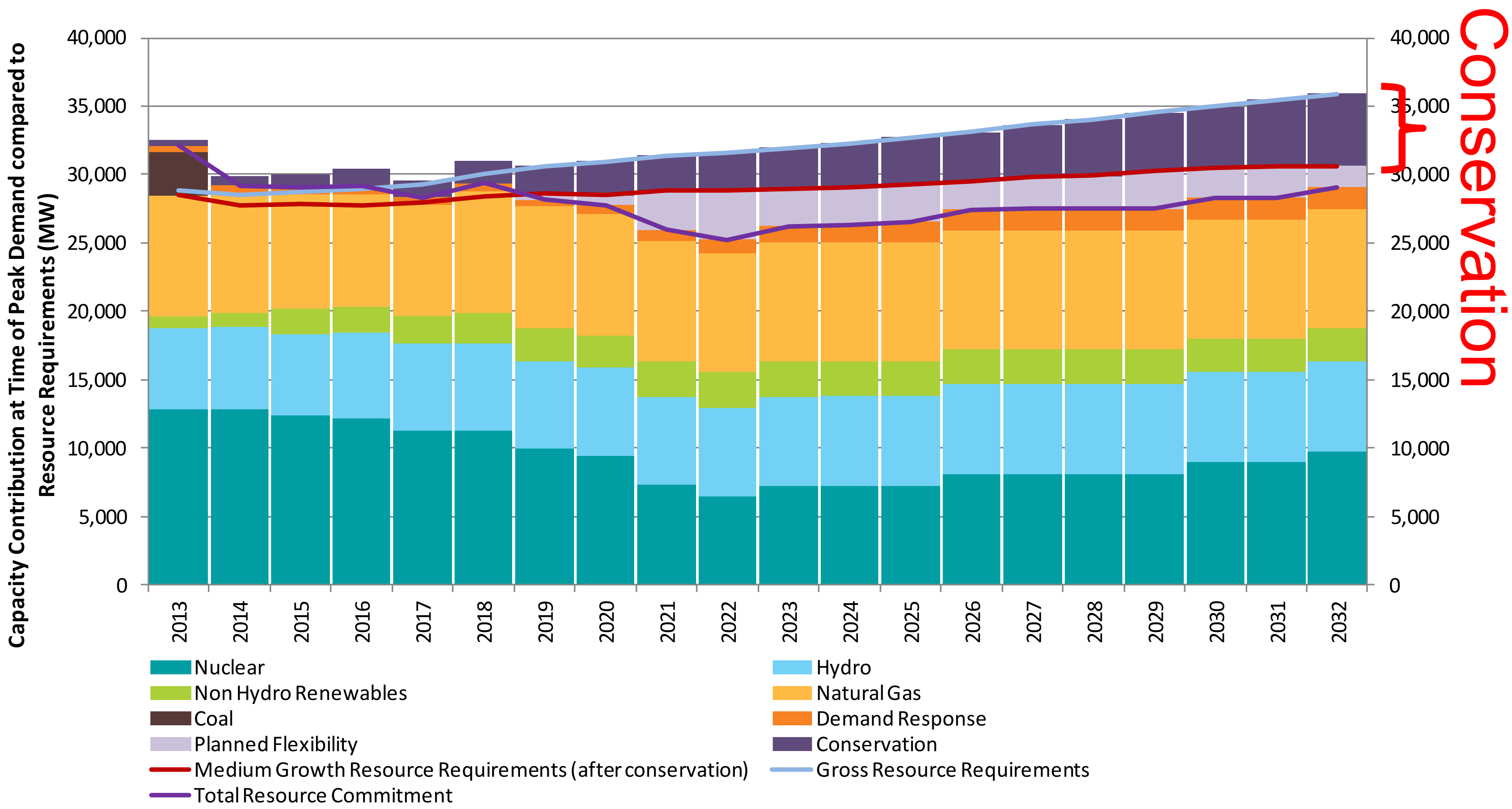
Impact of Conservation in Energy Planning



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Conservation Success in Ontario

saveONenergy

2011 TO 2014

416,000 Inefficient Appliances Collected Since 2006

6,400 GWh In Electricity saved from 2011 to 2014 Across Ontario

9.9 Million Energy Saving Products Purchased With saveONenergy Coupons

2,100 Energy Audits

81,000 Small Business Direct Install Lighting Projects

30,000 Retrofit Projects

Customers invested over $2 billion into Conservation Programs and saved over $4 billion in avoided costs

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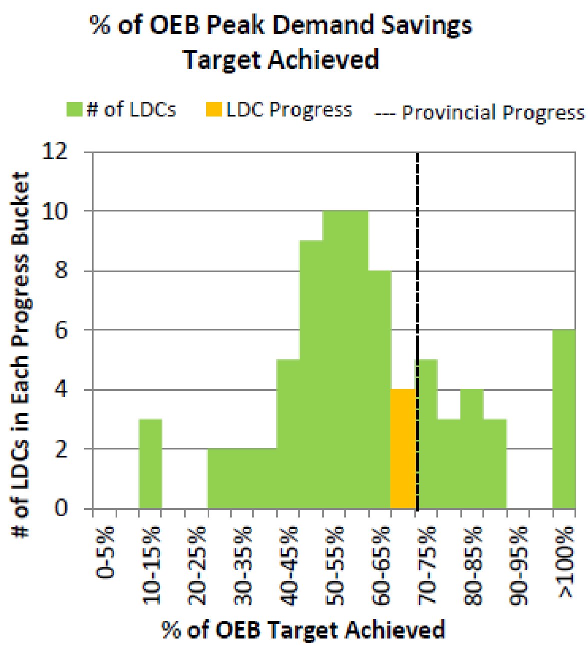
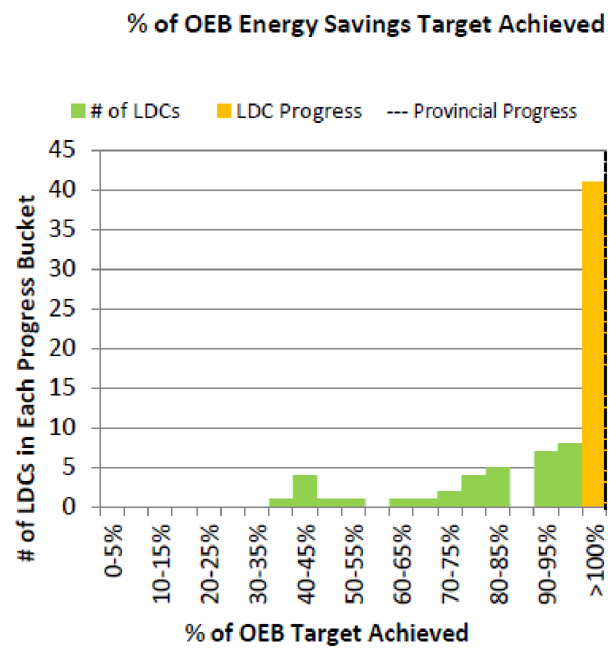
Collectively, LDCs Exceeded 2011-2014 Energy Savings Target

- 70% (928 MW) of full Peak Demand Target (1,330 MW) achieved
- 109% (6,553 GWh) of full Energy Target (6,000 GWh) achieved





Based on Final 2011 -2014 Verified Results, *Results presented at the end-user level .*

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Conservation First Framework *At a Glance*

- 7 TWh of energy savings by end of 2020
- $2.2 billion over a six-year term, administered by IESO
  - $1.8B for LDC Delivery Costs
  - $0.4B for Central Services Costs
- Evolving IESO-LDC relationships
- $500 million Industrial Accelerator Program, targeting 1.7 TWh reduction, delivered by IESO to transmission-connected customers
- LDC CDM 6-yr plans support consideration of CDM in local/regional planning

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Conservation First Framework Focus

- The new Conservation First Framework is focused on:
  - Providing electric utilities with long-term **stable funding** and budgets
  - **Cost-effective** electric utility conservation plans
  - Greater electric **utility autonomy**
  - Making **province-wide programs** available for delivery
  - Flexibility to align conservation programs to **local needs**
  - **Streamlined approvals** and administrative requirements
  - Encouraging **innovation**
  - Regional and natural gas utility **collaboration**

Conservation First Framework Roles & Responsibilities

IESO

- **Provide LDCs with funding options for CDM programs**
- **Provide program design and delivery support for LDCs**
  - Funding for local/regional pilots
  - Capability building initiatives
  - Funding for collaboration activities between LDCs
- **Conduct mid-term review including new conservation Achievable Potential Study**
- **Conservation with large industrials connected to the transmission grid**
- **Existing/planned centrally delivered initiatives:**
  - Energy Managers for multi-site customers
  - Province-wide pay-for-performance program for multi-site customers
  - Province-wide whole home pilot program for residential customers

LDCs

- **Develop and implement a CDM Plan to meet target over six years**
- **Design and deliver CDM programs**
- **Deliver programs cost-effectively**
  - Exceptions for low-income and on-reserve First Nation customers, as well as education programs

2015 and 2016 Achievements

Highest annual energy savings to date achieved in 2015

Fourth consecutive year of increased energy savings results

- LDCs achieved 1.1 TWh of net annual energy savings that persist to 2020 (or 1.2 TWh of net first year energy savings) in 2015
    - Residential sector: 233 GWh (21%)
    - Business sector: 884 GWh (79%)
- Over two-thirds of LDCs exceeded 2015 forecasted savings from CDM Plan
- On track to meet the CFF 2020 Energy Savings Target

As of Q3 2016, 23% (1.63TWh) of 7TWh CFF target has been achieved

- Portfolio remains cost-effectiveness - within 4¢/kWh as of Q2 2016; only 8.6% ($157M) of $1.8B LDC CDM Plan budget spent

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New Programs - 2017

- Per the June 10, 2016 Direction from the Minister of Energy, the IESO shall, in consultation with distributors, centrally design, fund and deliver…

  "a province-wide pay-for-performance Conservation and Demand Management (CDM) program for Multi-Distributor Consumers ("Multi-Distributor Program") "

- The new programs will be funded out of the existing Conservation First Framework (CFF) Centralized Value-Added Services budget
- Energy savings achieved through program will count towards Local Distribution Company (LDC) CDM targets with savings from each participant site going to the respective LDC
- IESO shall, where appropriate, deliver program in coordination with natural gas distributors
- Implementation of program shall commence by end of Fall 2016

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Conservation Mid-Term Review

- Per March 2014 Direction, CFF mid-term review must be completed by June 1, 2018
- Between June and October 2016, IESO developed a draft plan and reviewed with and revised based on input from LDCs, MoE, IESO Stakeholder Advisory Committee
- Draft Mid-Term review engagement plan to be posted along with Terms of Reference and invitation for members for Mid Term Review Advisory Group
  - First meeting of Advisory Group to be held in January 2017
- IESO issued an Request for Proposals on October 28 for a vendor to support completion of review
- Outcomes of LTEP will be integrated into mid-term review
  - E.g. if LTEP target is adjusted, mid-term review options will look at corresponding adjustments to CFF targets

Demand Response (DR)

Provides an opportunity for customers to participate, reduce consumption and help mitigate costs

- Enables consumers to reduce their electricity consumption in response to prices and system needs
  - already has had impact on energy demand and helped reduced peaks
  - provides a valuable and cost-effective resource to the system

- What is the IESO doing with DR?
  - Demand Response Pilot Projects
  - Demand Response Auction
  - First DR auction Dec 2015; contribute 391.5 MW for 2016 summer and 403.7 MW for 2016-17 winter

IESO Resources – *Keep in Touch*

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Toll-free: 1.888.448.7777

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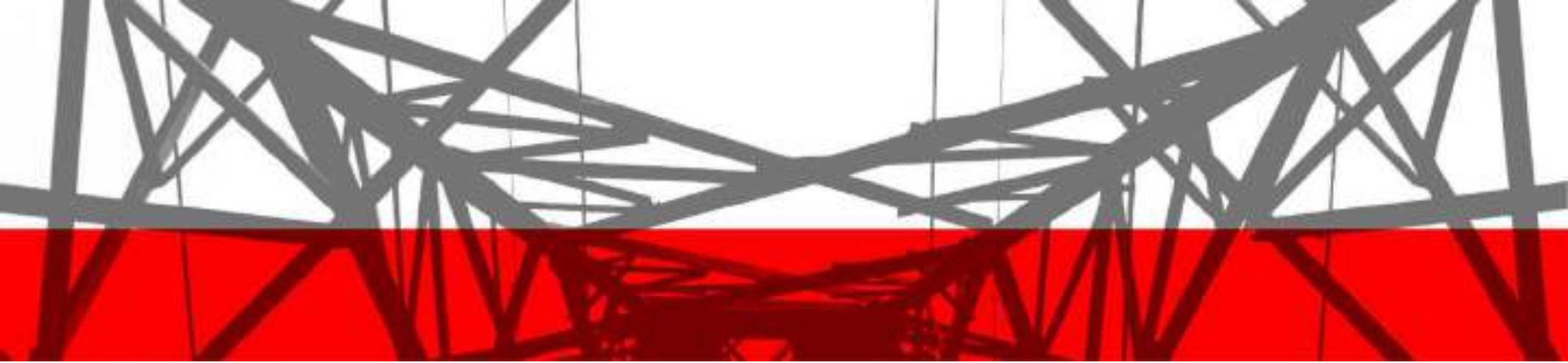
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency

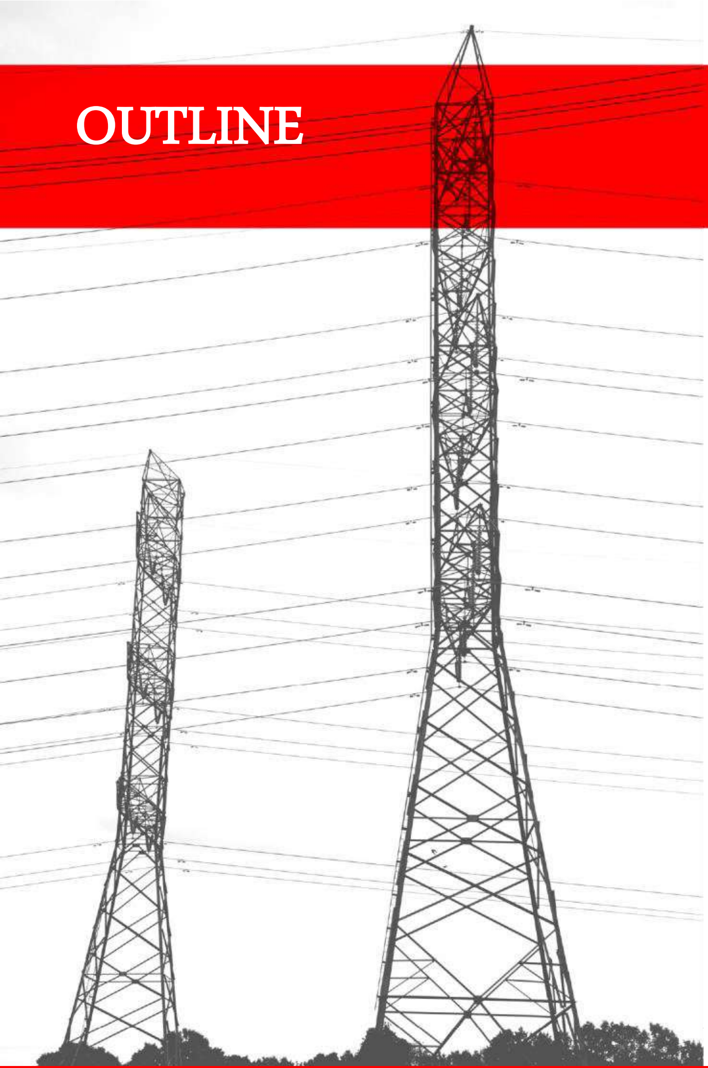


POWER QUALITY

Luis Marti

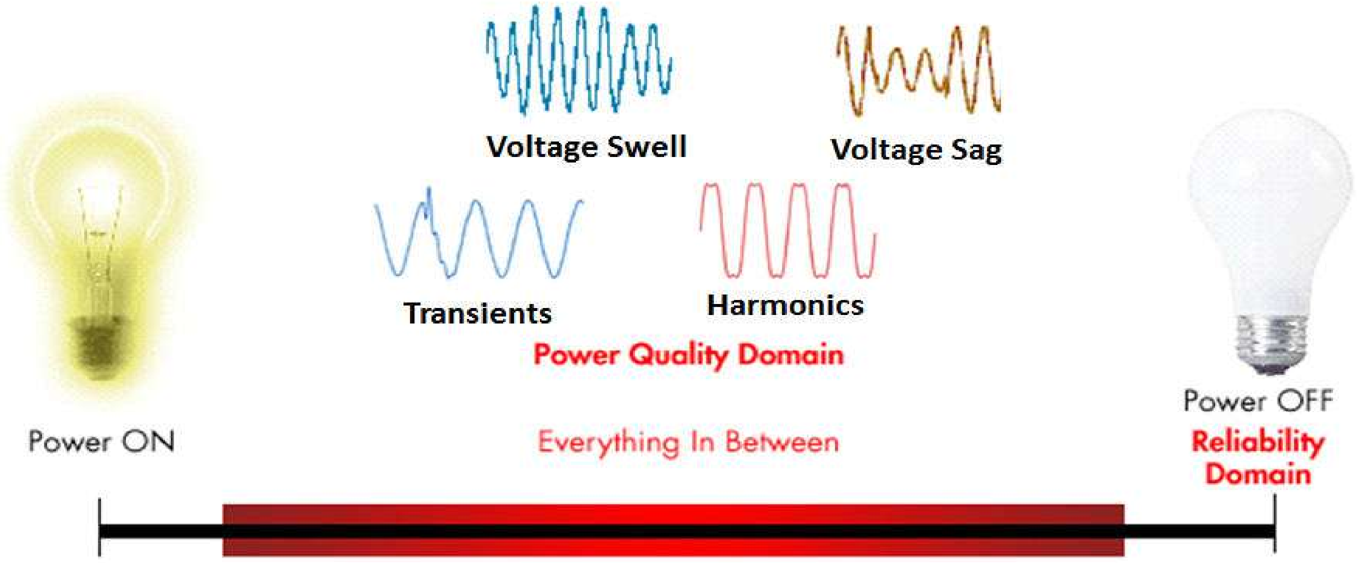
Director, Reliability Studies, Power Quality, RD&D

OUTLINE



- Power Quality vs. Reliability
  - Resiliency vs. Delivery Point Interruptions
  - Types of Power Quality issues
  - Voltage Sag
- Initiatives
  - Voltage sag reports
  - Revenue meter leverage
  - PQ audits

POWER QUALITY VS. RELIABILITY



Traditional Reliability Measures

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

POWER QUALITY

- Power Quality (PQ) is a term used to describe harmonics, flicker, voltage imbalance, transients etc., excluding Delivery Point interruptions

- Formal PQ Definition: "Any problem that is manifested in voltage, current or frequency deviations [or tripping] that result in failure or misoperation of utility or end user equipment"

- PQ events can have high cost impact for industrial customers depending on the individual plant and internal processes

- Within the Hydro One system, the most common PQ issues that affect loads are:
  - Voltage sag events
  - Transient overvoltages caused by sub-transmission capacitor bank switching. Capacitor bank switching is not an issue in transmission – IPO breakers have been used since the 90s.

- To a lesser extent:
  - Flicker
  - Harmonics

POWER QUALITY

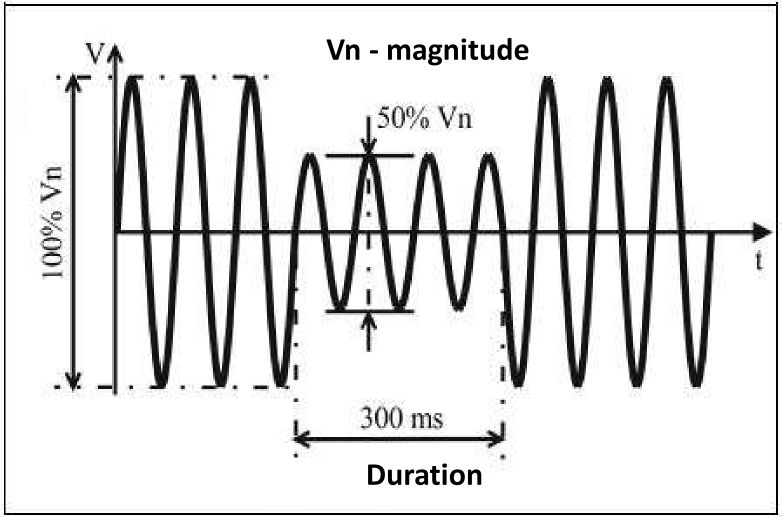
- Momentary % drop in voltage magnitude due to a fault in the system

- System dependent :“zone of influence”

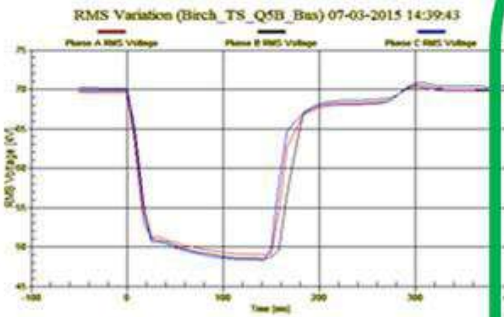
- If customer’s equipment cannot “ride through” the momentary drop in the voltage, equipment would generally disconnect automatically

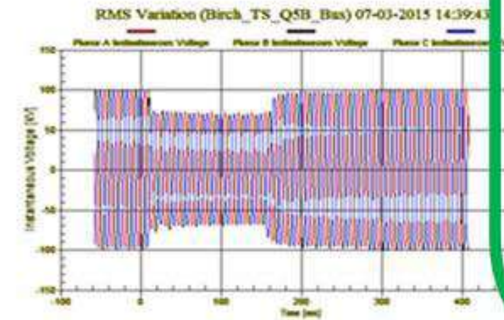
- Unlike delivery point interruptions (which are a measure of system reliability), the effects of voltage sag events are a combination of:

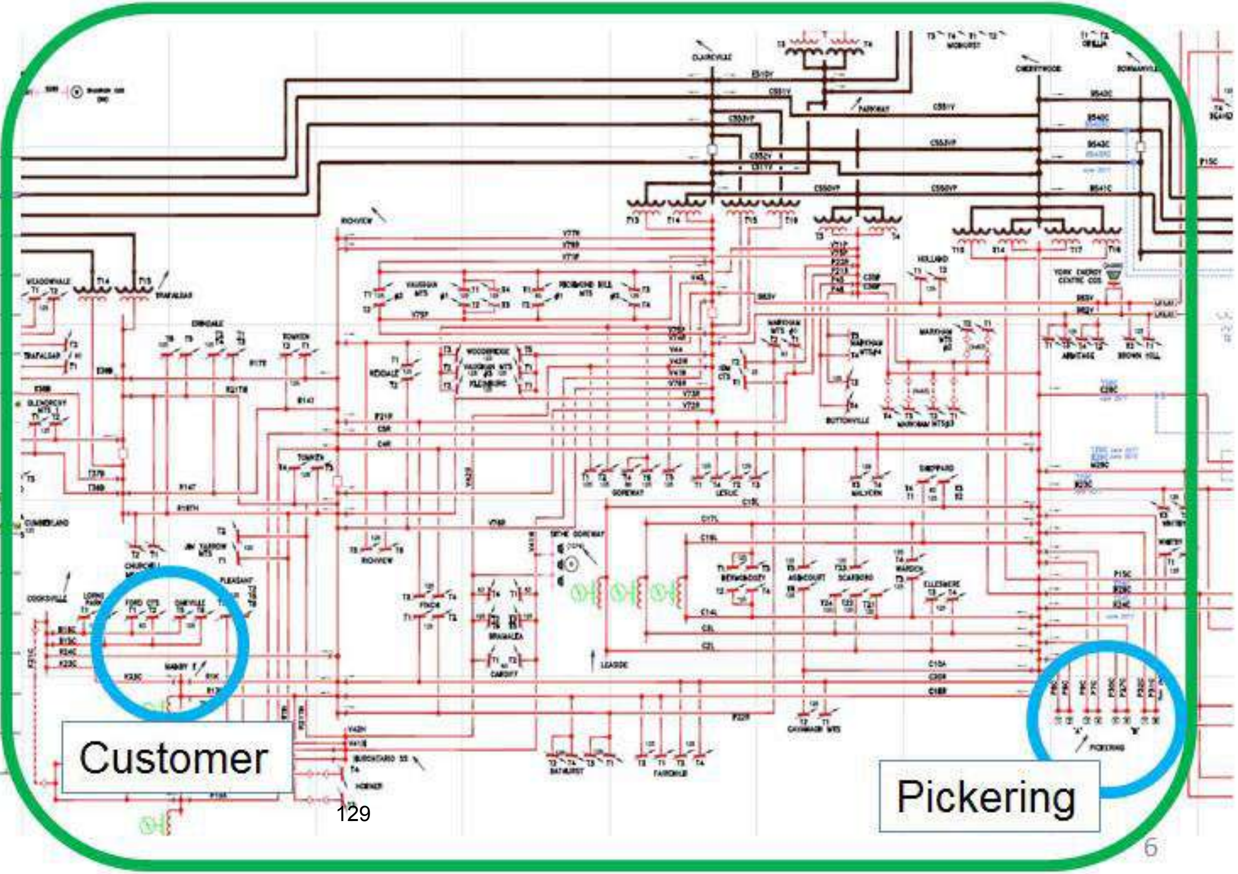
  - Severity of the sag
  - Duration of the sag
  - Resilience of the load



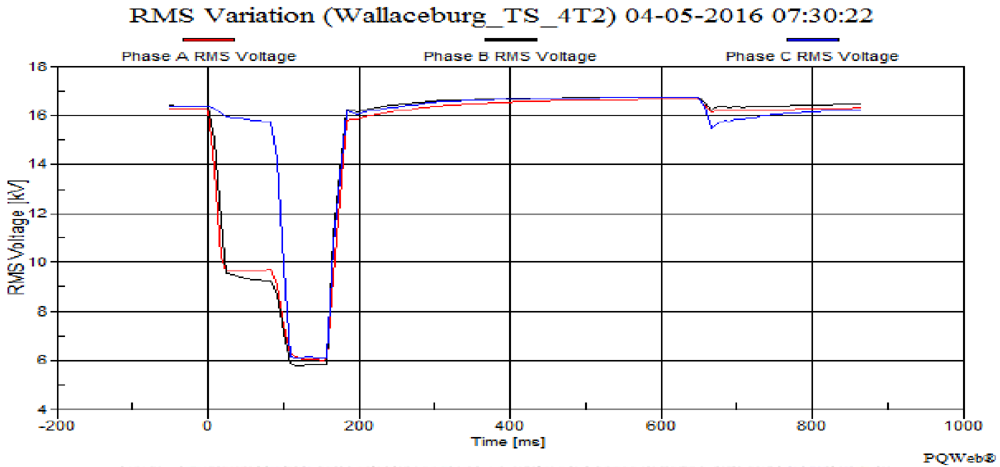
A FAULT WITHIN THE ZONE OF INFLUENCE CAN CAUSE A VOLTAGE SAG EVENT AT A CUSTOMER'S SITE

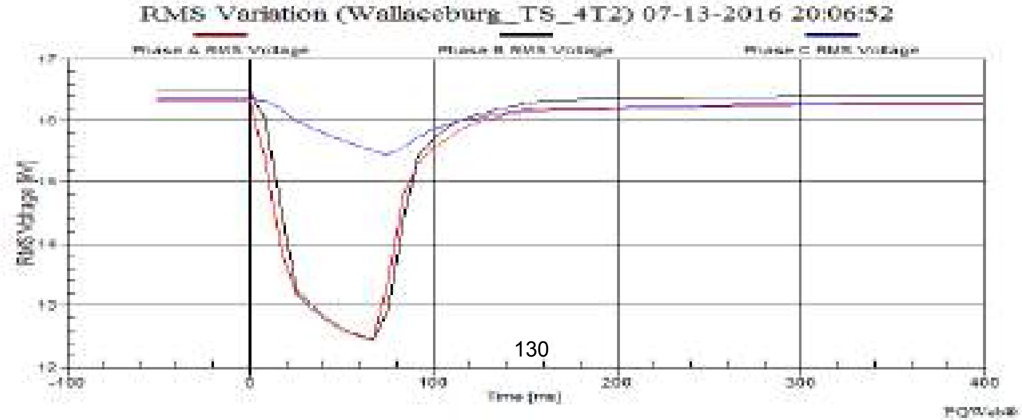






TYPICAL EVENTS CAPTURED





VOLTAGE SAG

- Standard IEEE1668 provides some guidance regarding load resilience in the form of recommended practices (not requirements / standards / compliance requirements)

- It is intended for customers to specify equipment procurement with OEMs. It carefully avoids suggesting any type of required utility / customer interface compatibility or performance

- All references to voltage sag pertain to the load side

Table 10—Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.2	10 cycles	12 cycles
2	70%	0.5	25 cycles	30 cycles
3	80%	2.0	100 cycles	120 cycles

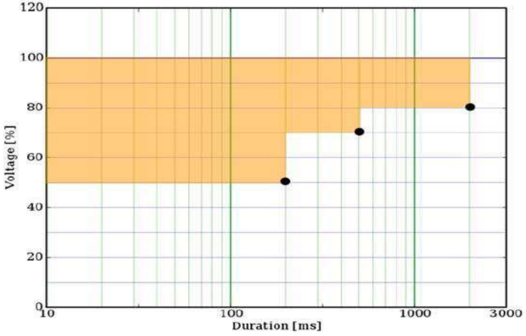


Figure 22—Recommended Type I and Type II test levels

Table 11—Recommended test points for Type III voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.05	2.5 cycles	3 cycles
2	70%	0.1	5 cycles	6 cycles
3	80%	2.0	100 cycles	120 cycles

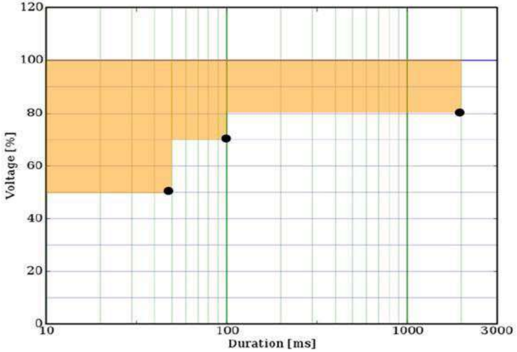


Figure 23—Recommended Type III test levels

VOLTAGE SAG (CONT'D)

- There are no metrics for the frequency of sag events for a number of reasons:
  - Sag events are logged in PQ meters but there is no way to know if the events are impactful to a customer
  - Impact of a sag event depends on the load's ride-through capability. There are no North American standards that mandate a specific level of resiliency.

- Standard IEEE1668 is a good guidance reference point

- With station PQ meters, Hydro One has no direct visibility on whether a load is affected by voltage sag issues and relies on customer-provided information to assess whether ride-through was successful or not

PQ VS. DELIVERY POINT PERFORMANCE

- Hydro One's experience is consistent with the findings of EPRI's distributive power quality study (DPQ III): voltage sags are the most common power quality event

- DPQ III showed that a facility is 8 to 20 times more likely to receive a voltage sag than an interruption

- The ratio of sags to interruptions found in the DPQ III study based on circuit type:
  - Transmission: 8 to 1 (> 100 kV)
  - Sub-Transmission: 20 to 1 (100 kV & > 34.5 kV)
  - Distribution: 15 to 1 (< 34.5 & > 1 kV)
  - Low Voltage: 8 to 1 (< 1 kV)

- Average transmission customer site is 8 times more likely to experience a voltage sag than an outage or momentary interruption

RESILIENCE – EXTENDING THE OPERATING ENVELOPE

“Extending the operating envelope” of equipment means reducing the area of equipment malfunctions by enabling the equipment to ride through deeper and longer voltage sags

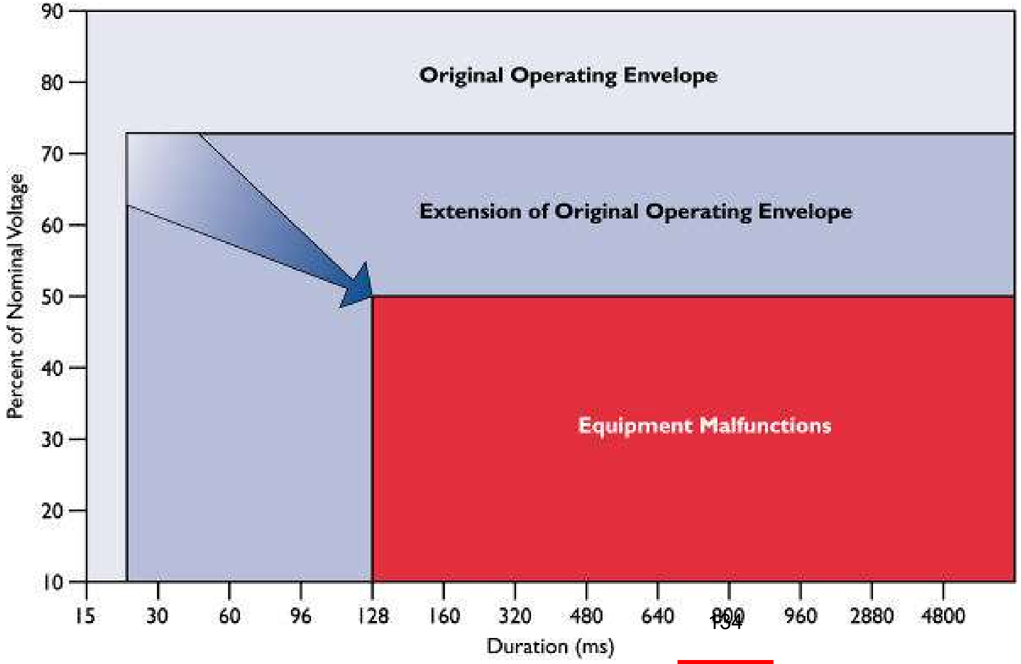


Table 10 —Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
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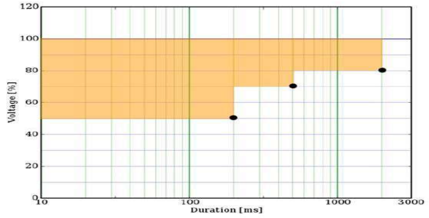

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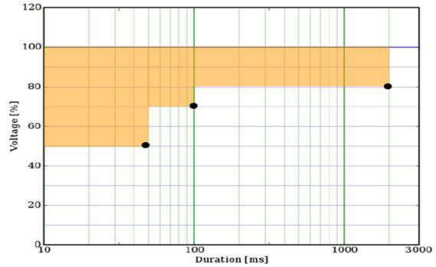
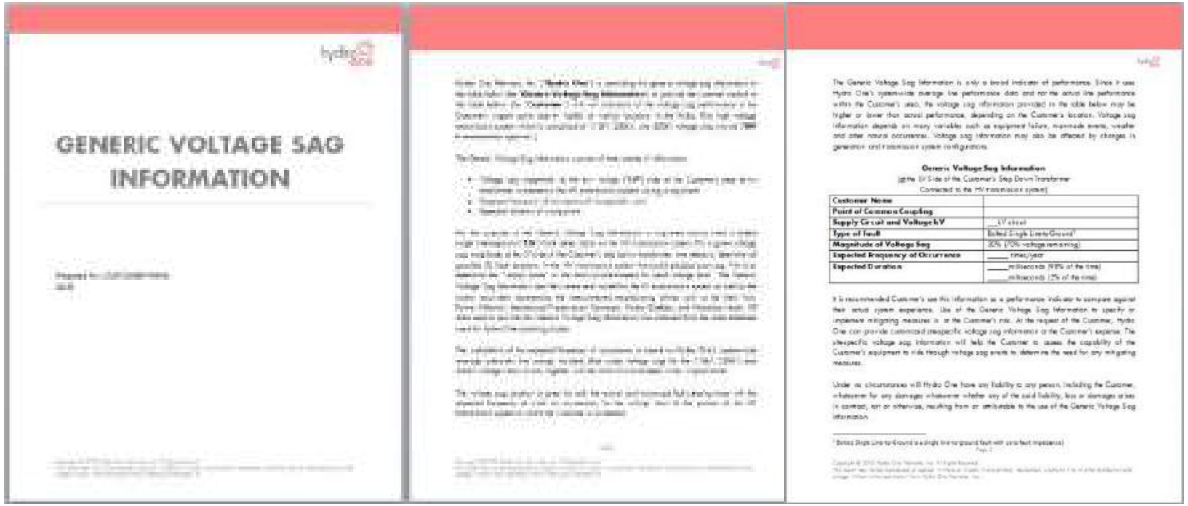


Figure 23—Recommended Type III test levels

WHAT IS HYDRO ONE DOING ABOUT PQ?

VOLTAGE SAG REPORTS –
TRANSMISSION-CONNECTED CUSTOMERS



Customer Name	
Point of Common Coupling	
Supply Circuit and Voltage kV	___kV circuit
Type of Fault	Bolted Single Line-to-Ground
Magnitude of Voltage Sag	30% (70% voltage remaining)
Expected Frequency of Occurrence	_______ times/year
Expected Duration	136 _______milliseconds (98% of the time) _______milliseconds (2% of the time)

hydro one

IMPROVING PQ VISIBILITY

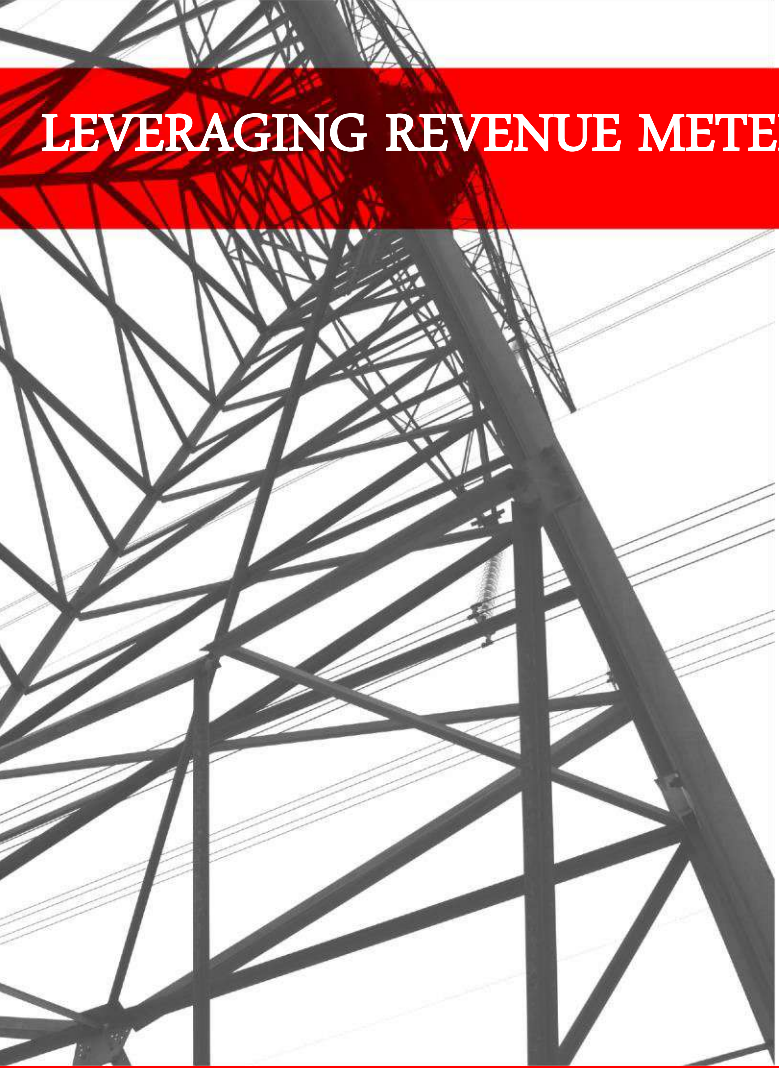
- Increasing visibility of PQ measurements both in Tx and Dx
    - PQ meters installed to date = 345 Tx,
      331 Dx (DG)
    - Average installed per year to Dx = 50 (DG)
    - Planned installations for Tx = 49 (by end of 2020)

- Program to leverage/integrate Customer revenue meters into PQWeb
  (12 Tx end users to date)

LEVERAGING REVENUE METERS

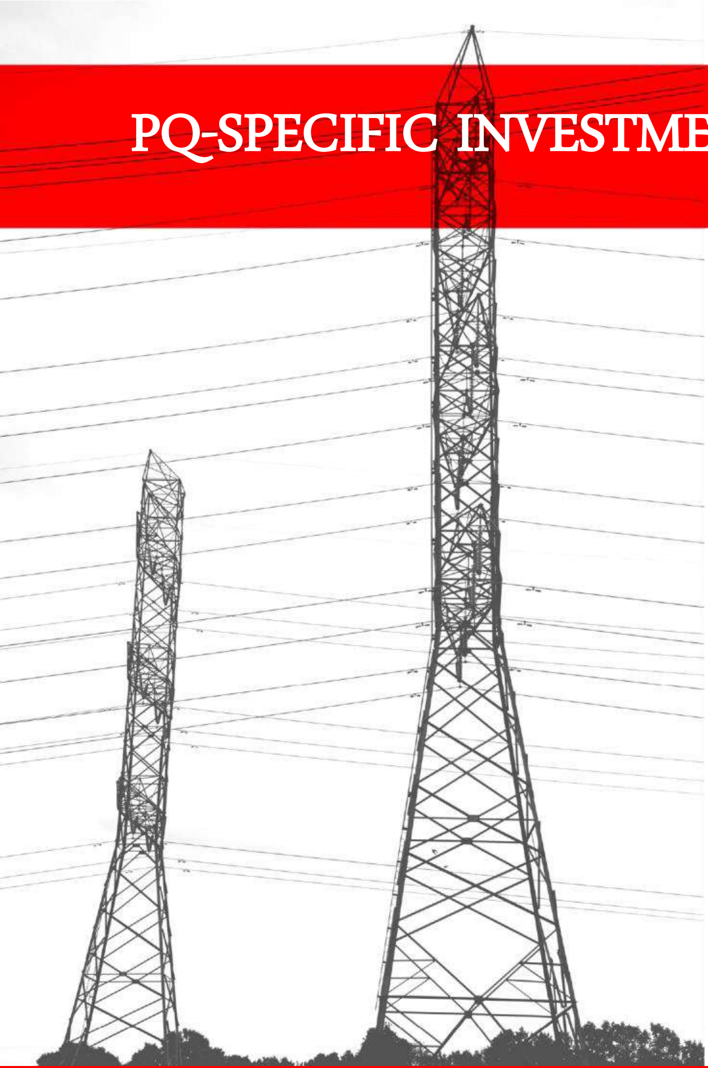
- Program to be reviewed December 2020
- Installation and telecom costs are paid by Hydro One
- Measurements at the metering point are more accurate and do not require reverse engineering from station measurements, if available
- Speeds up PQ investigations and resolution. Allows evaluation of long term PQ performance

LEVERAGING REVENUE METERS (CONT'D)

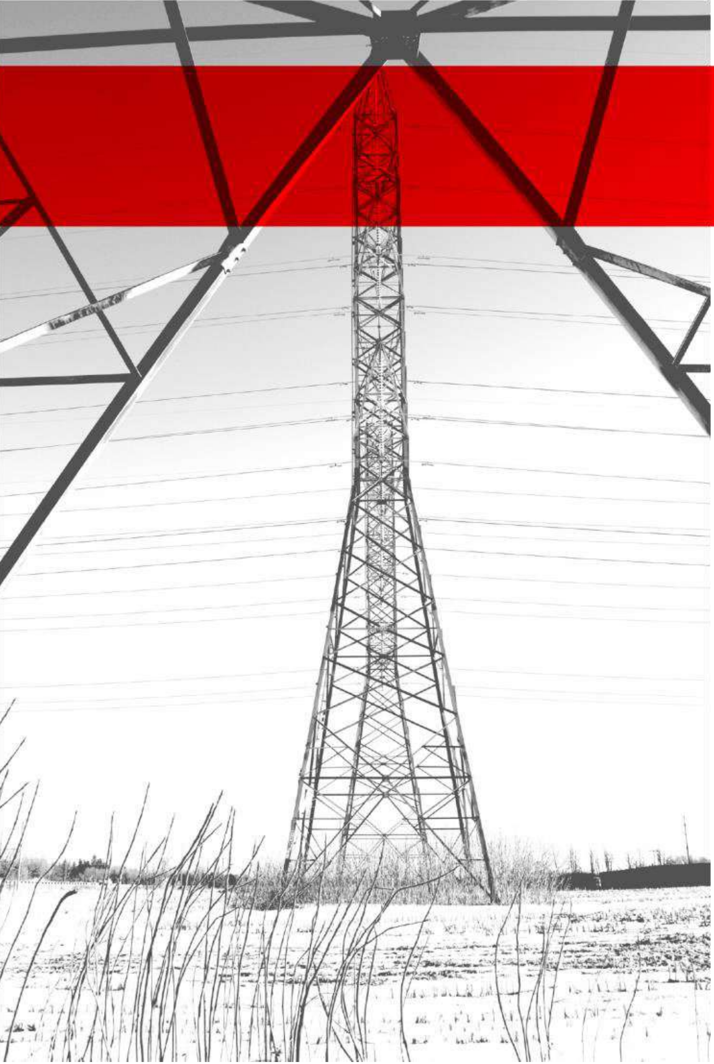


- Customers can review their own PQ data (free software available)
- Customers can potentially take control of their own resilience

PQ-SPECIFIC INVESTMENTS



- Dedicated PQ investment drivers
- Investigate and invest in practical and financially prudent non-reactive measures that improve PQ
- Support of 3rd party Power Quality Audits



WHAT DOES A PQ AUDIT LOOK LIKE?

1. Utility Side Analysis

2. Plant System Analysis and Recommendations

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UTILITY-SIDE ANALYSIS:
SARFI DATA

$$SARFI_x = \frac{\sum N_i}{N_T}$$

- System Average RMS (Variation) Frequency Index
- Typically normalized to per site/per year data
- The index provides a count of all events with magnitudes and durations outside or below the index threshold
  - SARFI-70 provides a normalized count of all voltage sags with a retained voltage less than 70% of nominal (regardless of duration) in a time period
  - SARFI-10 represents a normalized count of the number of interruptions experienced at the site

Table 10—Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
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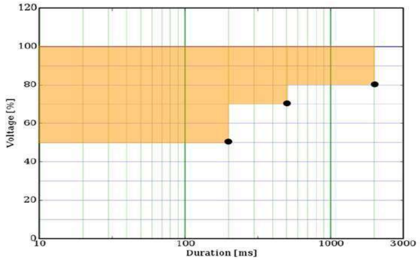

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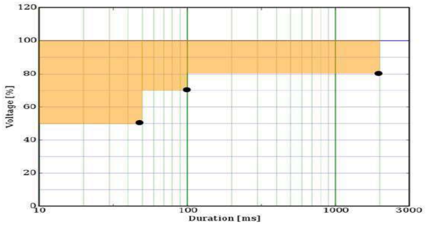

Figure 23—Recommended Type III test levels

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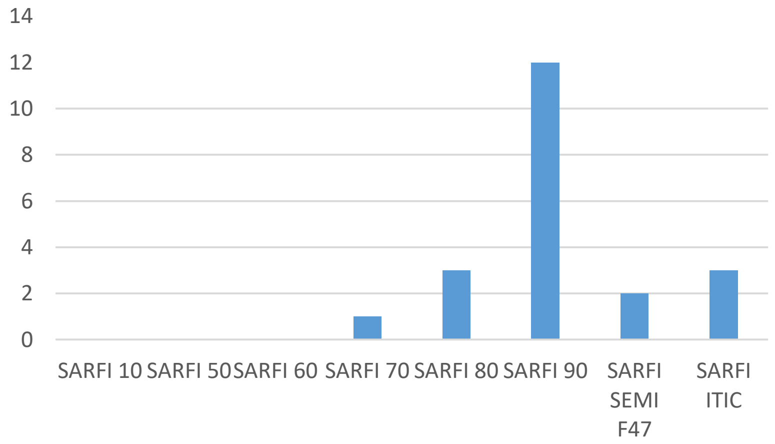
SARFI DATA

Import Name	(5/31/2015 - 12/8/2015)	
Event Count	12 total events	
Monitor Years	0.52 years	
Average Sag Magnitude (%)	82.30%	
Average Sag Duration (sec)	0.362s	
Median Sag Magnitude (%)	84.50%	
Median Sag Duration (sec)	0.125s	
	Normalized to 1 Year	Raw Count
SARFI 10	0.0	0
SARFI 50	0.0	0
SARFI 60	0.0	0
SARFI 70	1.9	1
SARFI 80	5.7	3
SARFI 90	22.9	12
SARFI SEMI F47	3.8	2
SARFI ITIC	5.7	3

- This dataset represents only 0.52 years of information
- Takeaways:
    - Data Set Incomplete
    - Average Sag Magnitude 82.3%
    - Average Sag Duration is 0.362 sec
    - Median Sag Magnitude is 84.5%
    - Median Duration is 0.125 sec



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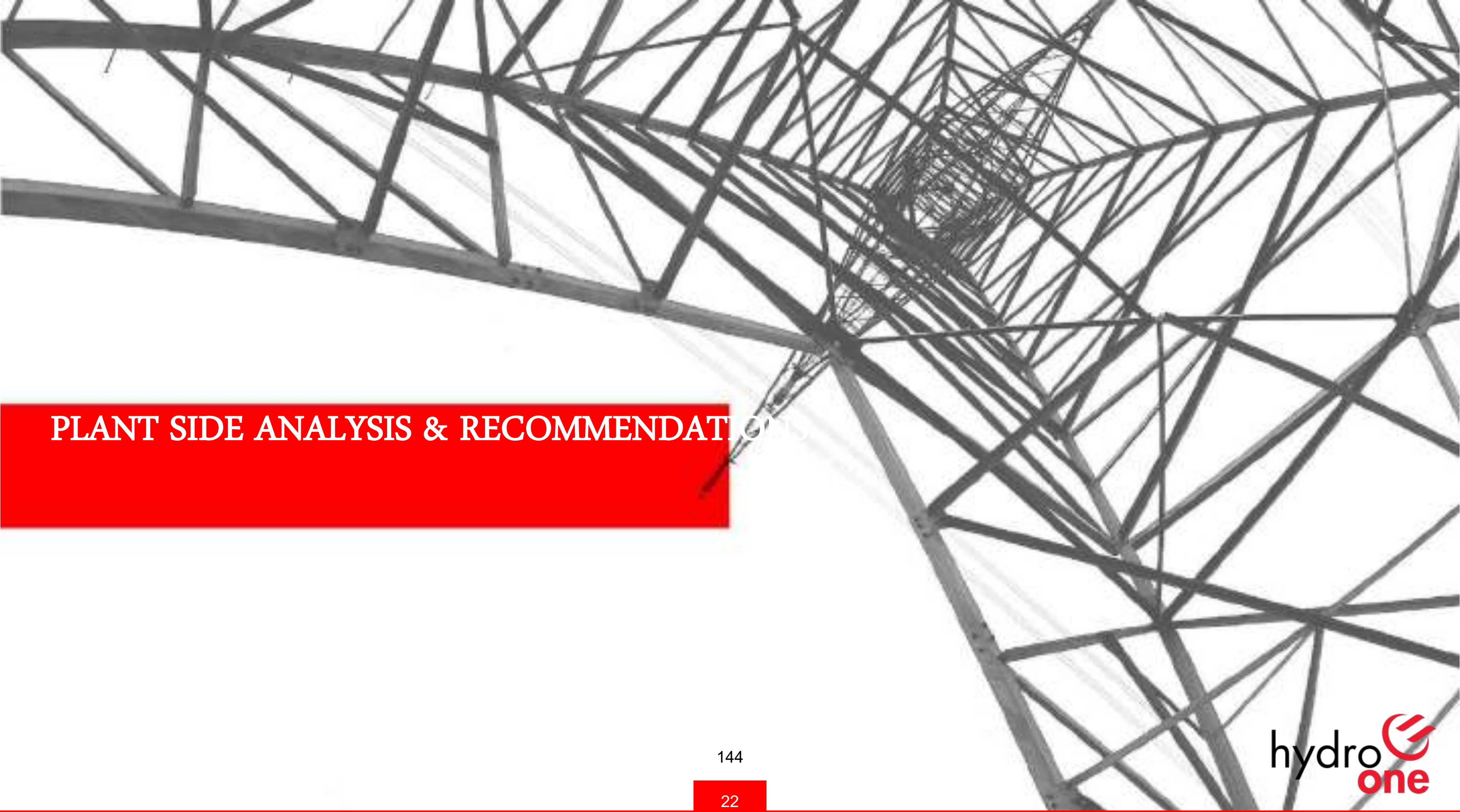

PLANT SIDE ANALYSIS & RECOMMENDATIONS

RESILIENCE – EXTEND THE OPERATING ENVELOPE

- “Extending the operating envelope” of equipment means that we have to reduce the area of equipment malfunctions by enabling the equipment to ride through deeper and longer voltage sags.

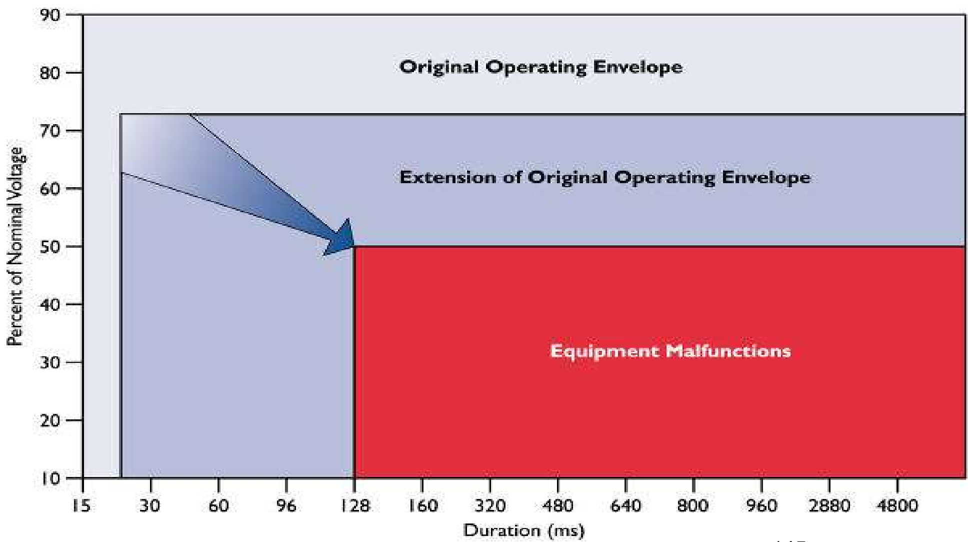

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Table 10—Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.2	10 cycles	12 cycles
2	70%	0.5	25 cycles	30 cycles
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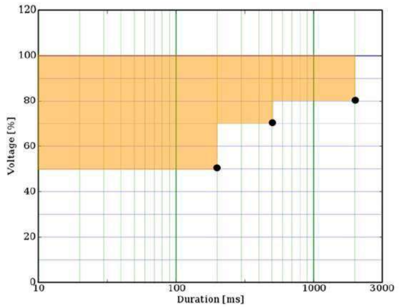

Figure 22—Recommended Type I and Type II test levels

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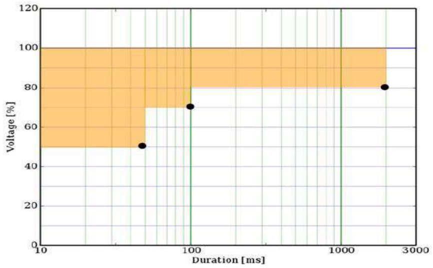
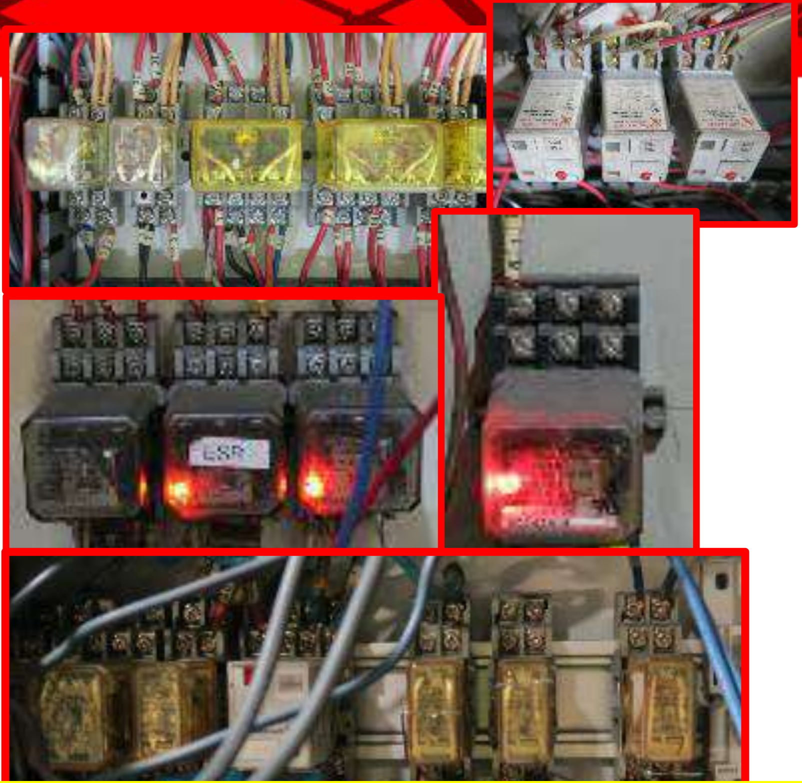


Figure 23—Recommended Type III test levels

KEY FINDINGS FROM [CUSTOMER] ON-SITE AUDIT

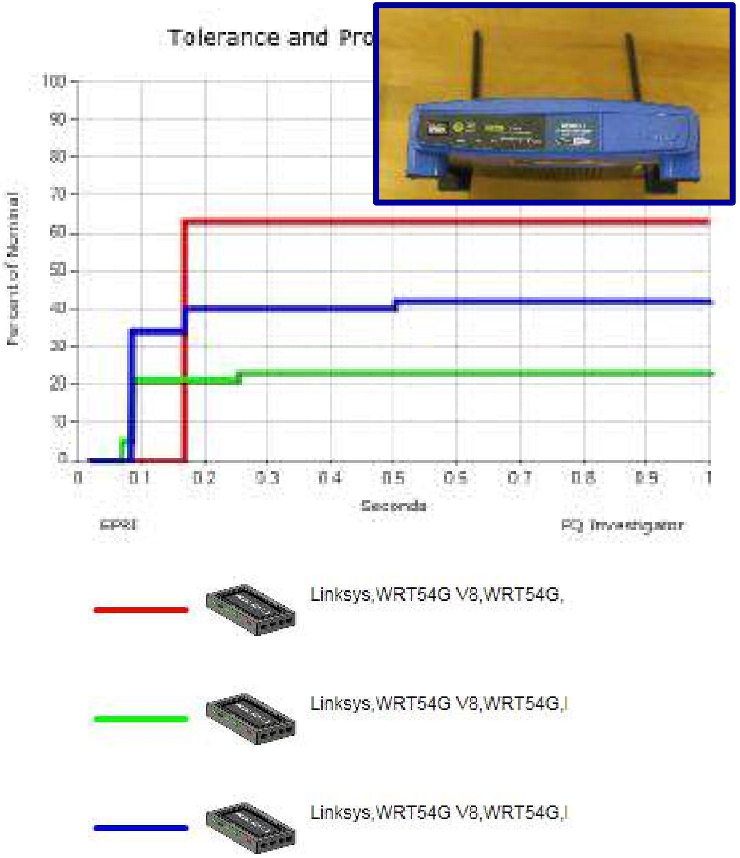
- Most of the process equipment was originally manufactured in the 1990's
  - Equipment has been moved to [customer] from different facilities around the world
  - Equipment has been upgraded on more than one occasion during its 20+ years of service
  - Equipment is largely dependent upon a coordinated drive system
  - The safety and run permissives of the controls were fed through the contacts of AC Ice Cube relays which are sensitive to voltage sags
  - The voltage sag ride through of these clear plastic relays is typically 1cycle 72%



Major Finding: Any voltage sag lower than 72% will cause the relay contacts to open and remove run permissive(s), enable signals, and potentially trigger a false Emergency Power Off (EPO).

KEY FINDINGS FROM ON-SITE AUDIT (CONT'D)

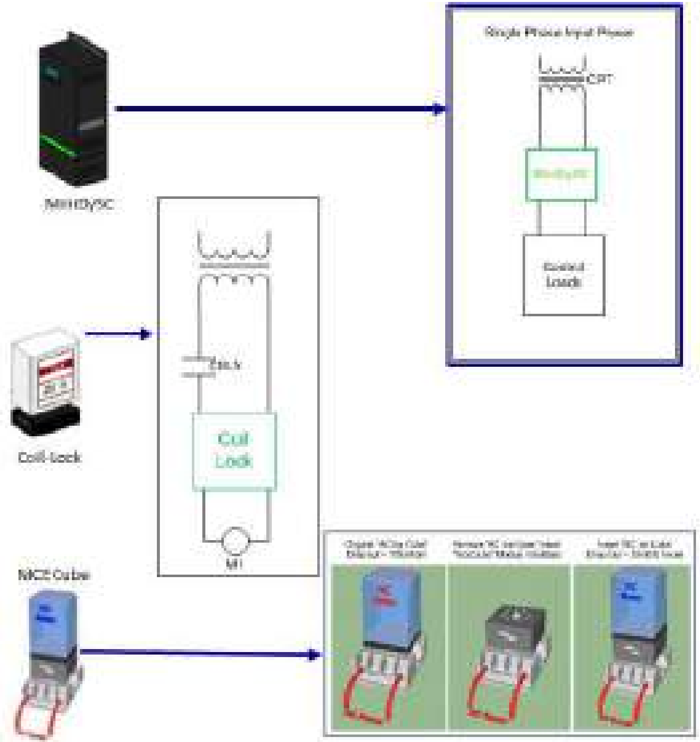
- The equipment has been upgraded on several occasions
- The newest ASDs in the facility communicate through local area network hubs LAN
- These hubs were powered through the service outlets in the cabinets
- May times these service outlets are not powered from the same source as the controls
- Some of these hubs are sourced through outlet style plug in power supplies
- EPRI tested a router using three different power supplies
    - The results were drastically different.
    - The power supply with the highest current rating actually produced the worst voltage sag ride through performance.



TYPES OF VOLTAGE SAG

PQ SOLUTIONS

- MiniDySC
  - Static Series Compensator with Capacitor Storage
  - Control Circuit Mitigation
  - 50ms of voltage interruption (more time at reduced load)
- 5 seconds of voltage sag protection to 50% nominal
  - Coil Lock
  - Relay Coil Solution
  - Size based upon coil resistance
  - 3 seconds of voltage sag protection to 25% nominal
- Nice Cube
  - 8 pin octal Ice Cube Relay Solution
  - Direct replacement for 120Vac and 24Vac octal relays
  - 3 seconds of voltage sag protection to 30% nominal



COMPARISON OF VOLTAGE SAG VS. INTERRUPTION SOLUTIONS

Voltage Sag Solutions

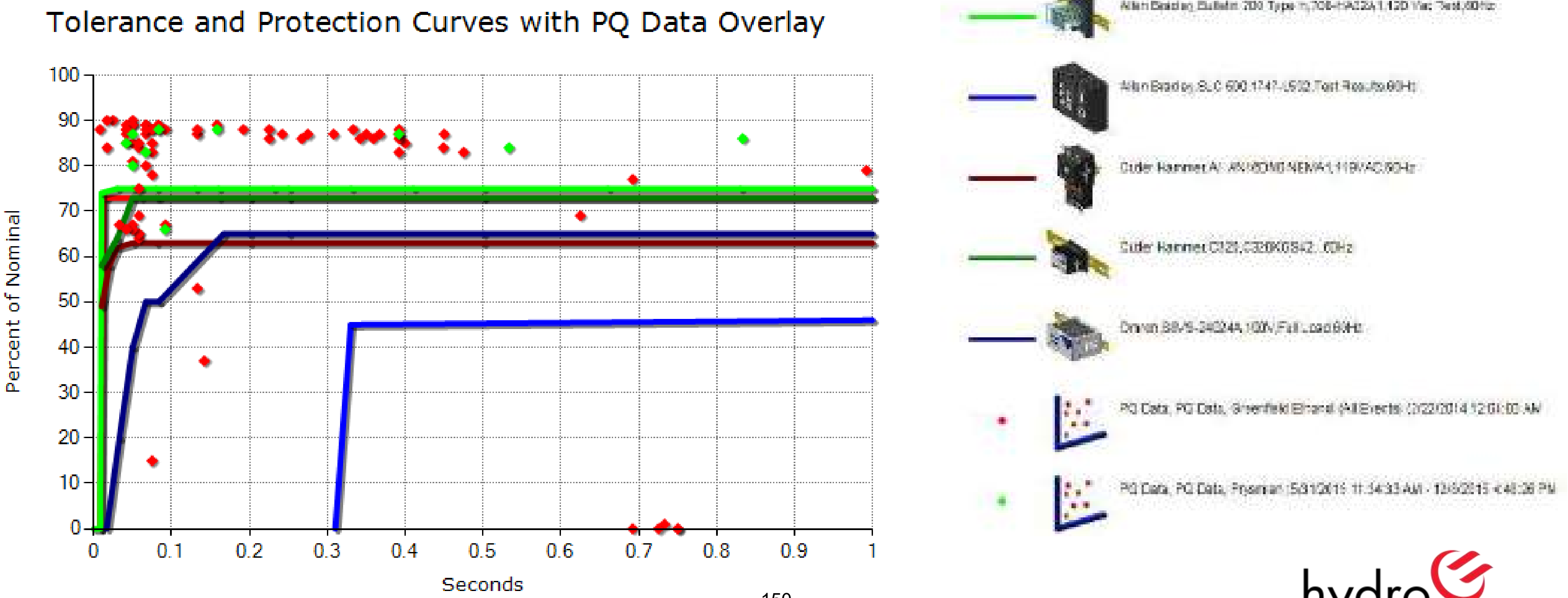
- Pros
  - Lower Cost
  - Less Maintenance
- Cons
  - Less ride through time
  - Protects for voltage sags only
  - Some solutions will protect for a couple cycles of voltage interruption

Interruption Solutions

- Pros
  - Longer ride through time
  - Protection to 0 volts
- Cons
  - Higher cost
  - Ultra Capacitor UPS requires fan maintenance

PQ DATA VS. EQUIPMENT SUSCEPTIBILITY

The majority of the control components that were observed during the audit are included in the graphic below



EPRI PQ Investigator

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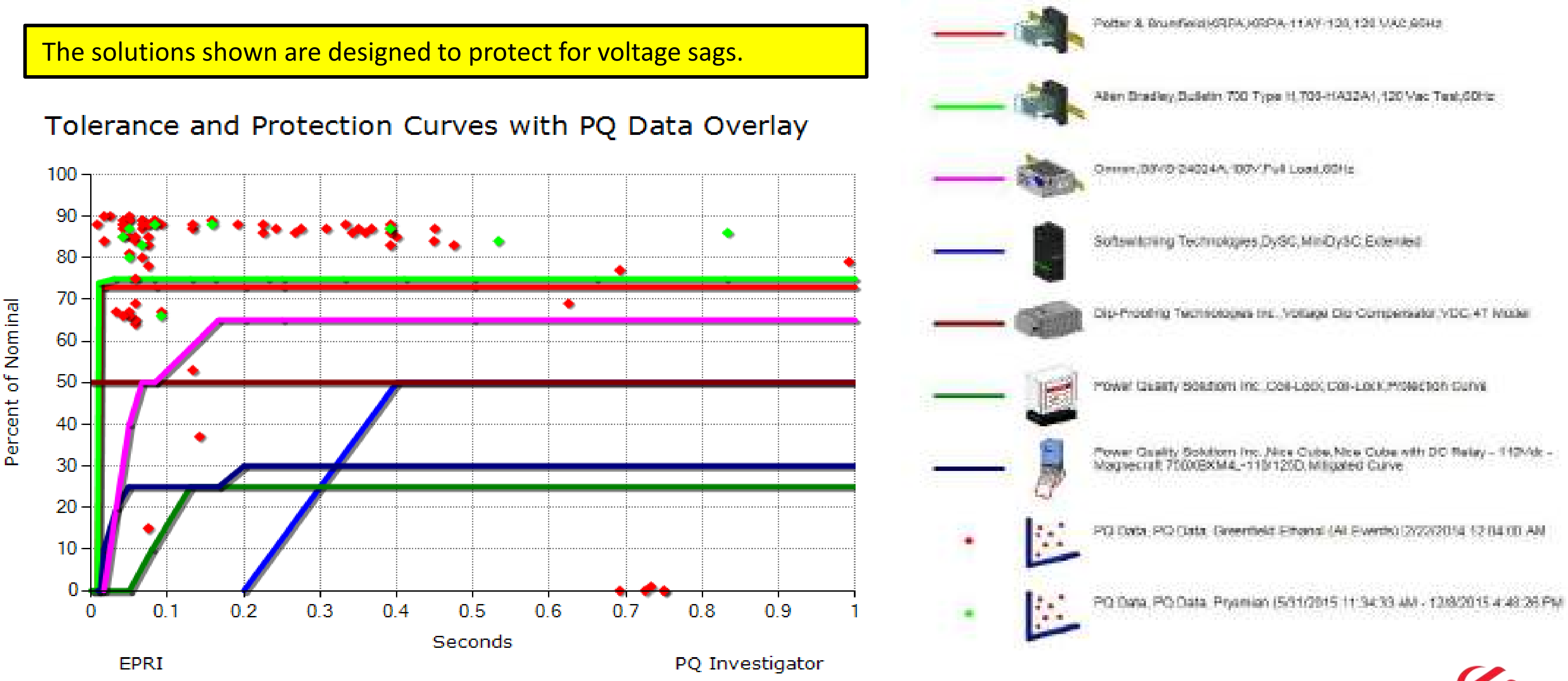
PQ DATA WITH EQUIPMENT SUSCEPTIBILITY AND MITIGATOR

The solutions shown are designed to protect for voltage sags.



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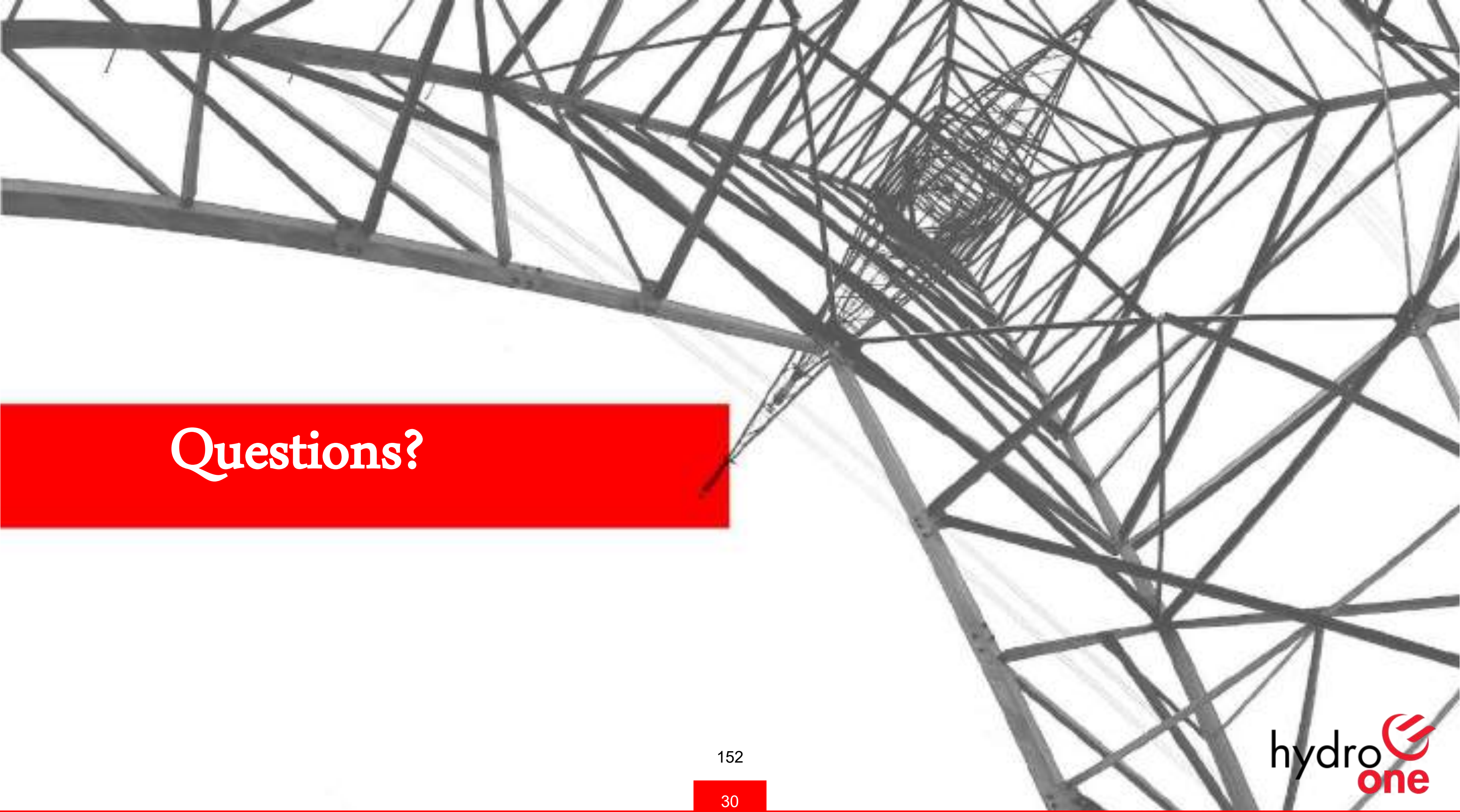
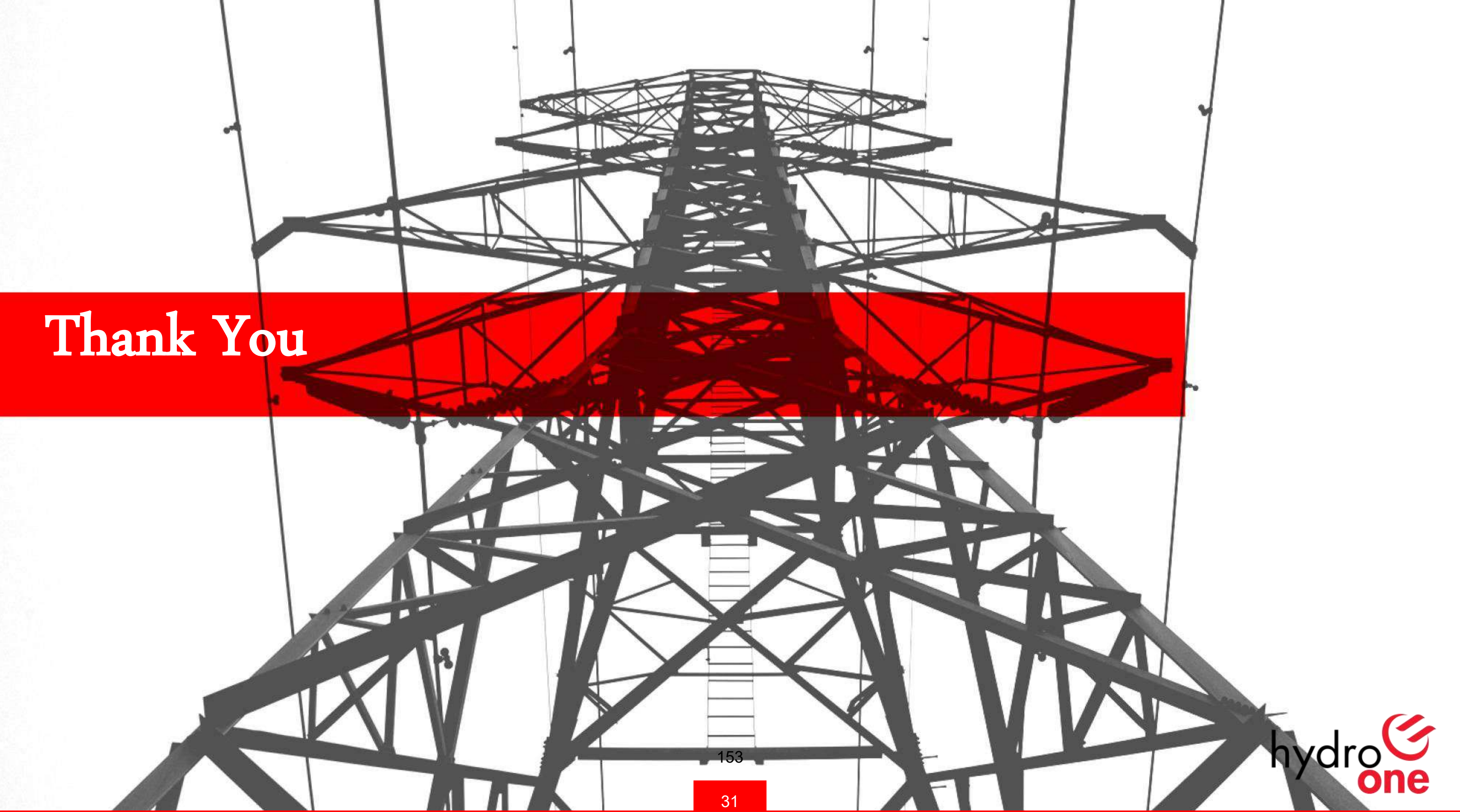


Questions?



Thank You

Table 10 —Recommended test points for Type I and Type II voltage sags

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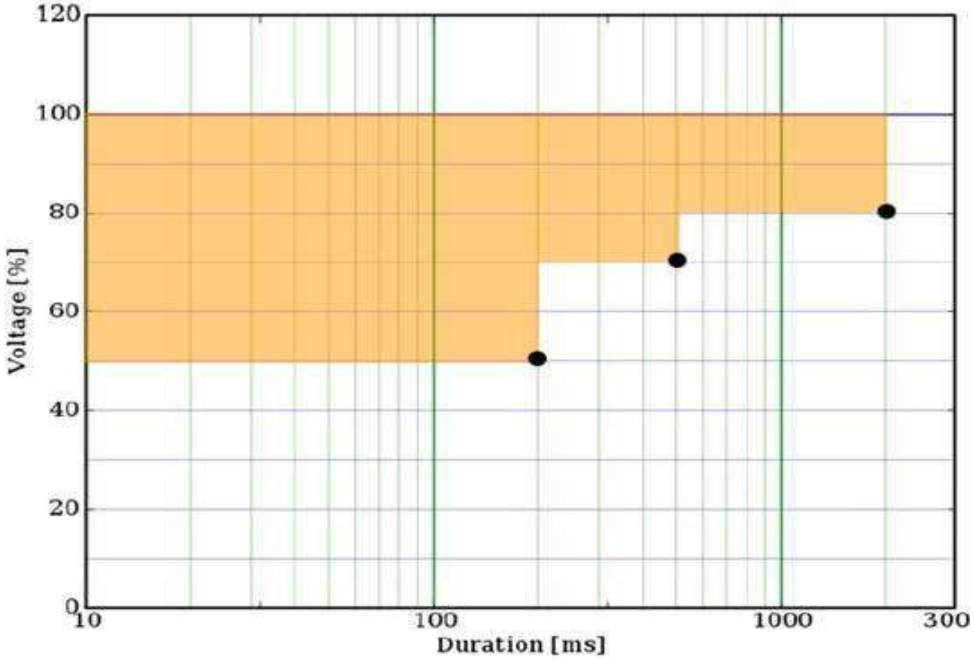

Figure 22 —Recommended Type I and Type II test levels

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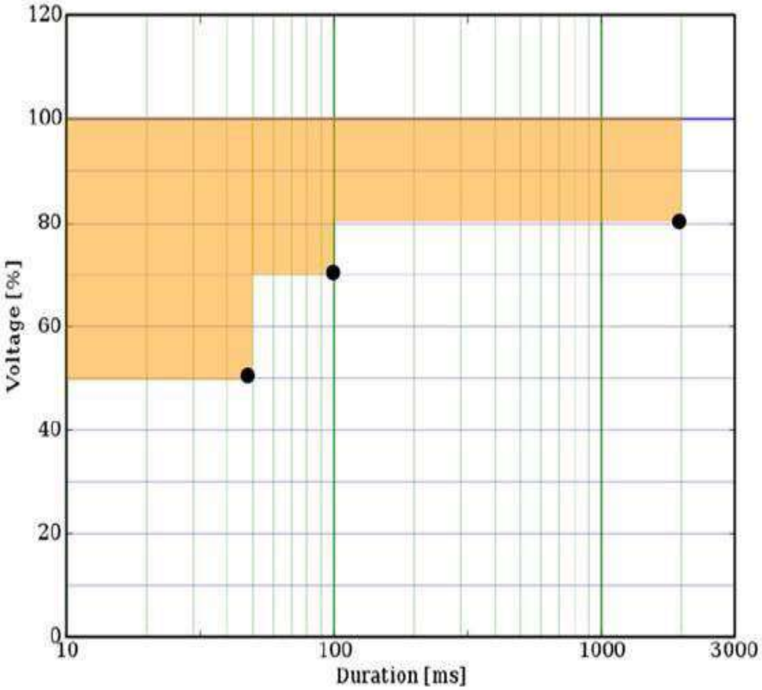
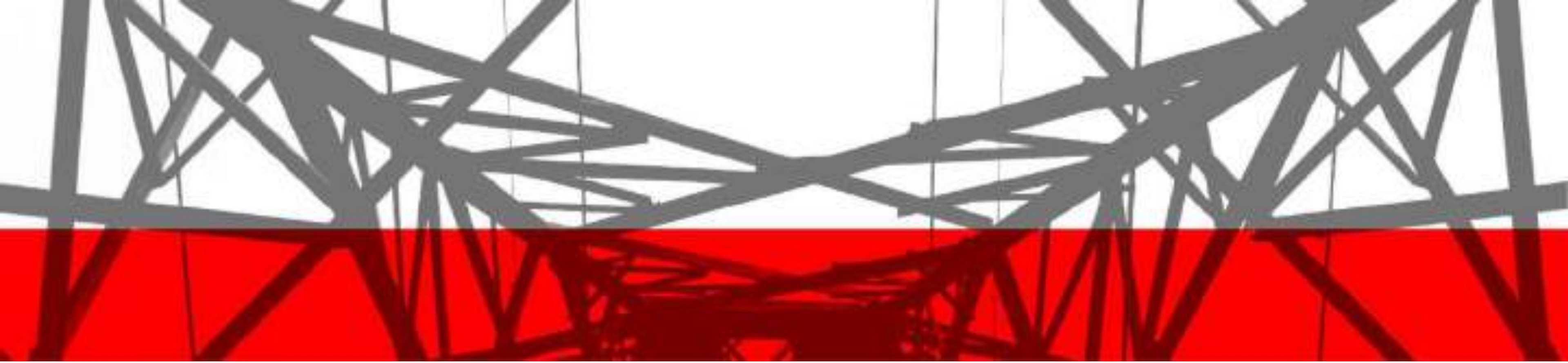


Figure 23 —Recommended Type III test levels

LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



POWER QUALITY

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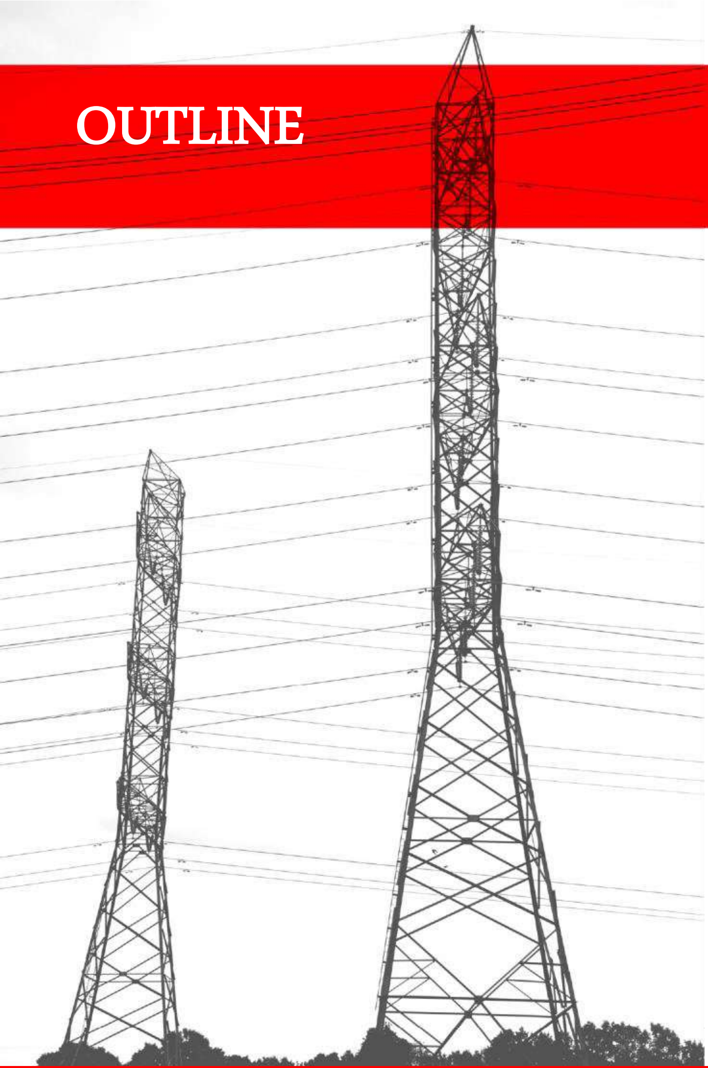
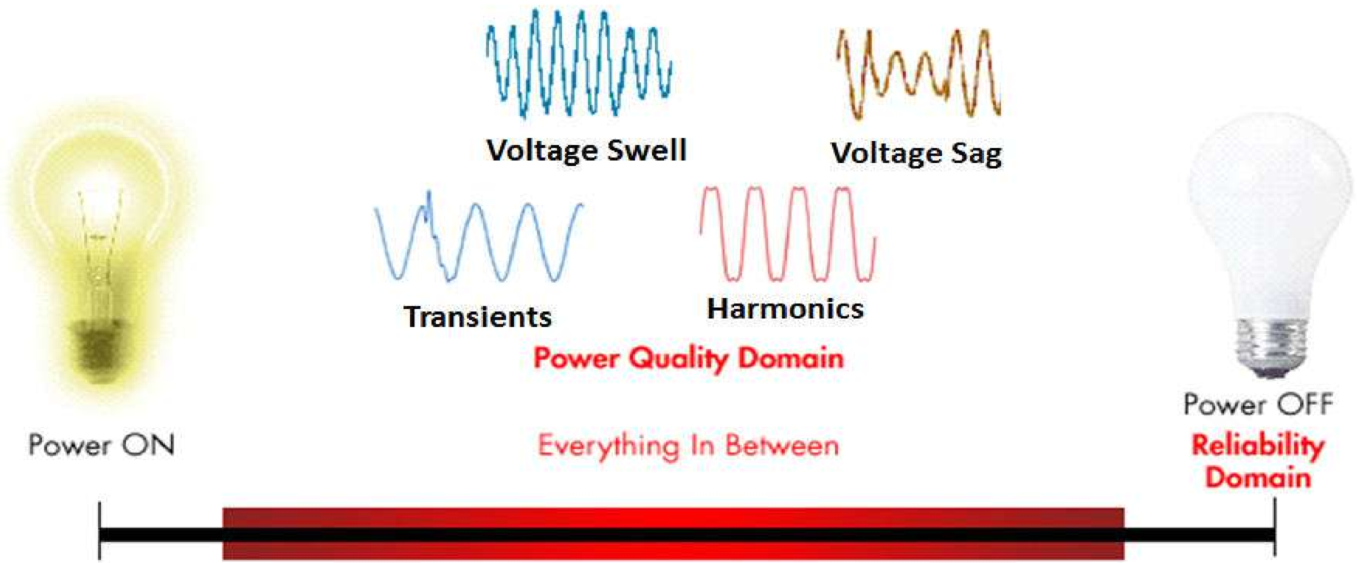
hydro one



OUTLINE

- Power Quality vs. Reliability
  - Resiliency vs. Delivery Point Interruptions
  - Types of Power Quality issues
  - Voltage Sag
- Initiatives
  - Revenue meter leverage
  - PQ audits

POWER QUALITY VS. RELIABILITY



Traditional Reliability Measures

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

POWER QUALITY

- Power Quality (PQ) is a term used to describe harmonics, flicker, voltage imbalance, transients etc., excluding Delivery Point interruptions

- Formal PQ Definition: “Any problem that is manifested in voltage, current or frequency deviations [or tripping] that result in failure or misoperation of utility or end user equipment”

- PQ events can have high cost impact for industrial customers and generators depending on the individual plant and internal processes

- Within the Hydro One system, the most common PQ issues that affect generators and loads are:
    - Transient overvoltages caused by sub-transmission capacitor bank switching.

POWER QUALITY (CONT'D)

- Transient overvoltages caused by HV capacitor bank switching are not normally a problem because of the use of IPO (Independent Pole Operated) breakers to switch capacitors in and out of service

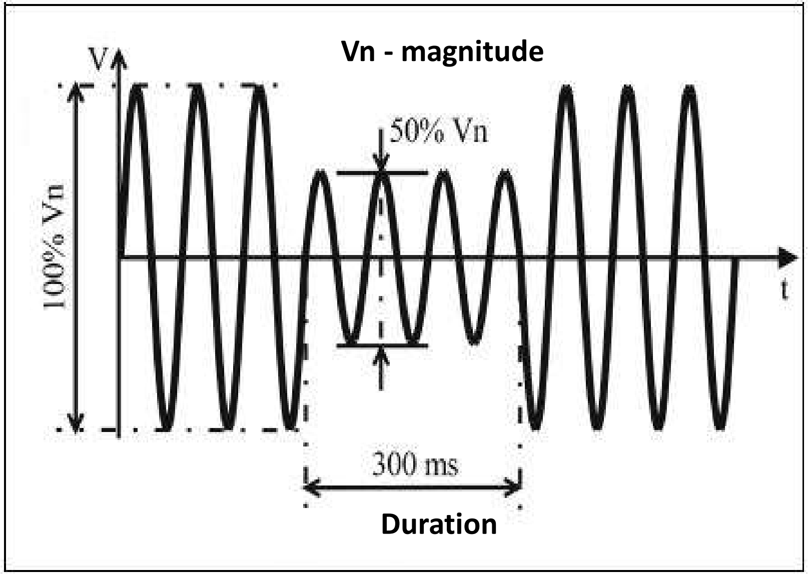
- For renewable generation Hydro One's concern is the potential for system resonance, especially as the network configuration changes over time
  - For DGs PQ monitors are installed routinely
  - Requirement for of monitors for Tx-connected renewable generation is now in place.

- Harmonics produced by inverter-based generation is usually within IEEE Std 519 limits

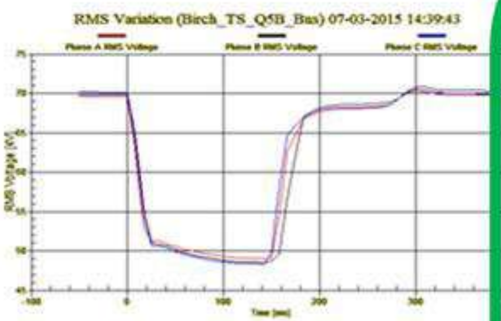
- High voltage harmonics may exist when system configuration with parallel resonance frequencies for the electrical network are close to those produced by inverter-based generation.
  - May cause excessive heating of power equipment such as transformers
  - May cause misoperation of WF and HON P&C.

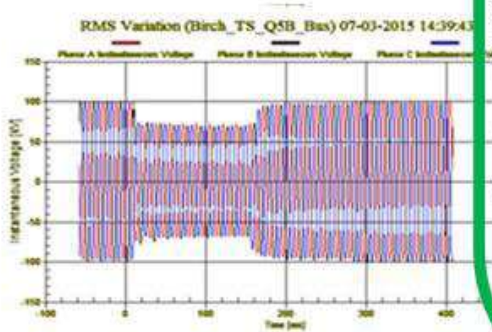
POWER QUALITY (CONT'D)

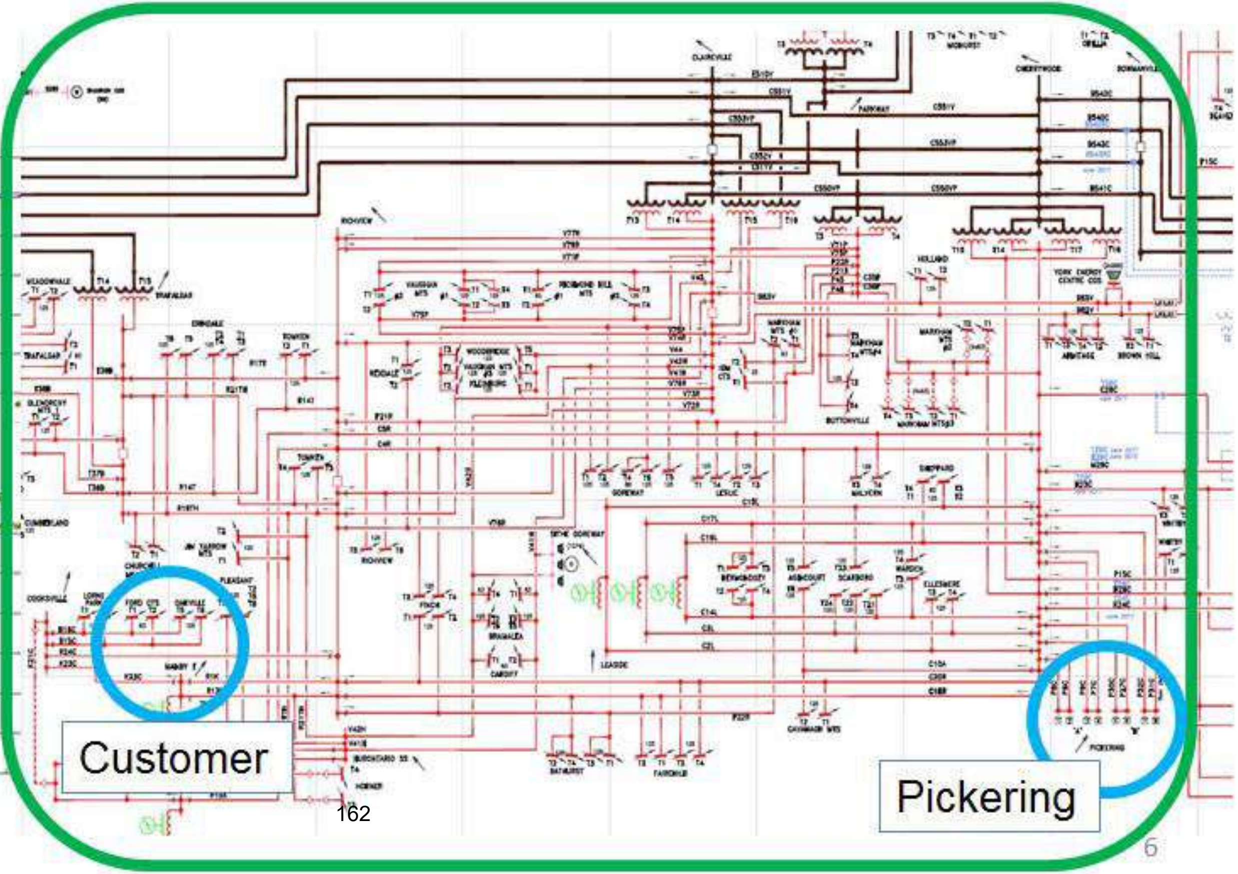
- Voltage sag is probably the most common power quality issue affecting Transmission and Distribution customers
- Momentary % drop in voltage magnitude due to a fault in the system
- System dependent: "zone of influence"
- If customer's equipment cannot "ride through" the momentary drop in the voltage, equipment would generally disconnect automatically
- Unlike delivery point interruptions (which are a measure of system reliability), the effects of voltage sag events are a combination of:
  - Severity of the sag
  - Duration of the sag
  - Resilience of the load



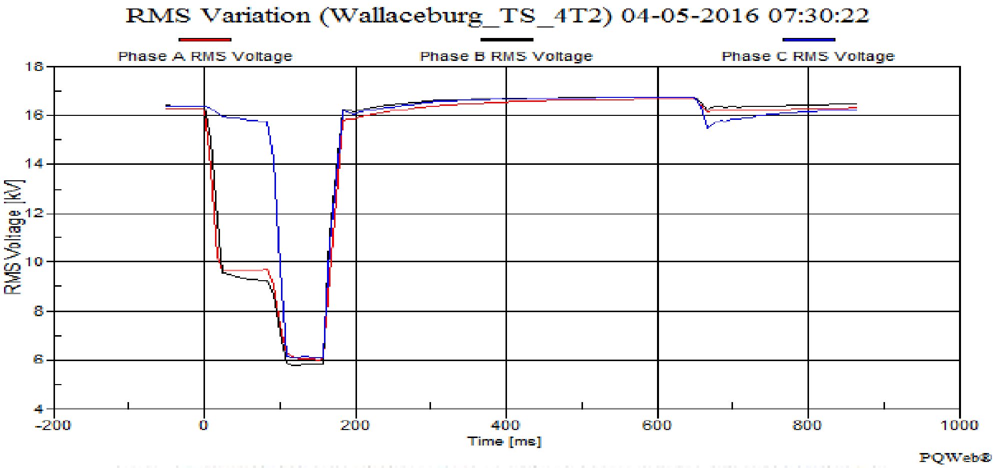
A FAULT WITHIN THE ZONE OF INFLUENCE CAN CAUSE A VOLTAGE SAG EVENT AT A CUSTOMER'S SITE

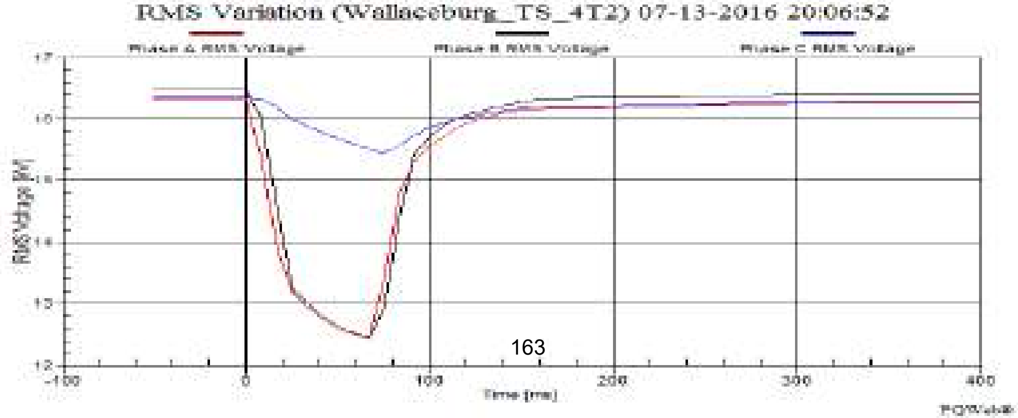






TYPICAL EVENTS CAPTURED





VOLTAGE SAG

- Standard IEEE1668 provides some guidance regarding load resilience in the form of recommended practices (not requirements / standards / compliance requirements)
- It is intended for customers to specify equipment procurement with OEMs. It carefully avoids suggesting any type of required utility / customer interface compatibility or performance
- All references to voltage sag pertain to the load side

Table 10—Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.2	10 cycles	12 cycles
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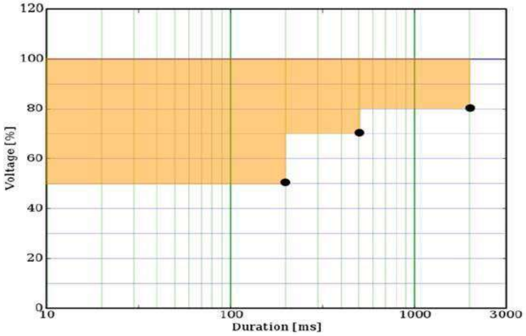

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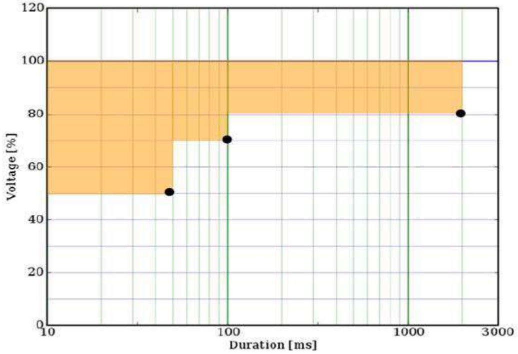


Figure 23—Recommended Type III test levels

VOLTAGE SAG (CONT'D)

- There are no metrics for the frequency of sag events for a number of reasons:
  - Sag events are logged in PQ meters but there is no way to know if the events are impactful to a customer
  - Impact of a sag event depends on the load's ride-through capability. There are no North American standards that mandate a specific level of resiliency.
  - Standard IEEE1668 is a good guidance reference point

- With station PQ meters, Hydro One has no direct visibility on whether a load is affected by voltage sag issues and relies on customer-provided information to assess whether ride-through was successful or not

PQ VS. DELIVERY POINT PERFORMANCE

- Hydro One's experience is consistent with the findings of EPRI's distributive power quality study (DPQ III): voltage sags are the most common power quality event

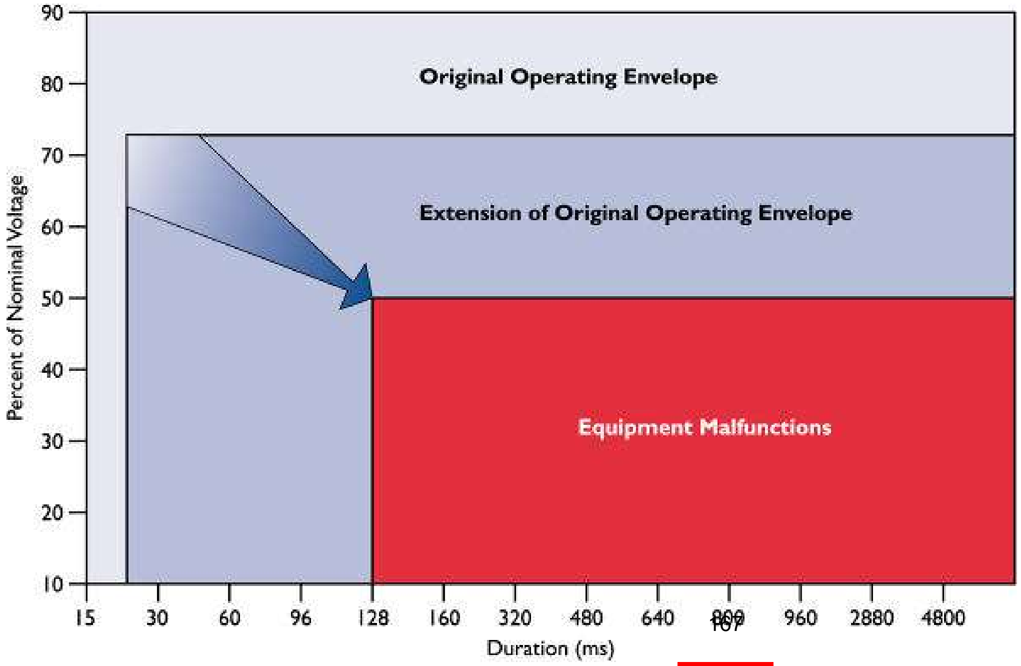
- DPQ III showed that a facility is 8 -20 times more likely to receive a voltage sag than an interruption

- The ratio of sags to interruptions found in the DPQ III study based on circuit type:
  - Transmission: 8 to 1 (> 100 kV)
  - Sub-Transmission: 20 to 1 (100 kV & > 34.5 kV)
  - Distribution: 15 to 1 (< 34.5 & > 1 kV)
  - Low Voltage: 8 to 1 (< 1 kV)

- Average distribution fed customer site is 15 times more likely to experience a voltage sag than an outage or momentary interruption

RESILIENCE – EXTENDING THE OPERATING ENVELOPE

- “Extending the operating envelope” of equipment means reducing the area of equipment malfunctions by enabling the equipment to ride through deeper and longer voltage sags



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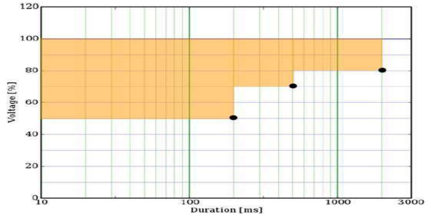

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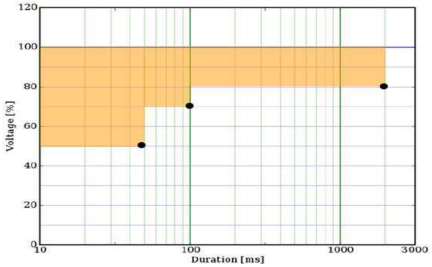
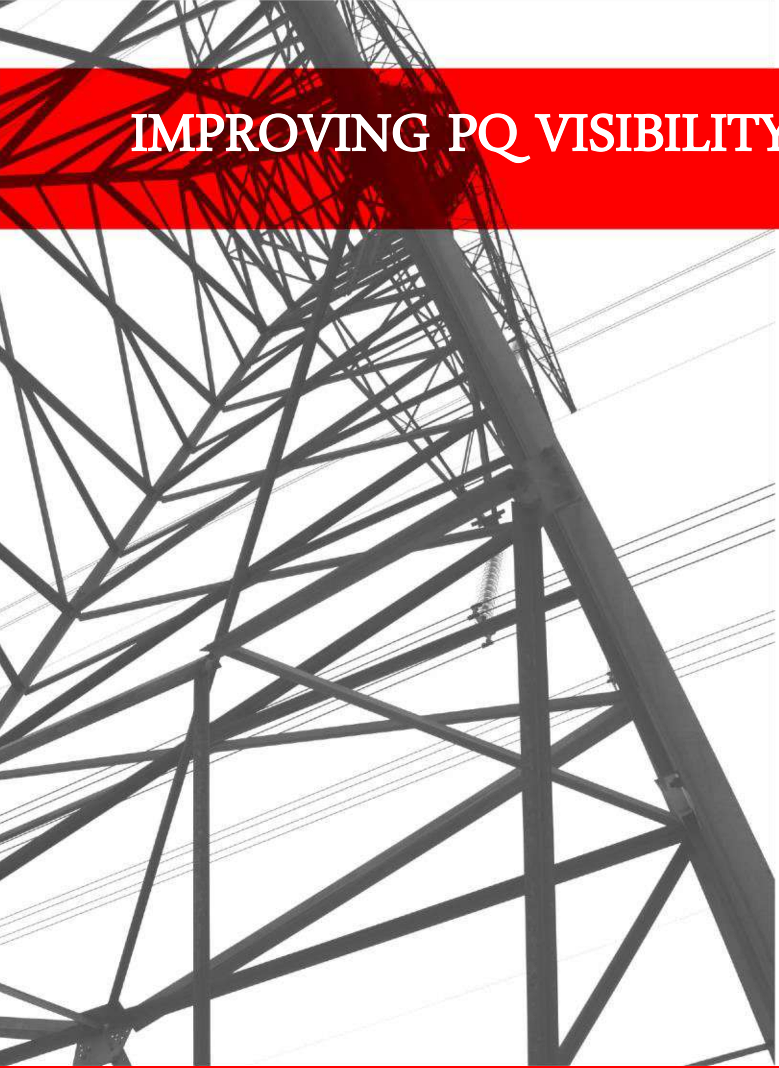


Figure 23—Recommended Type III test levels

WHAT IS HYDRO ONE DOING ABOUT PQ?

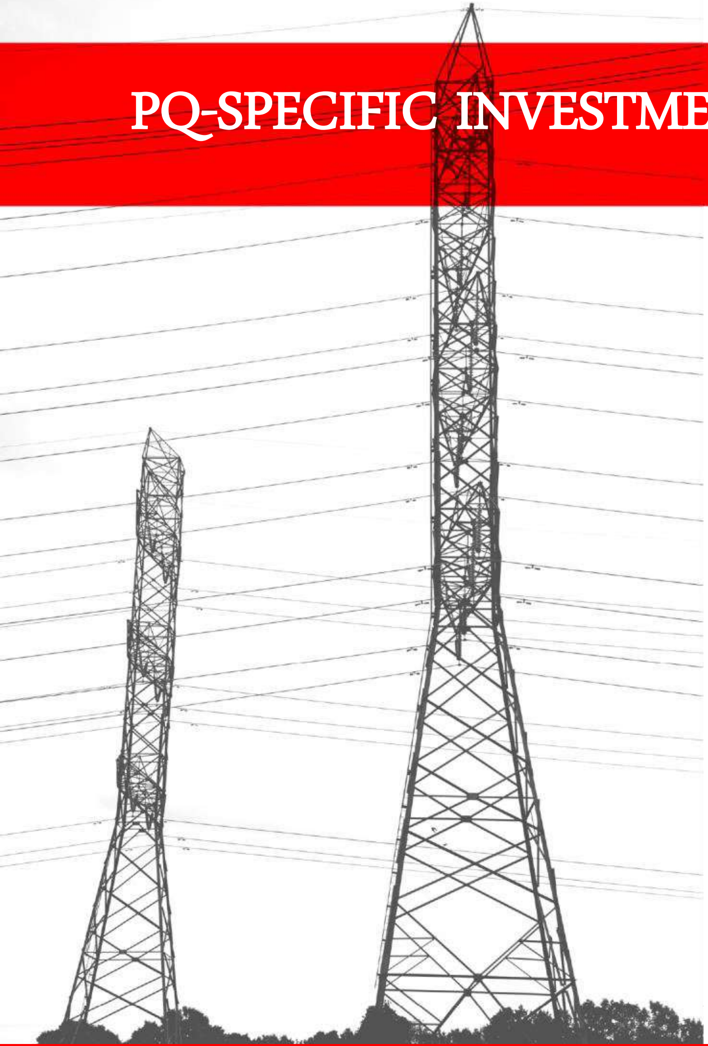


IMPROVING PQ VISIBILITY

- Increasing visibility of PQ measurements both in Tx and Dx
  - PQ meters installed to date = 345 Tx, 331 Dx (DG)
  - Average installed per year to Dx = 50 (DG)
  - Planned installations for Tx = 49 (by end of 2020)

- In the works: Program to leverage / integrate Customer revenue meters into PQWeb
  (12 Tx end users to date)

PQ-SPECIFIC INVESTMENTS



- Dedicated PQ investment drivers
- Investigate and invest in practical and financially prudent non-reactive measures that improve PQ
  - For example, a pilot to evaluate the performance of 72kV capacitor bank switchers with pre-insertion resistors to reduce switching transients. First installations at Napanee & Muskoka.
- Support of 3rd party Power Quality Audits
  - Not as common for generators as for loads.

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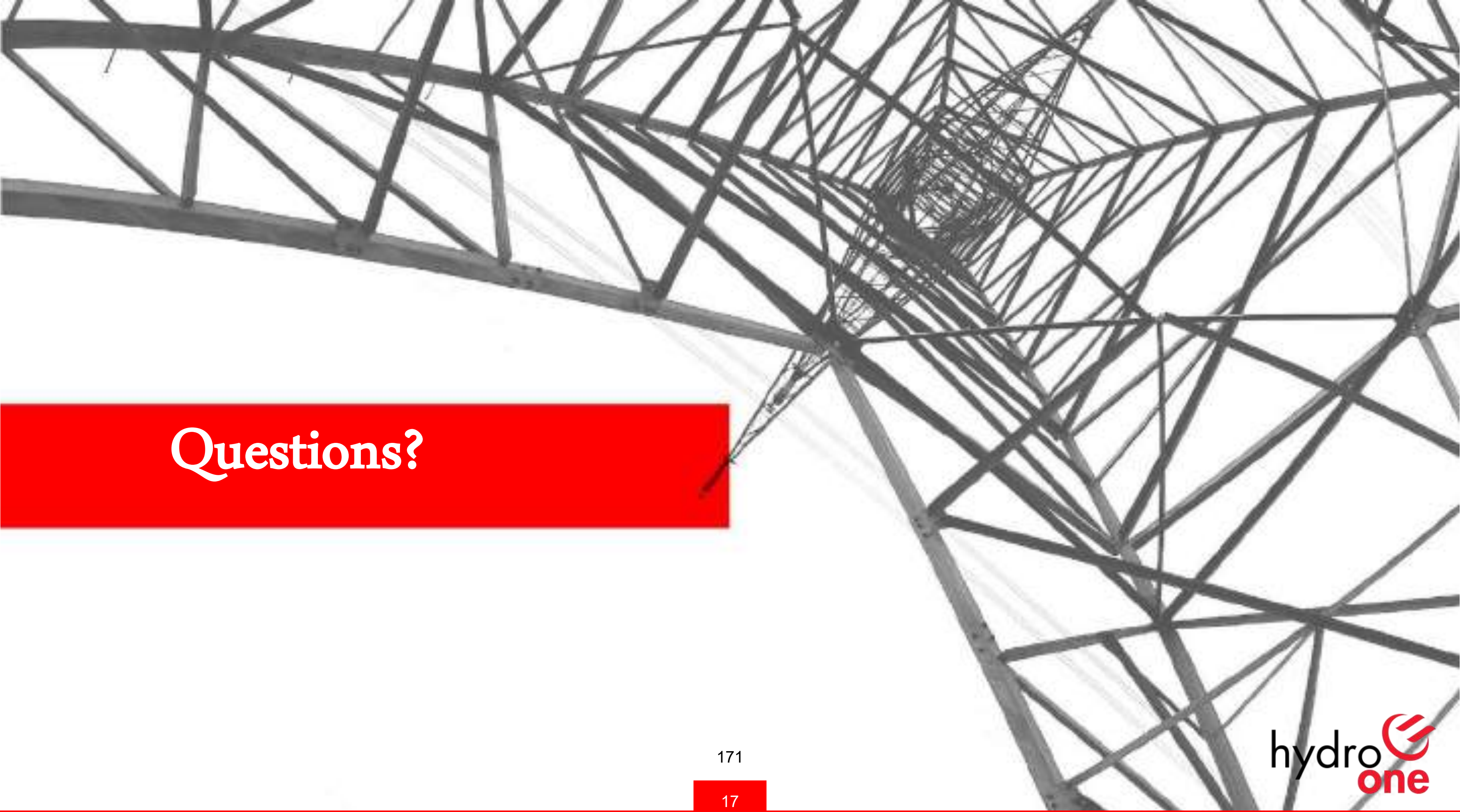
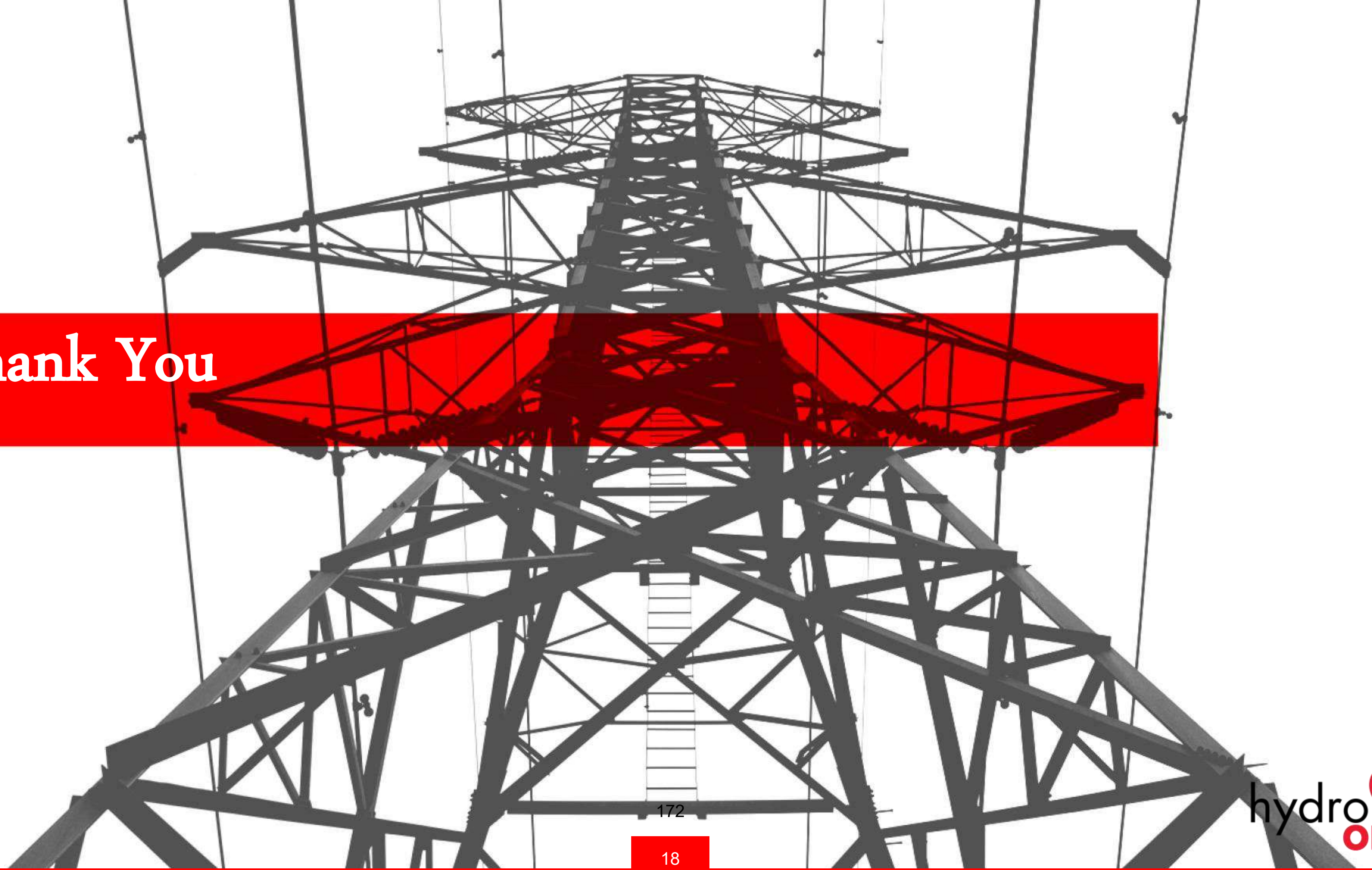


Questions?

Thank You



STANDARD IEEE1668

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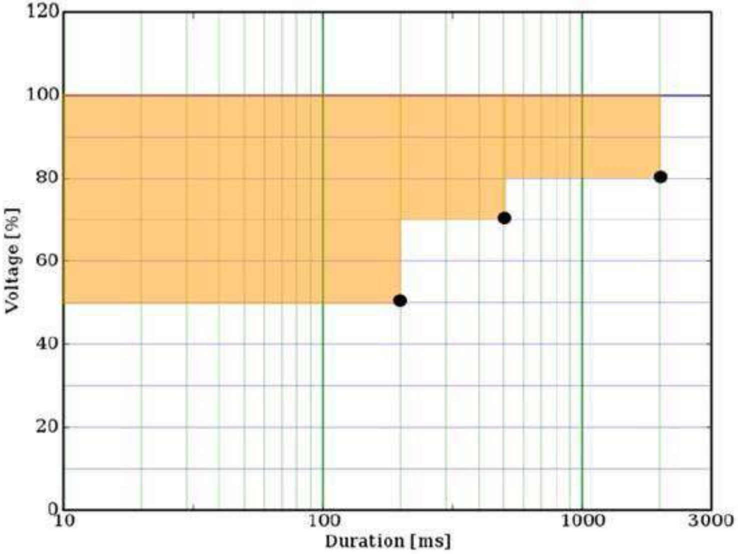

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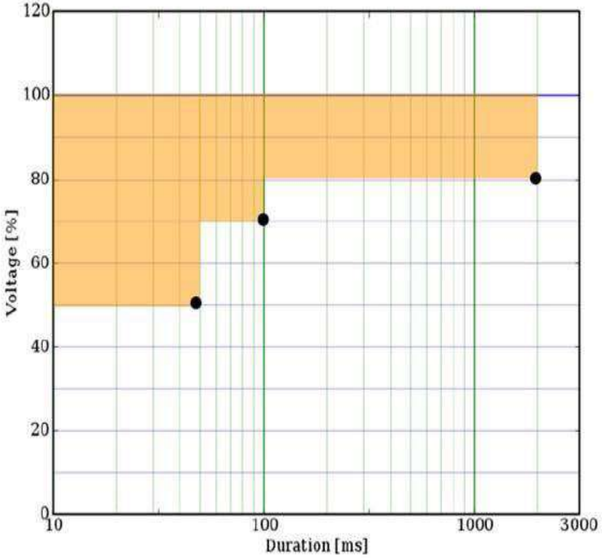

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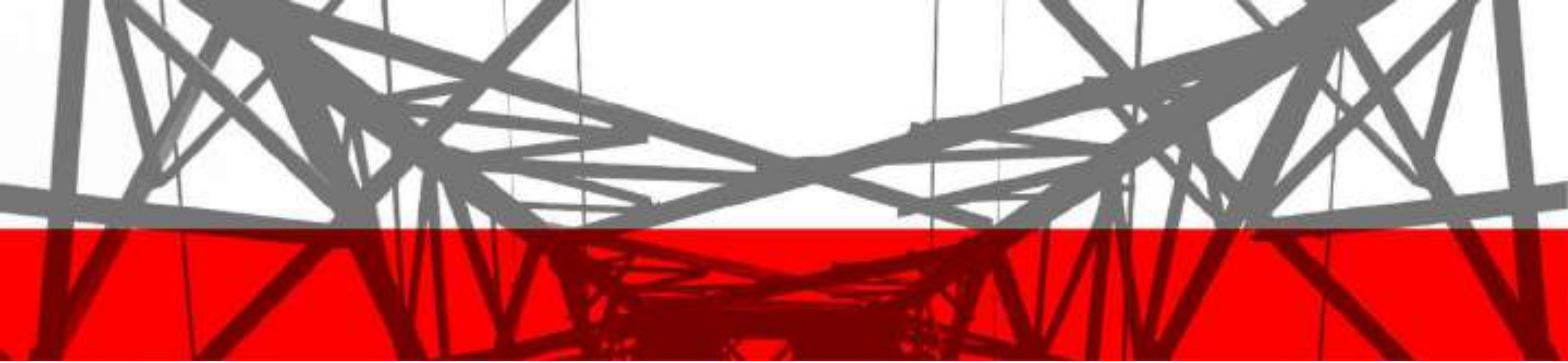
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



POWER QUALITY

Luis Marti

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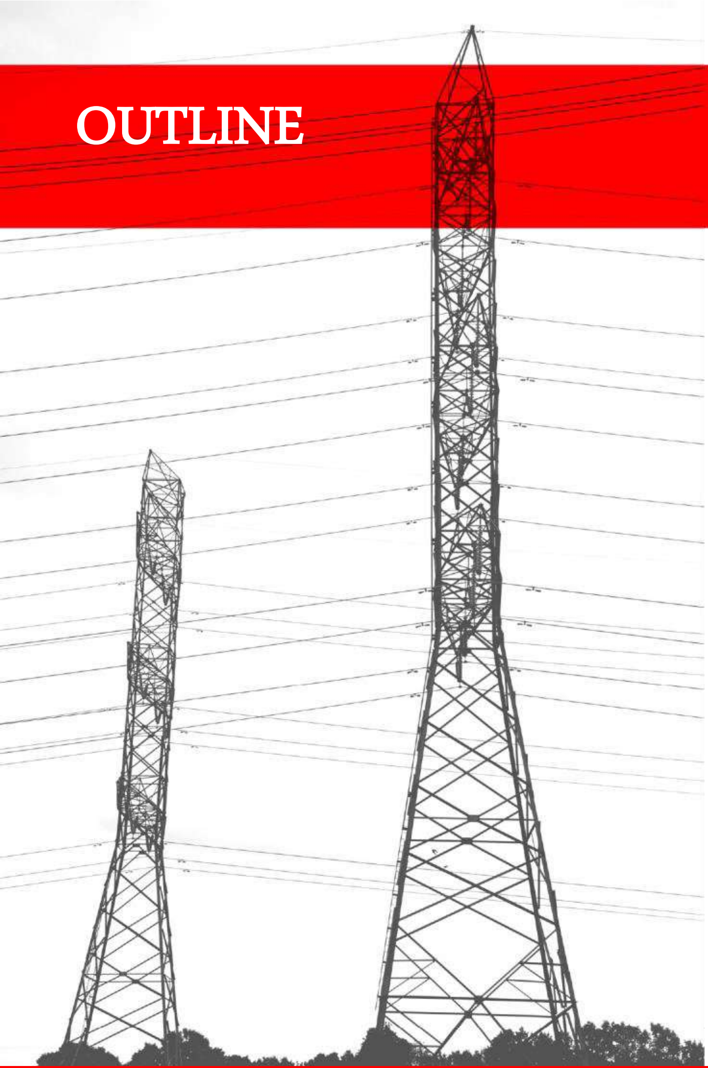
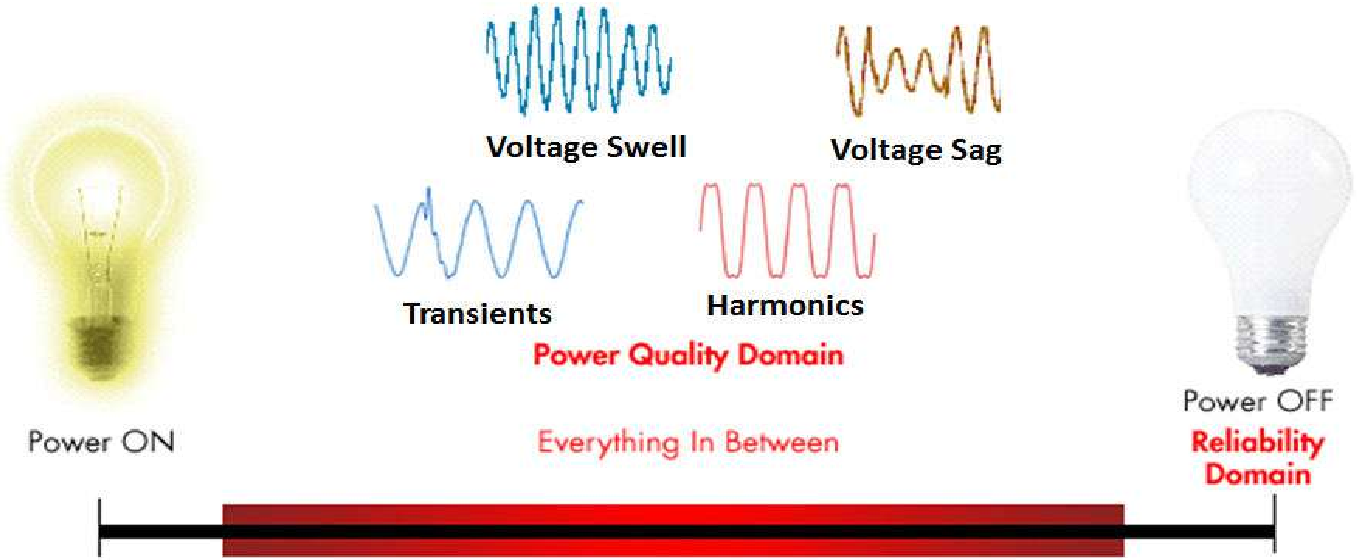


OUTLINE

- Power Quality vs. Reliability
  - Resiliency vs. Delivery Point Interruptions
  - Types of Power Quality issues
  - Voltage Sag
- Initiatives
  - Voltage sag reports
  - Revenue meter leverage
  - PQ audits

POWER QUALITY VS. RELIABILITY



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- Within the Hydro One system, the most common PQ issues that affect loads are:
  - Voltage sag events
  - Transient overvoltages caused by sub-transmission capacitor bank switching. Capacitor bank switching is not an issue in transmission – IPO breakers have been used since the 90s.

- To a lesser extent:
  - Flicker
  - Harmonics

POWER QUALITY

- Momentary % drop in voltage magnitude due to a fault in the system
- System dependent :“zone of influence”
- If customer’s equipment cannot “ride through” the momentary drop in the voltage, equipment would generally disconnect automatically
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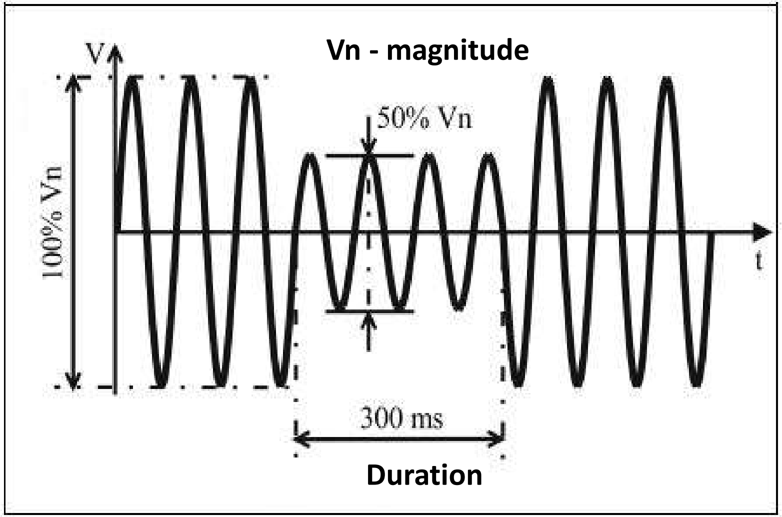

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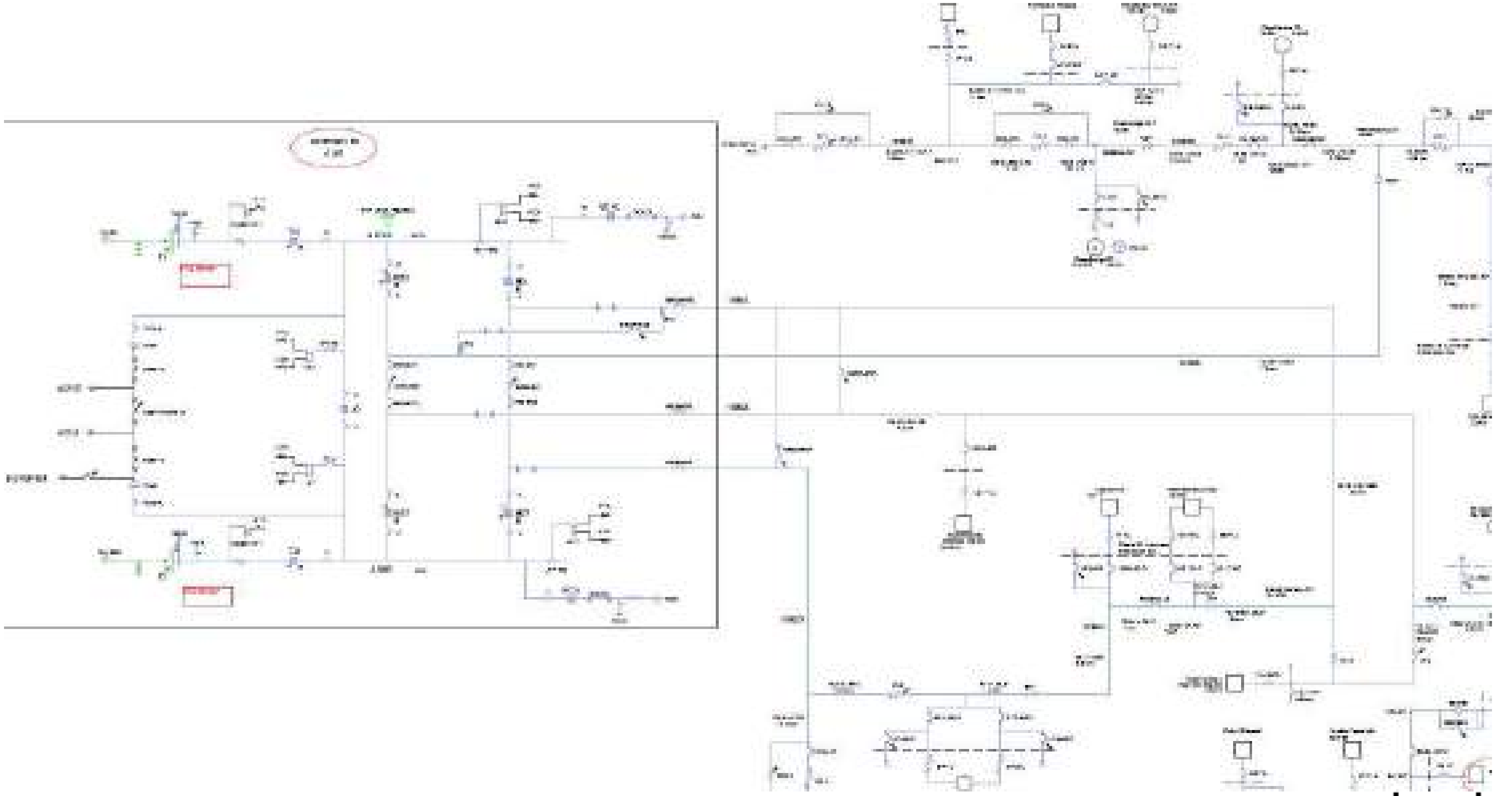

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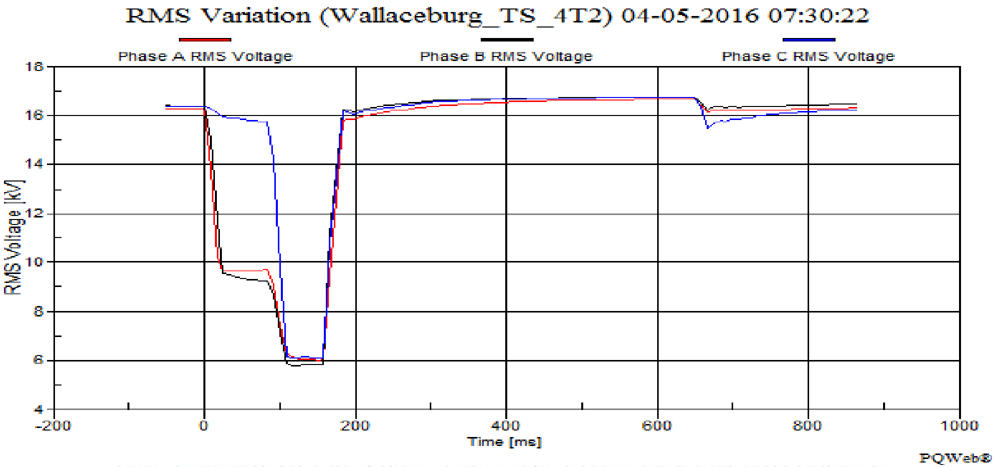
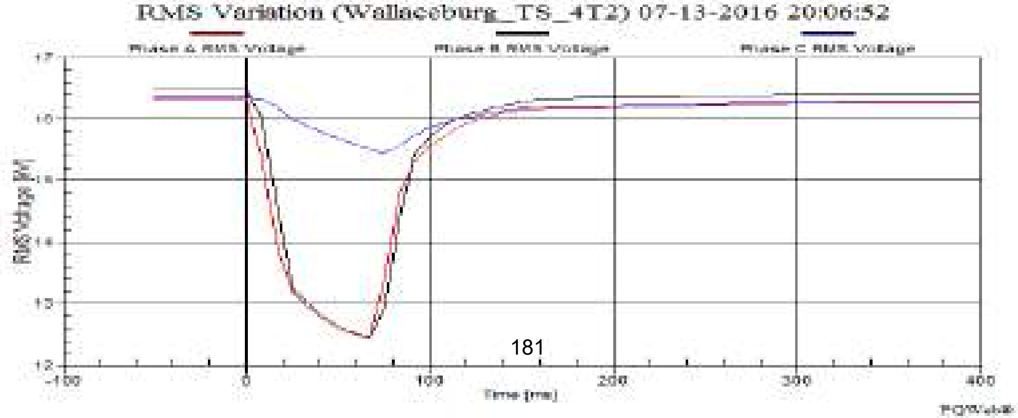
TYPICAL EVENTS CAPTURED





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- It is intended for customers to specify equipment procurement with OEMs. It carefully avoids suggesting any type of required utility / customer interface compatibility or performance

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Table 10 —Recommended test points for Type I and Type II voltage sags

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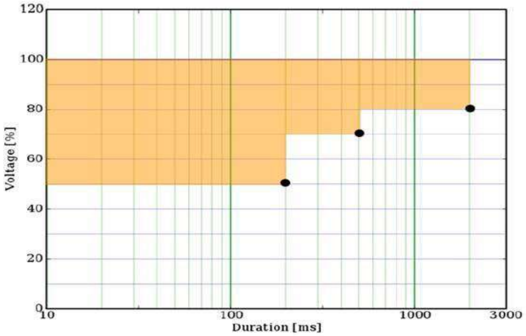

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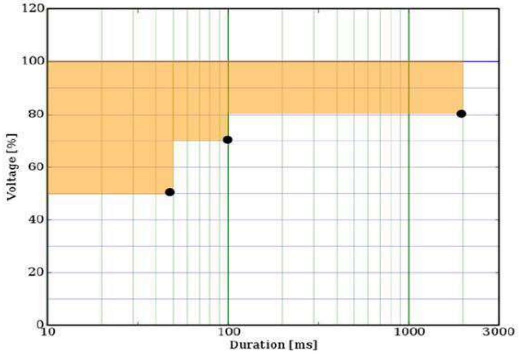

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VOLTAGE SAG (CONT'D)

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- Hydro One's experience is consistent with the findings of EPRI's distributive power quality study (DPQ III): voltage sags are the most common power quality event

- DPQ III showed that a facility is 8 -20 times more likely to receive a voltage sag than an interruption

- The ratio of sags to interruptions found in the DPQ III study based on circuit type:
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    - Sub-Transmission: 20 to 1 (100 kV & > 34.5 kV)
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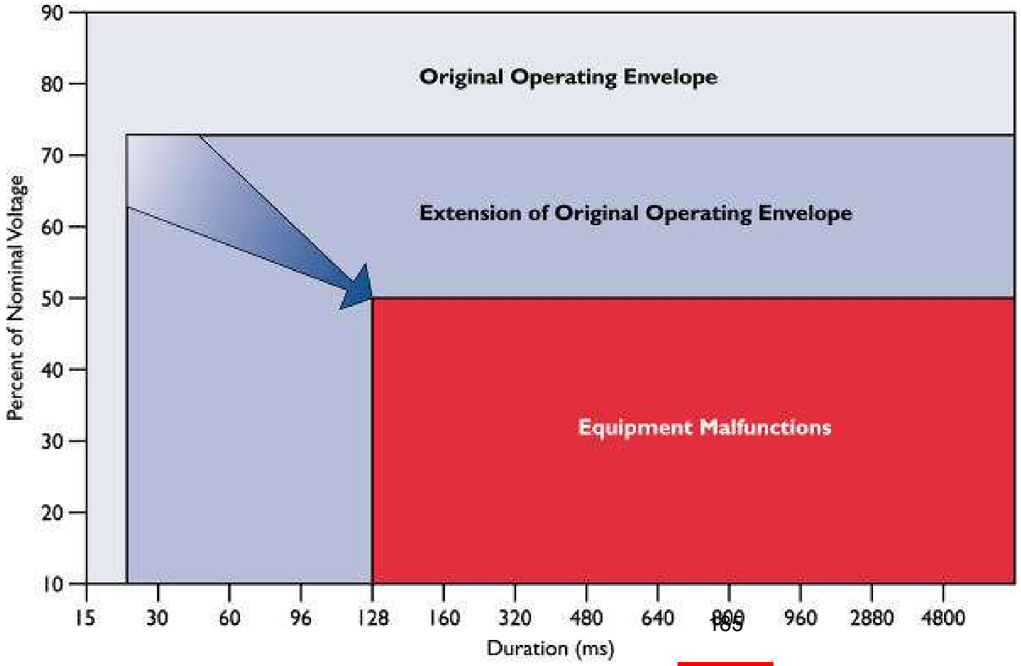
    - Low Voltage: 8 to 1 (< 1 kV)

- Average distribution fed customer site is 15 times more likely to experience a voltage sag than an outage or momentary interruption

RESILIENCE – EXTENDING THE OPERATING ENVELOPE

"Extending the operating envelope" of equipment means reducing the area of equipment malfunctions by enabling the equipment to ride through deeper and longer voltage sags



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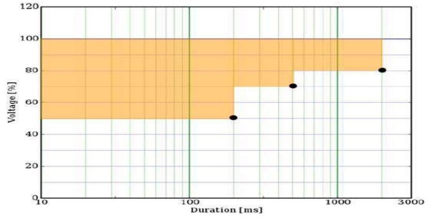

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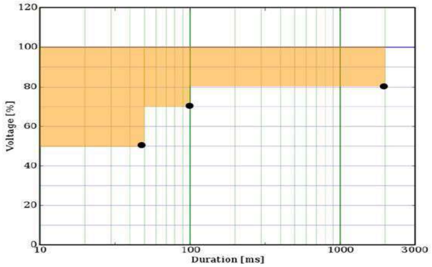
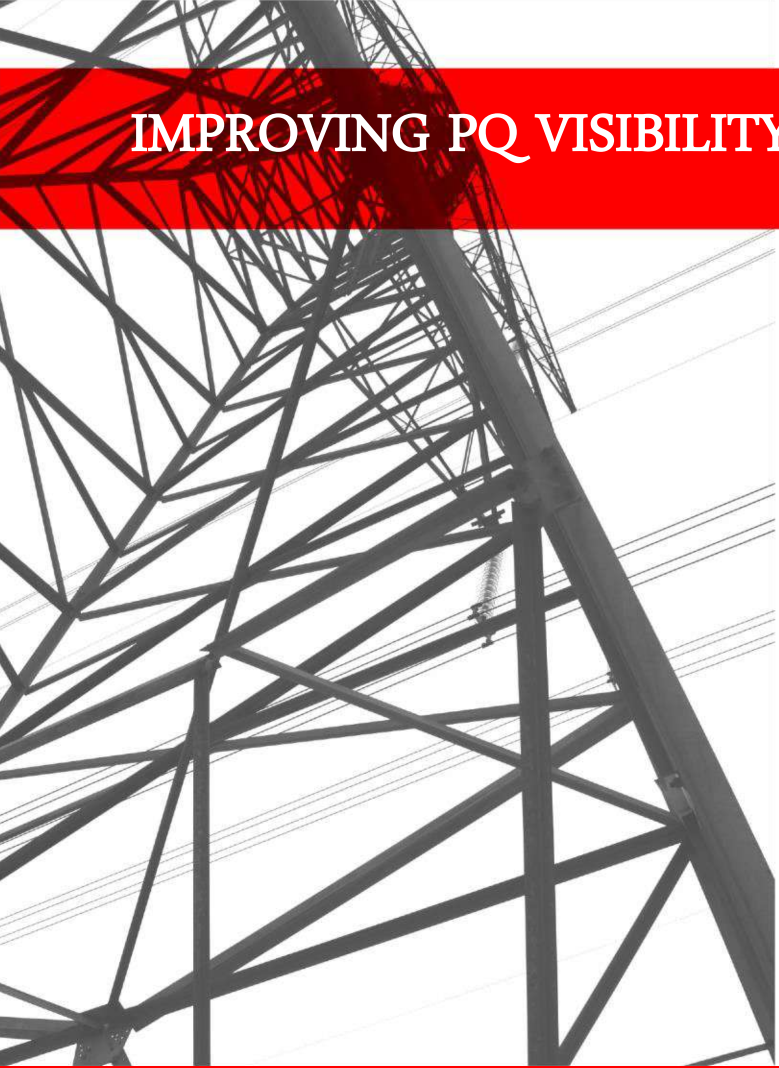


Figure 23—Recommended Type III test levels

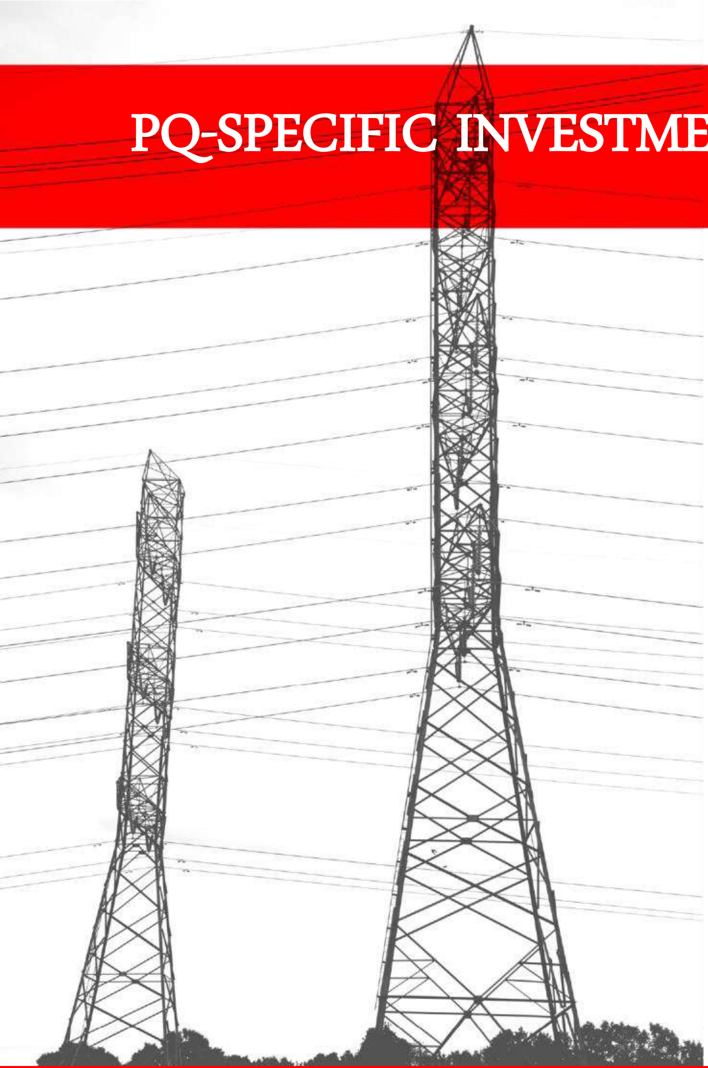
WHAT IS HYDRO ONE DOING ABOUT PQ?



IMPROVING PQ VISIBILITY

1. Increasing visibility of PQ measurements both in Tx and Dx
   - PQ meters installed to date = 345 Tx, 331 Dx (DG)
   - Average installed per year to Dx = 50 (DG)
   - Planned installations for Tx = 49 (by end of 2020)

2. Program to leverage/integrate Customer revenue meters into PQWeb
   (12 to date)



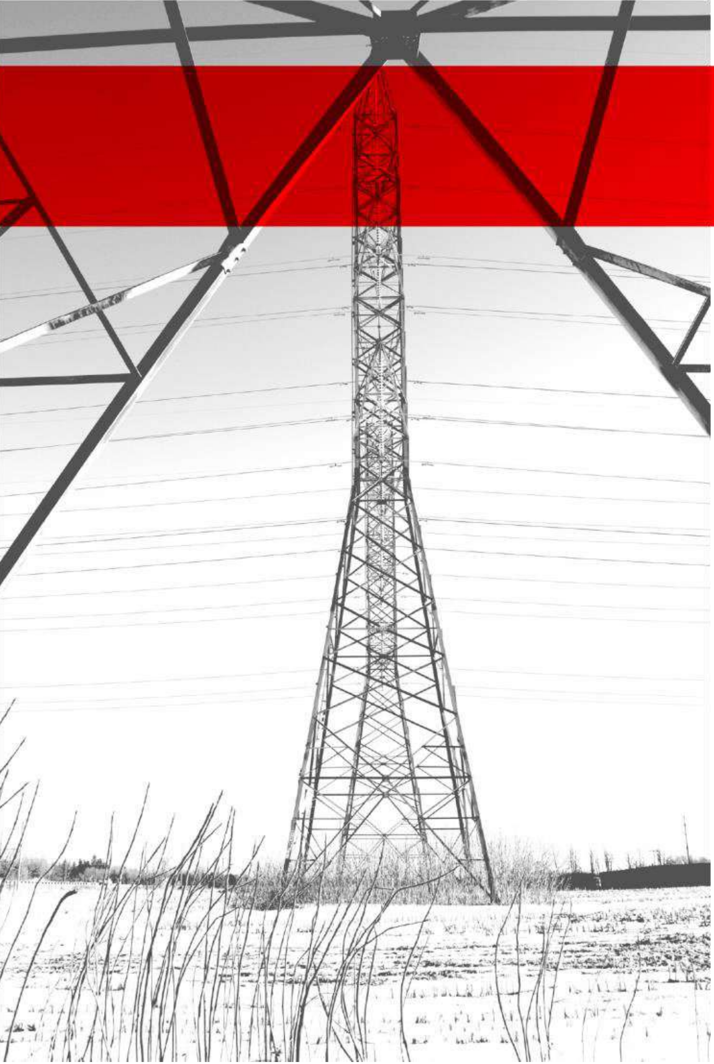
PQ-SPECIFIC INVESTMENTS

1. Dedicated PQ investment drivers

2. Investigate and invest in practical and financially prudent non-reactive measures that improve PQ

    - For example, a pilot to evaluate the performance of 72kV capacitor bank switchers with pre-insertion resistors to reduce switching transients

3. Support of 3rd party Power Quality Audits



WHAT DOES A PQ AUDIT LOOK LIKE?

1. Utility Side Analysis

2. Plant System Analysis and Recommendations

UTILITY-SIDE ANALYSIS:
SARFI DATA

$$SARFI_x = \frac{\sum N_i}{N_T}$$

- System Average RMS (Variation) Frequency Index
- Typically normalized to per site/per year data
- The index provides a count of all events with magnitudes and durations outside or below the index threshold
    - SARFI-70 provides a normalized count of all voltage sags with a retained voltage less than 70% of nominal (regardless of duration) in a time period.
    - SARFI-10 represents a normalized count of the number of interruptions experienced at the site.

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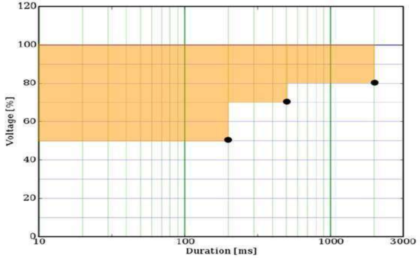

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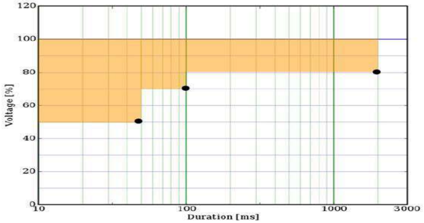
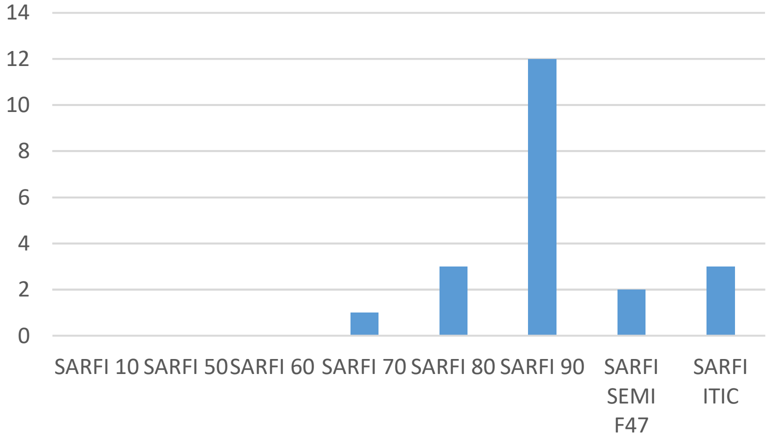


Figure 23—Recommended Type III test levels

SARFI DATA

Import Name	(5/31/2015 - 12/8/2015)	
Event Count	12 total events	
Monitor Years	0.52 years	
Average Sag Magnitude (%)	82.30%	
Average Sag Duration (sec)	0.362s	
Median Sag Magnitude (%)	84.50%	
Median Sag Duration (sec)	0.125s	
	Normalized to 1 Year	Raw Count
SARFI 10	0.0	0
SARFI 50	0.0	0
SARFI 60	0.0	0
SARFI 70	1.9	1
SARFI 80	5.7	3
SARFI 90	22.9	12
SARFI SEMI F47	3.8	2
SARFI ITIC	5.7	3

- This dataset represents only 0.52 years of information
- Takeaways:
  - Data Set Incomplete
  - Average Sag Magnitude 82.3%
  - Average Sag Duration is 0.362 sec
  - Median Sag Magnitude is 84.5%
  - Median Duration is 0.125 sec



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PLANT SIDE ANALYSIS & RECOMMENDATIONS

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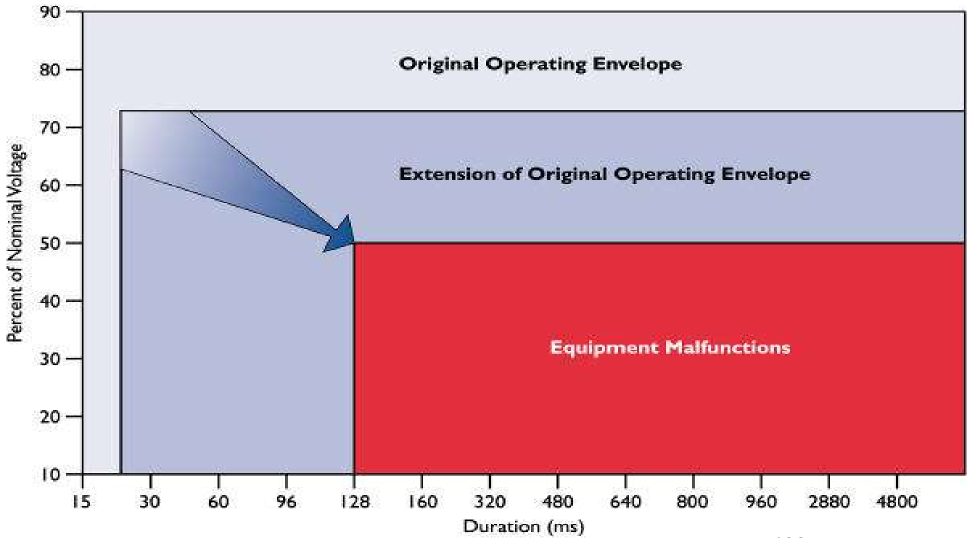

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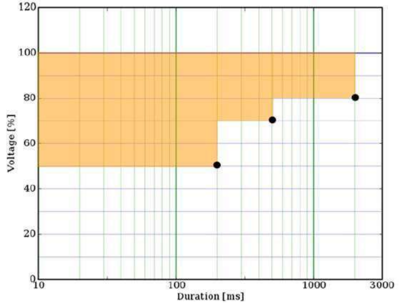

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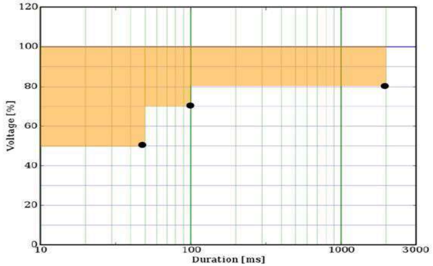
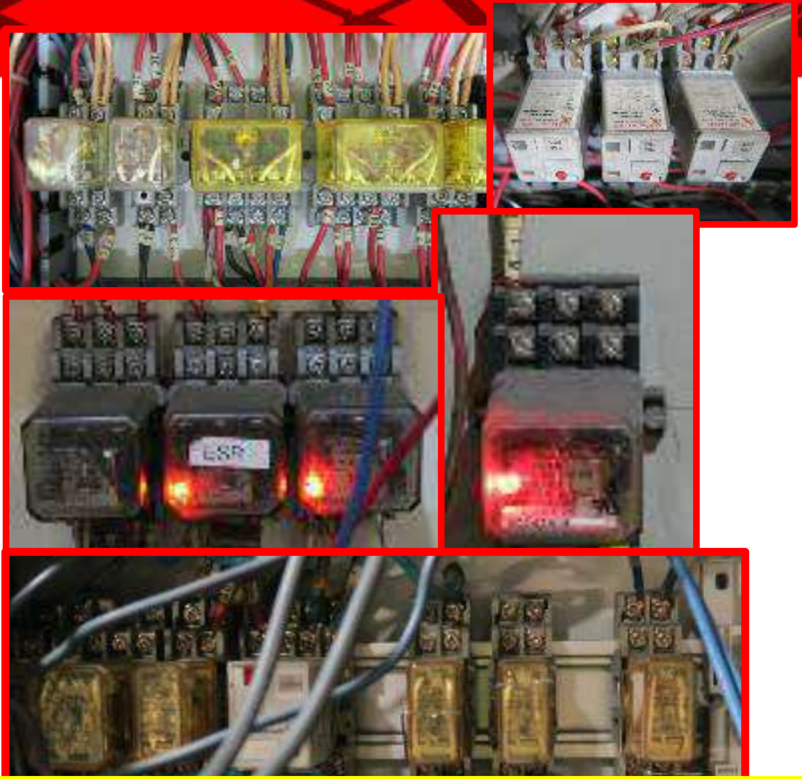


Figure 23—Recommended Type III test levels

KEY FINDINGS FROM [CUSTOMER] ON-SITE AUDIT

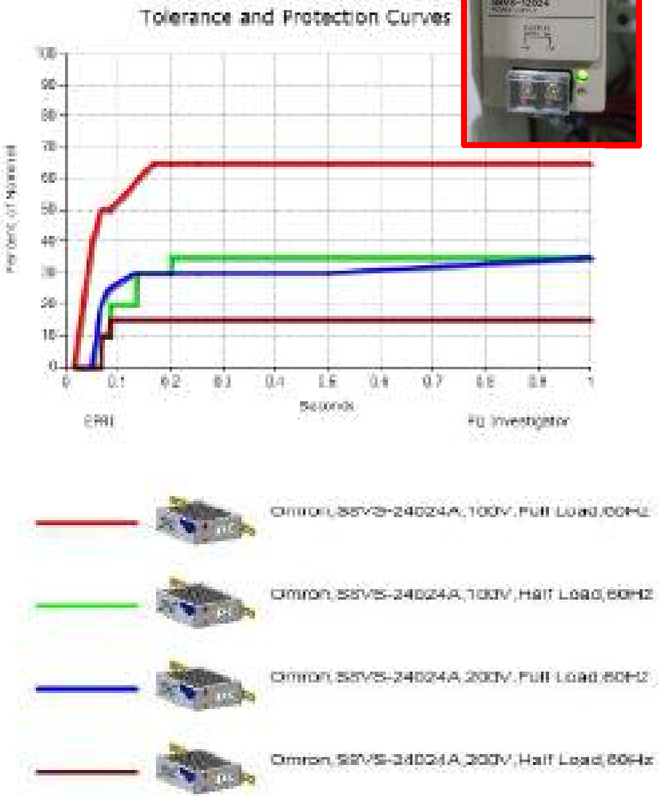
- Most of the process equipment was originally manufactured in the 1990's
  - Equipment has been moved to [customer] from different facilities around the world
  - Equipment has been upgraded on more than one occasion during its 20+ years of service
  - Equipment is largely dependent upon a coordinated drive system.
  - The safety and run permissives of the controls were fed through the contacts of AC Ice Cube relays which are sensitive to voltage sags.
  - The voltage sag ride through of these clear plastic relays is typically 1cycle 72%



Major Finding: Any voltage sag lower than 72% will cause the relay contacts to open and remove run permissive(s), enable signals, and potentially trigger a false Emergency Power Off (EPO).

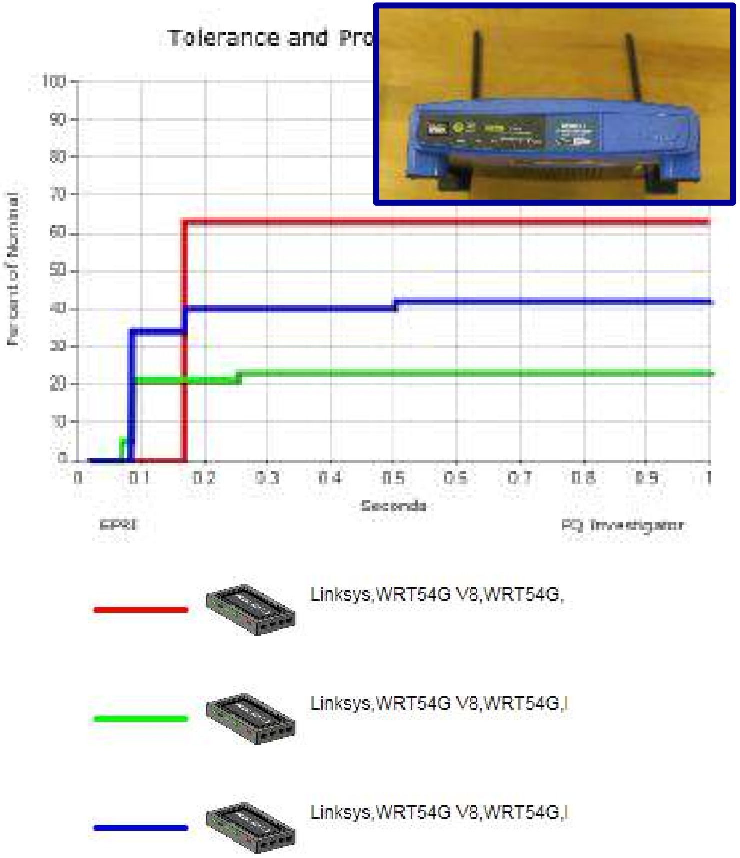
KEY FINDING FROM ON-SITE AUDIT (CONT'D)

- Omron S8VS Series DC Power Supply
  - The facility has chosen the Omron power supply for process control throughout the facility
  - EPRI has tested this power supply and found that the voltage sag ride through varies depending upon AC input voltage and the output DC loading
  - If this power supply is powered 100Vac and loaded 100% the voltage sag ride through is 3cycles 65%.
  - Power Supply Nominal Voltage was ~115Vac
  - If power supply is loaded 50% or below the ride through is reduced to 10 cycles 35% nominal
  - If power supply was powered 200Vac or greater the ride through may be better than 15%.
  - DC Load measurements were not taken therefore the ride through of this power supply was assumed at 100% load



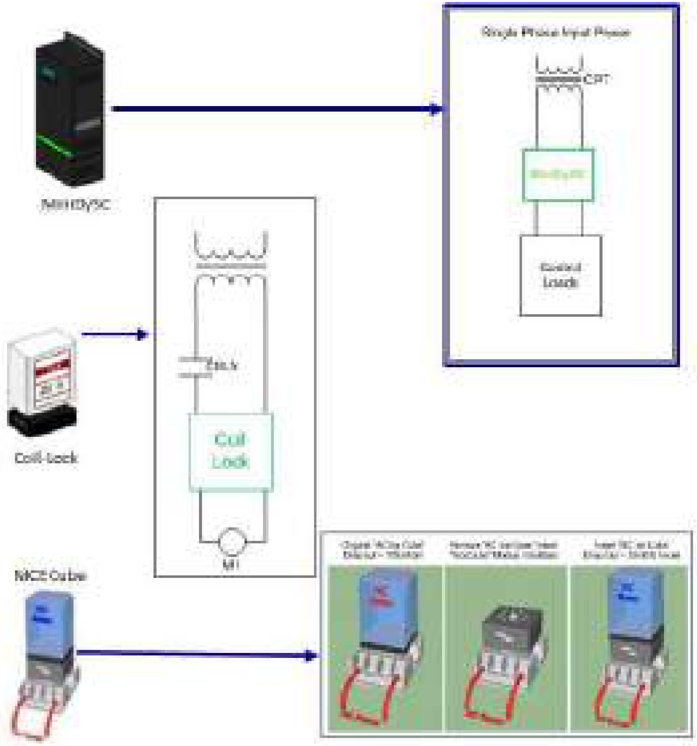
KEY FINDING FROM ON-SITE AUDIT (CONT'D)

- The equipment has been upgraded on several occasions
- The newest ASDs in the facility communicate through local area network hubs LAN
- These hubs were powered through the service outlets in the cabinets
- May times these service outlets are not powered from the same source as the controls
- Some of these hubs are sourced through outlet style plug in power supplies.
- EPRI tested a router using three different power supplies.
    - The results were drastically different.
    - The power supply with the highest current rating actually produced the worst voltage sag ride through performance.



TYPES OF VOLTAGE SAG
PQ SOLUTIONS

- MiniDySC
  - Static Series Compensator with Capacitor Storage
  - Control Circuit Mitigation
  - 50ms of voltage interruption (more time at reduced load)
- 5 seconds of voltage sag protection to 50% nominal
  - Coil Lock
  - Relay Coil Solution
  - Size based upon coil resistance
  - 3 seconds of voltage sag protection to 25% nominal
- Nice Cube
  - 8 pin octal Ice Cube Relay Solution
  - Direct replacement for 120Vac and 24Vac octal relays
  - 3 seconds of voltage sag protection to 30% nominal



COMPARISON OF VOLTAGE SAG VS. INTERRUPTION SOLUTIONS

Voltage Sag Solutions

- Pros
  - Lower Cost
  - Less Maintenance
- Cons
  - Less ride through time
  - Protects for voltage sags only
  - Some solutions will protect for a couple cycles of voltage interruption

Interruption Solutions

- Pros
  - Longer ride through time
  - Protection to 0 volts
- Cons
  - Higher cost
  - Ultra Capacitor UPS requires fan maintenance

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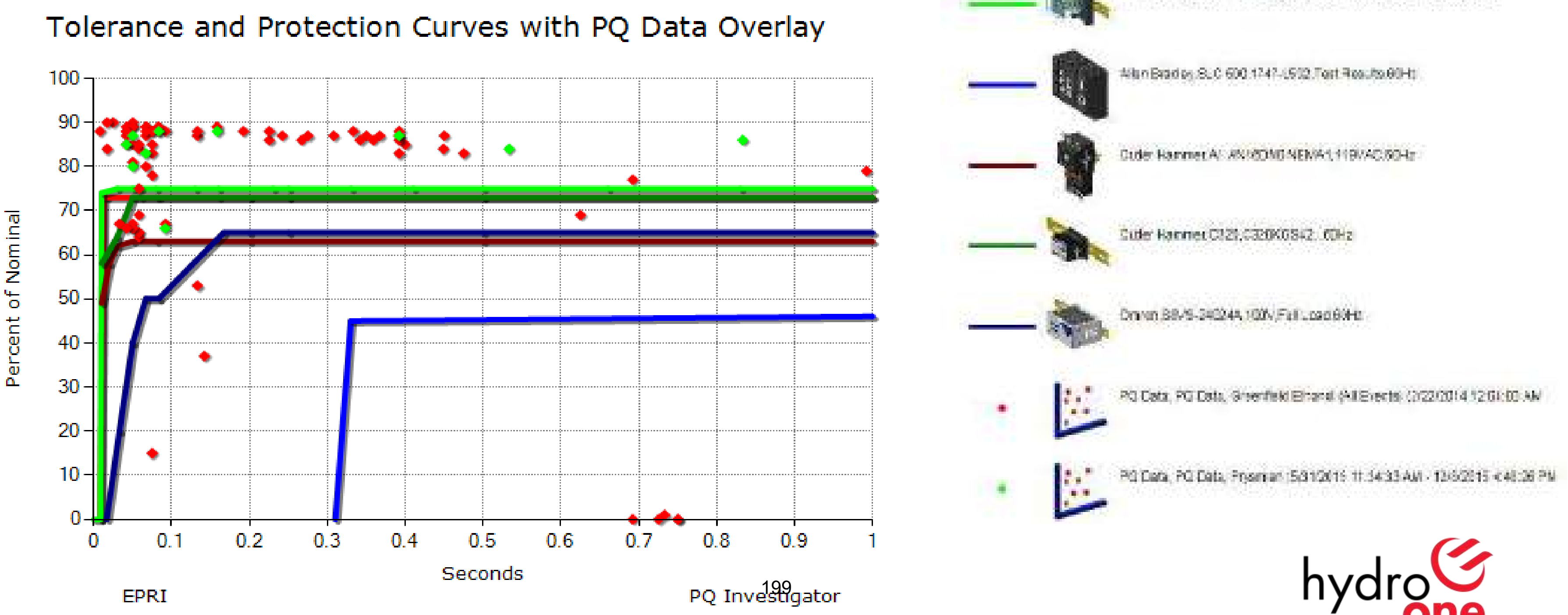
PQ DATA VS. EQUIPMENT SUSCEPTIBILITY

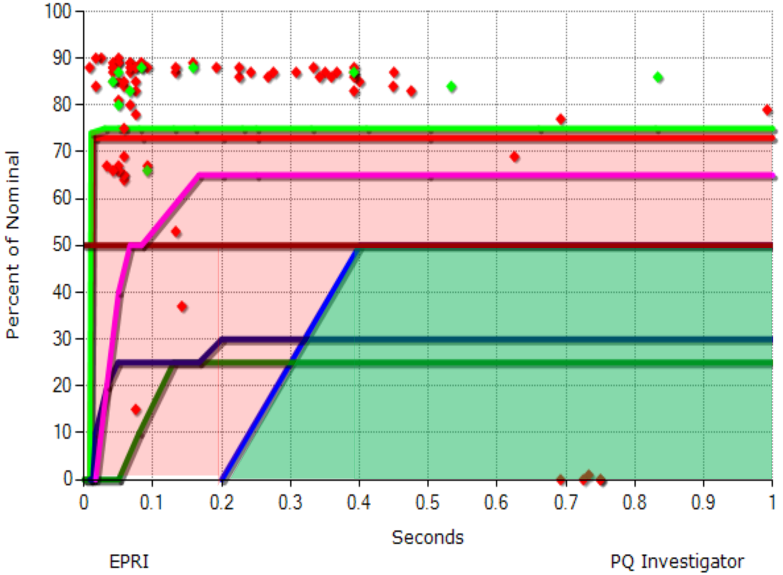
The majority of the control components that were observed during the audit are included in the graphic below.



PQ DATA WITH EQUIPMENT SUSCEPTIBILITY AND MITIGATOR

The solutions shown are designed to protect for voltage sags.

Tolerance and Protection Curves with PQ Data Overlay



Original Susceptibility of Controls

Susceptibility of Controls with MiniDySC

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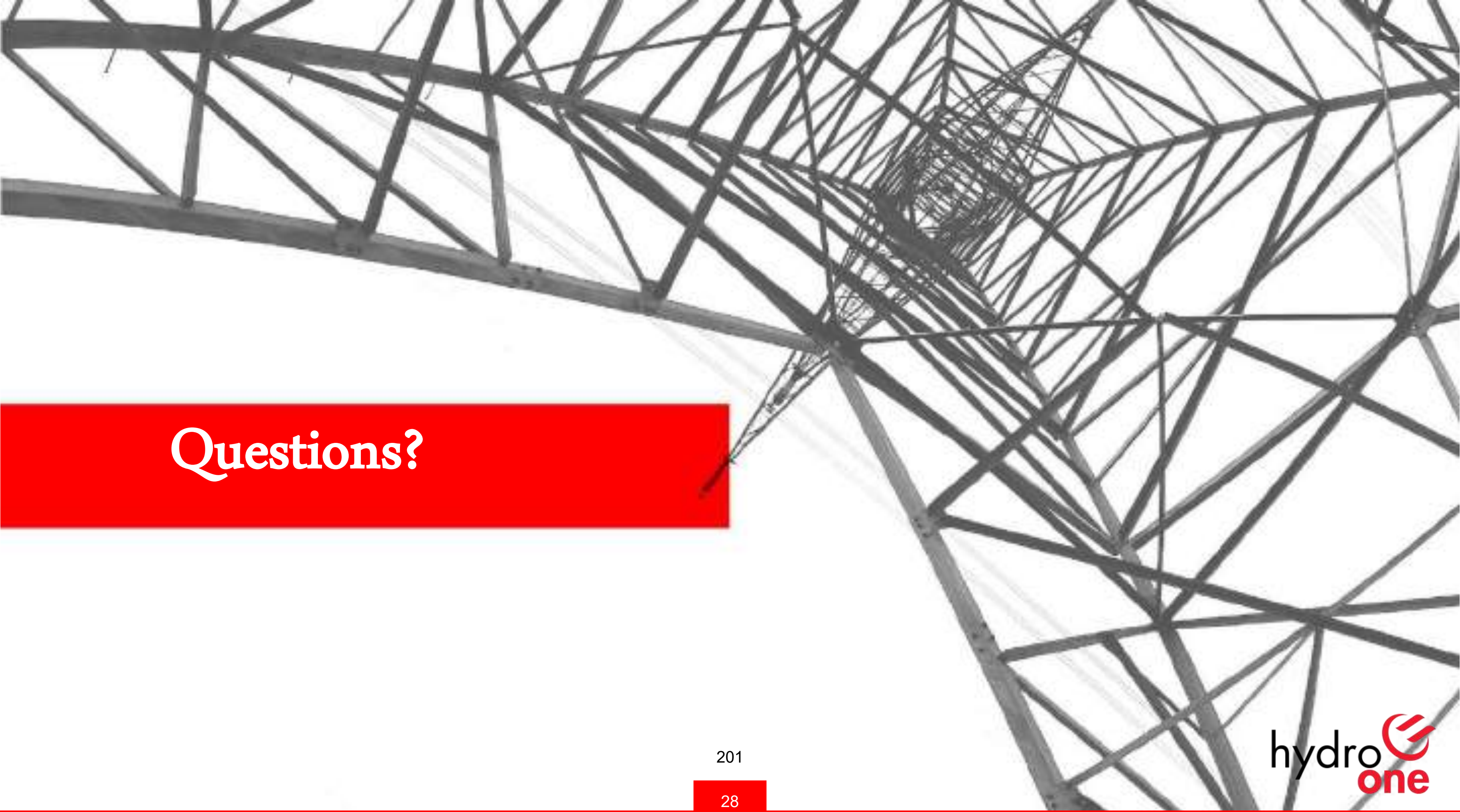
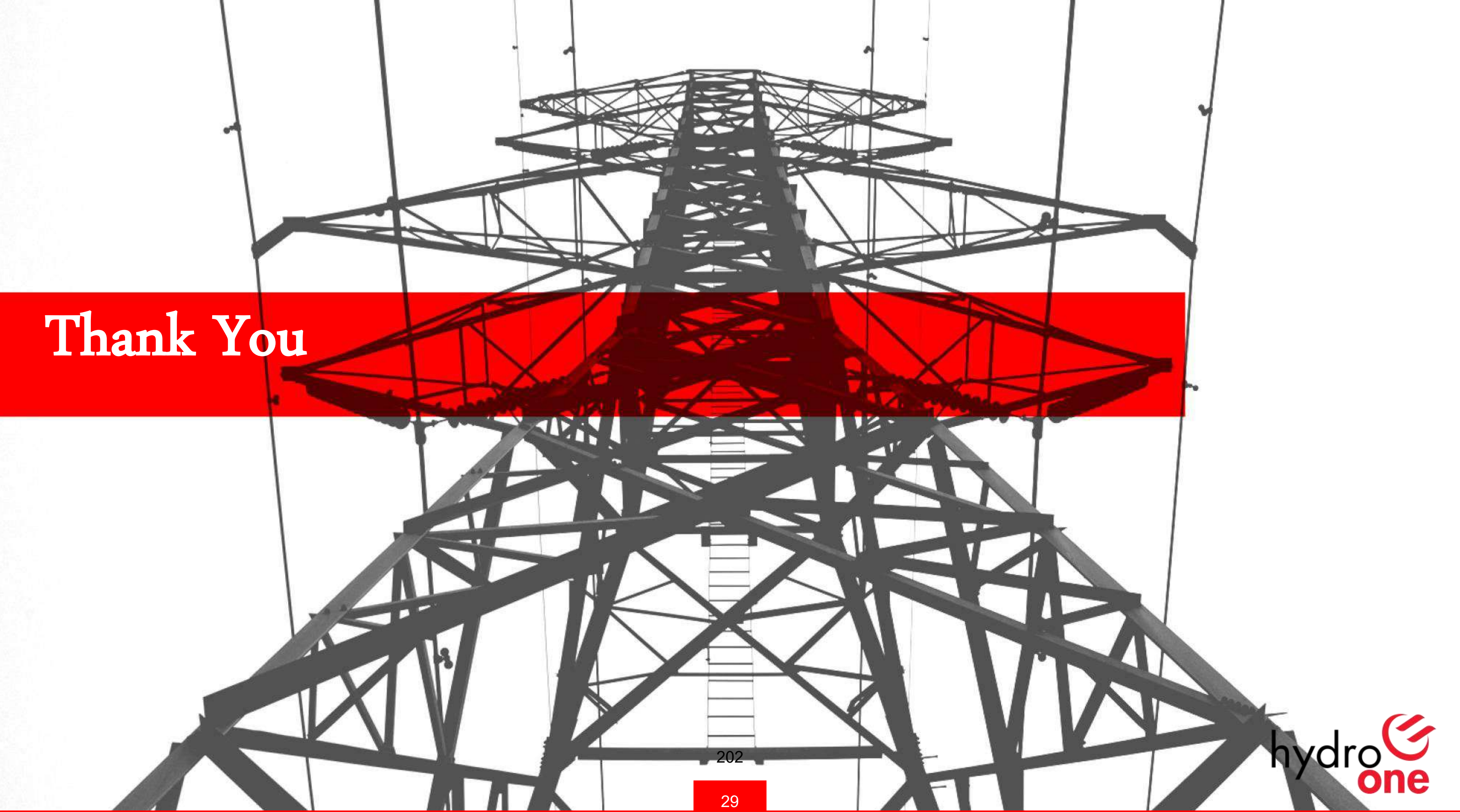


Questions?

Thank You



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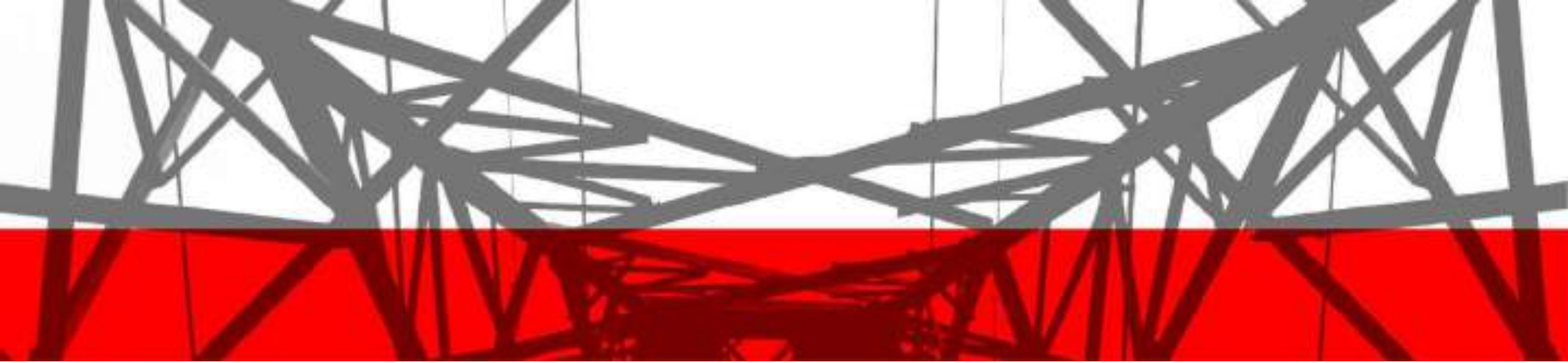
LARGE CUSTOMER CONFERENCE

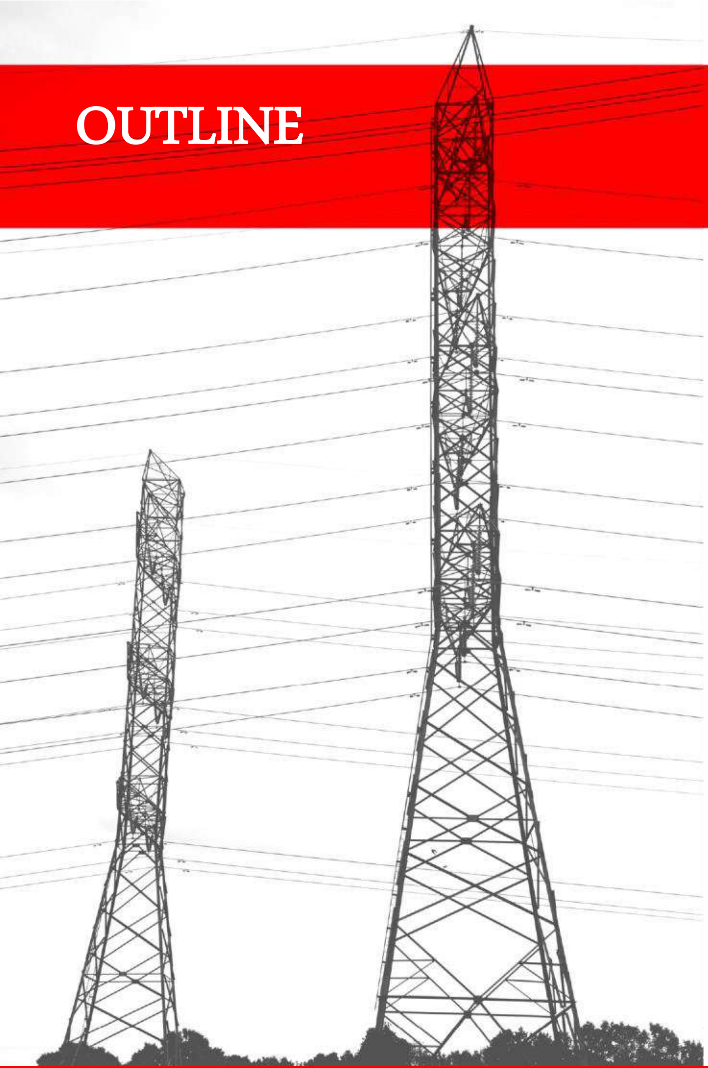
Productivity & Operational Efficiency



POWER QUALITY

Luis Marti

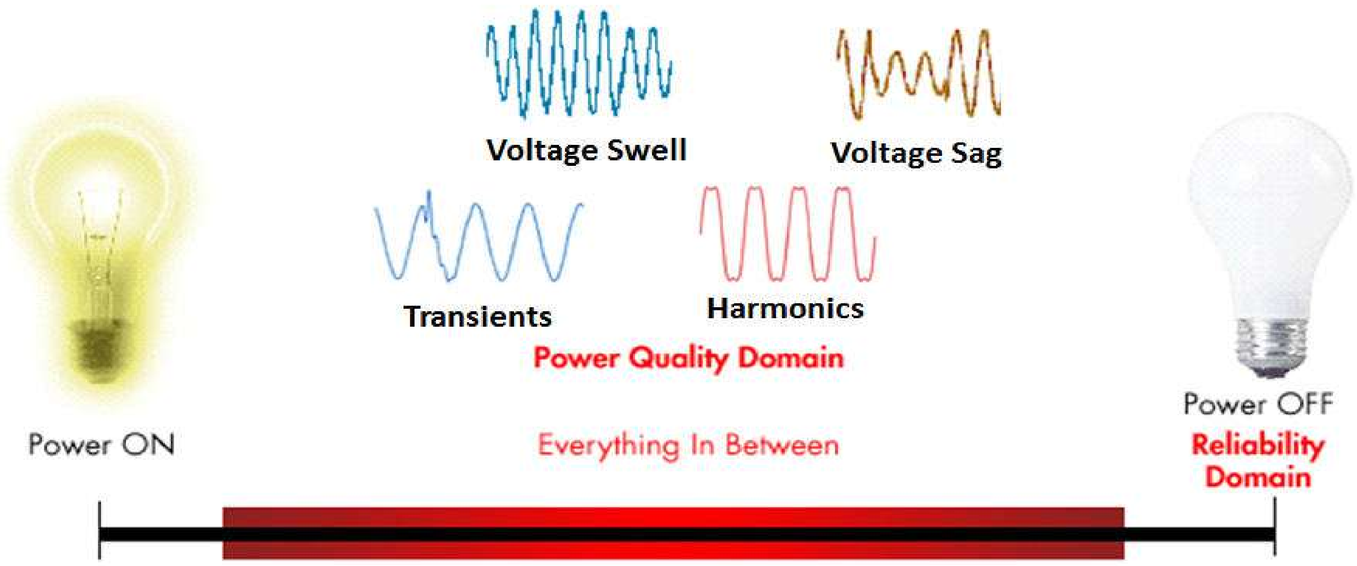
Director, Reliability Studies, Power Quality, RD&D



OUTLINE

- Power Quality vs. Reliability
  - Resiliency vs. Delivery Point Interruptions
  - Types of Power Quality issues
  - Voltage Sag
- Initiatives
  - Voltage sag reports
  - Revenue meter leverage
  - PQ audits

POWER QUALITY VS. RELIABILITY



Traditional Reliability Measures

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

POWER QUALITY

- Power Quality (PQ) is a term used to describe harmonics, flicker, voltage imbalance, transients etc., excluding Delivery Point interruptions

- Formal PQ Definition: "Any problem that is manifested in voltage, current or frequency deviations [or tripping] that result in failure or misoperation of utility or end user equipment"

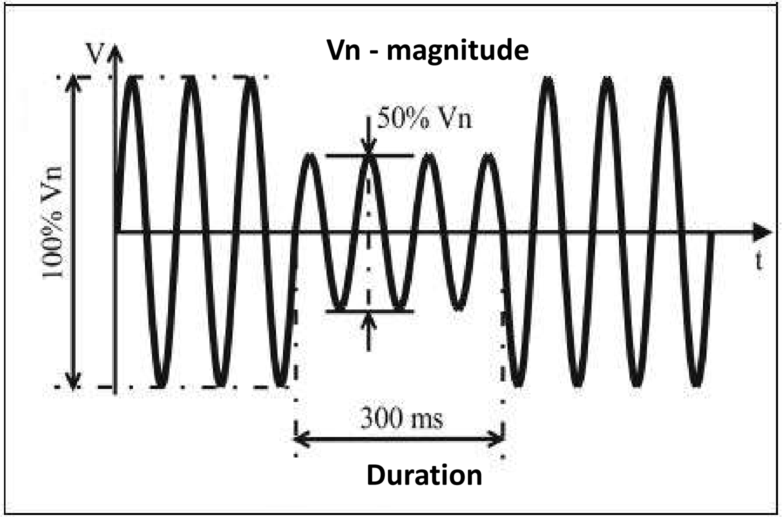
- PQ events can have high cost impact for industrial customers depending on the individual plant and internal processes

- Within the Hydro One system, the most common PQ issues that affect loads are:
  - Voltage sag events
  - Transient overvoltages caused by sub-transmission capacitor bank switching. Capacitor bank switching is not an issue in transmission – IPO breakers have been used since the 90s.

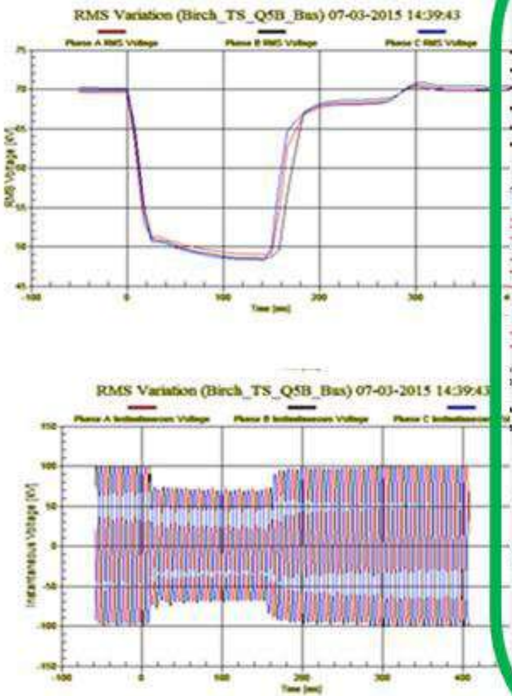
- To a lesser extent:
  - Flicker
  - Harmonics

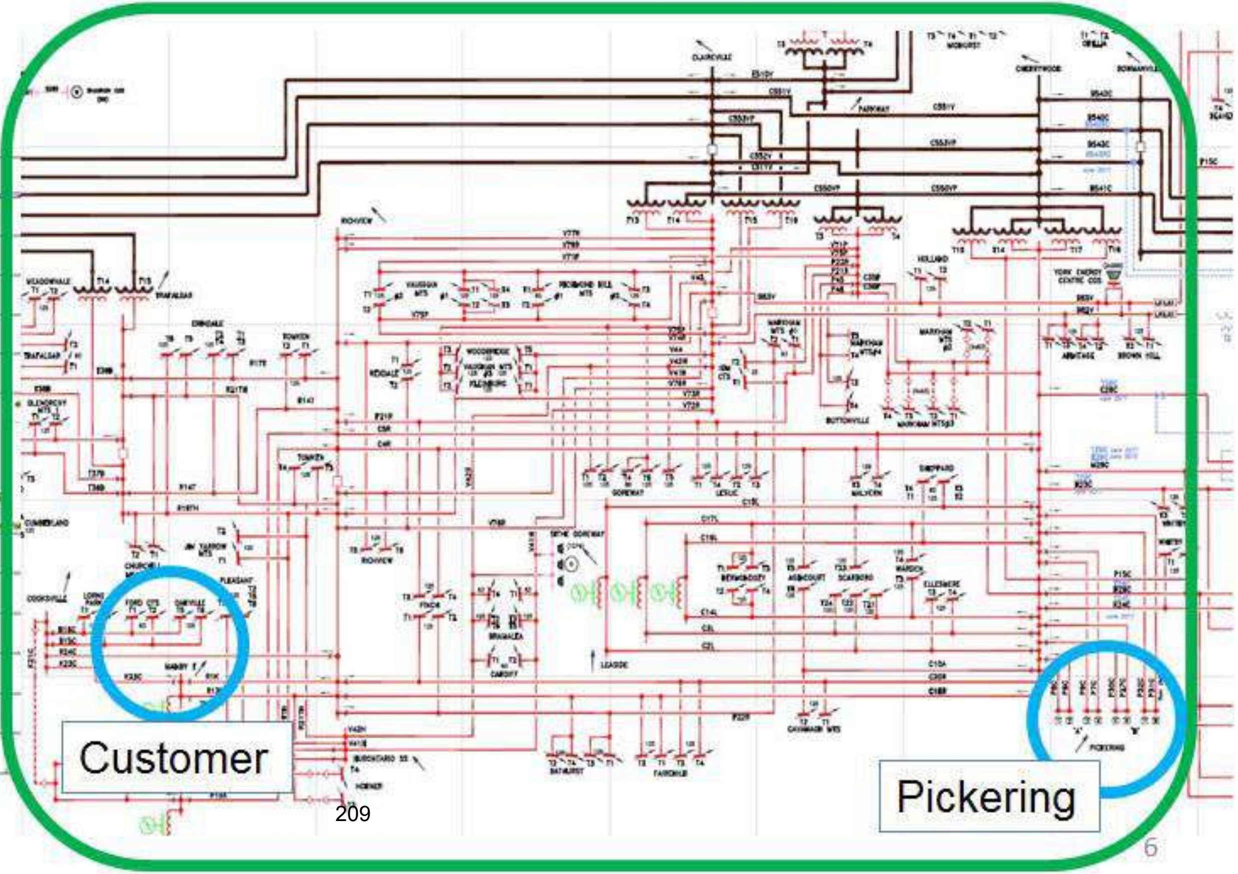
POWER QUALITY

- Momentary % drop in voltage magnitude due to a fault in the system
- System dependent :“zone of influence”
- If customer’s equipment cannot “ride through” the momentary drop in the voltage, equipment would generally disconnect automatically
- Unlike delivery point interruptions (which are a measure of system reliability), the effects of voltage sag events are a combination of:
  - Severity of the sag
  - Duration of the sag
  - Resilience of the load



A FAULT WITHIN THE ZONE OF INFLUENCE CAN CAUSE A VOLTAGE SAG EVENT AT A CUSTOMER'S SITE





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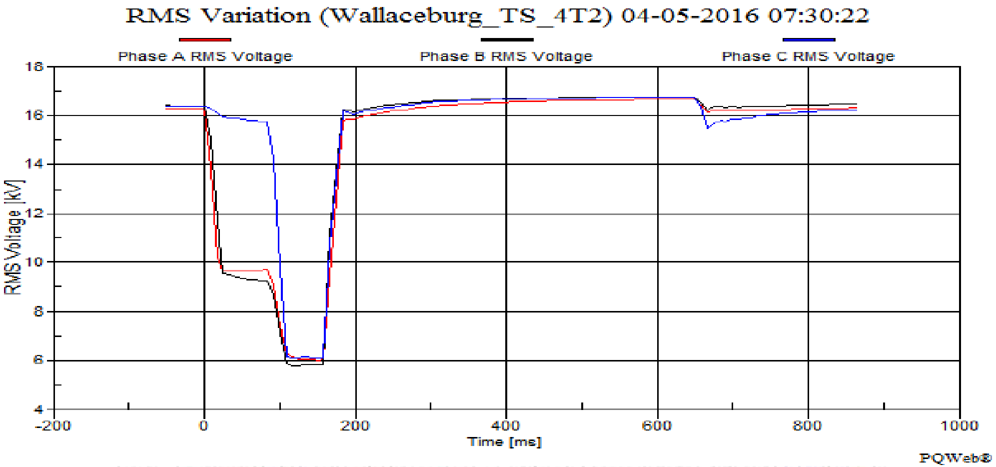
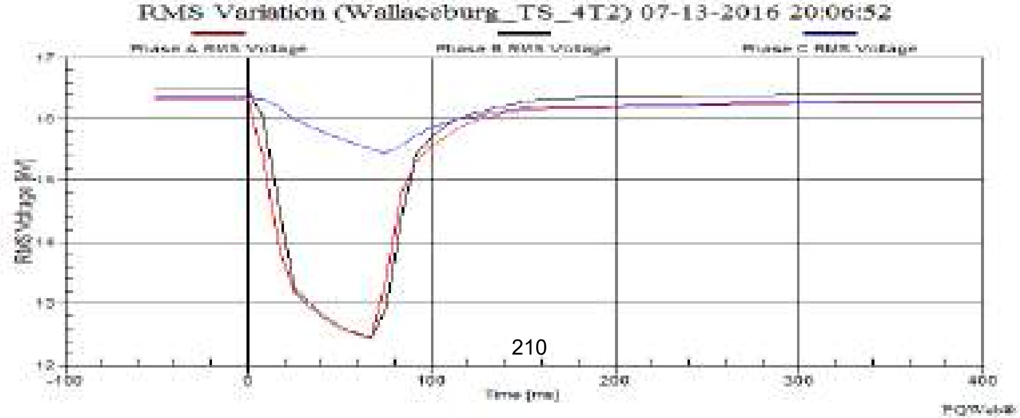
TYPICAL EVENTS CAPTURED





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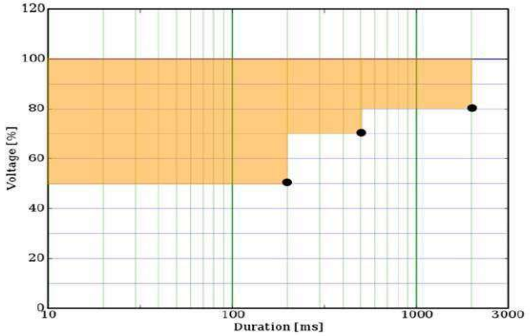

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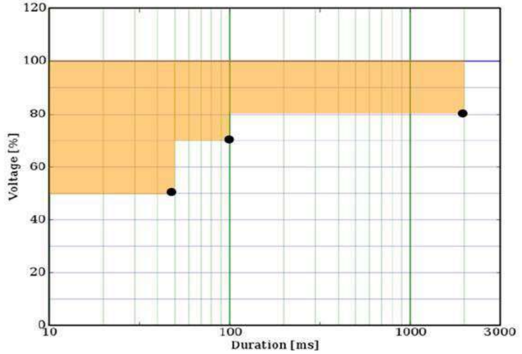

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VOLTAGE SAG (CONT'D)

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PQ VS. DELIVERY POINT PERFORMANCE

- Hydro One's experience is consistent with the findings of EPRI's distributive power quality study (DPQ III): voltage sags are the most common power quality event

- DPQ III showed that a facility is 8 -20 times more likely to receive a voltage sag than an interruption

- The ratio of sags to interruptions found in the DPQ III study based on circuit type:
  - Transmission: 8 to 1 (> 100 kV)
  - Sub-Transmission: 20 to 1 (100 kV & > 34.5 kV)
  - Distribution: 15 to 1 (< 34.5 & > 1 kV)
  - Low Voltage: 8 to 1 (< 1 kV)

- Average distribution fed customer site is 15 times more likely to experience a voltage sag than an outage or momentary interruption

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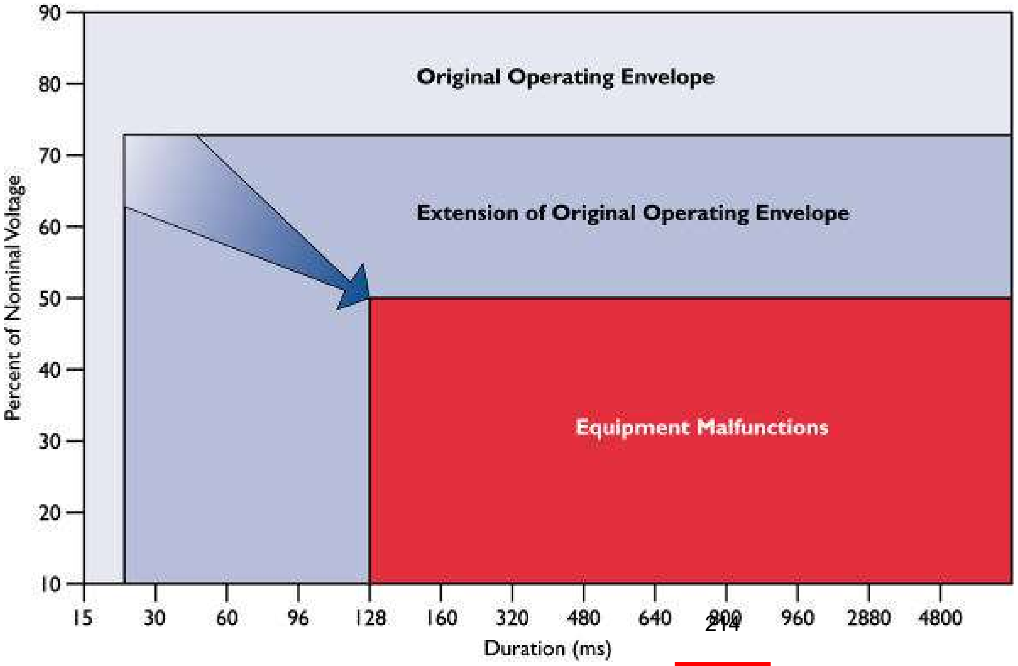

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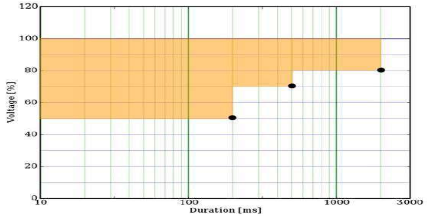

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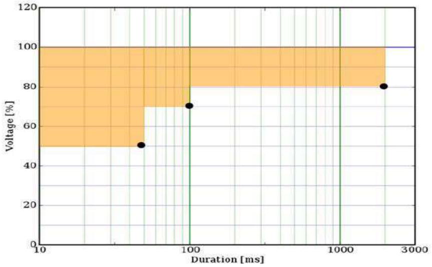
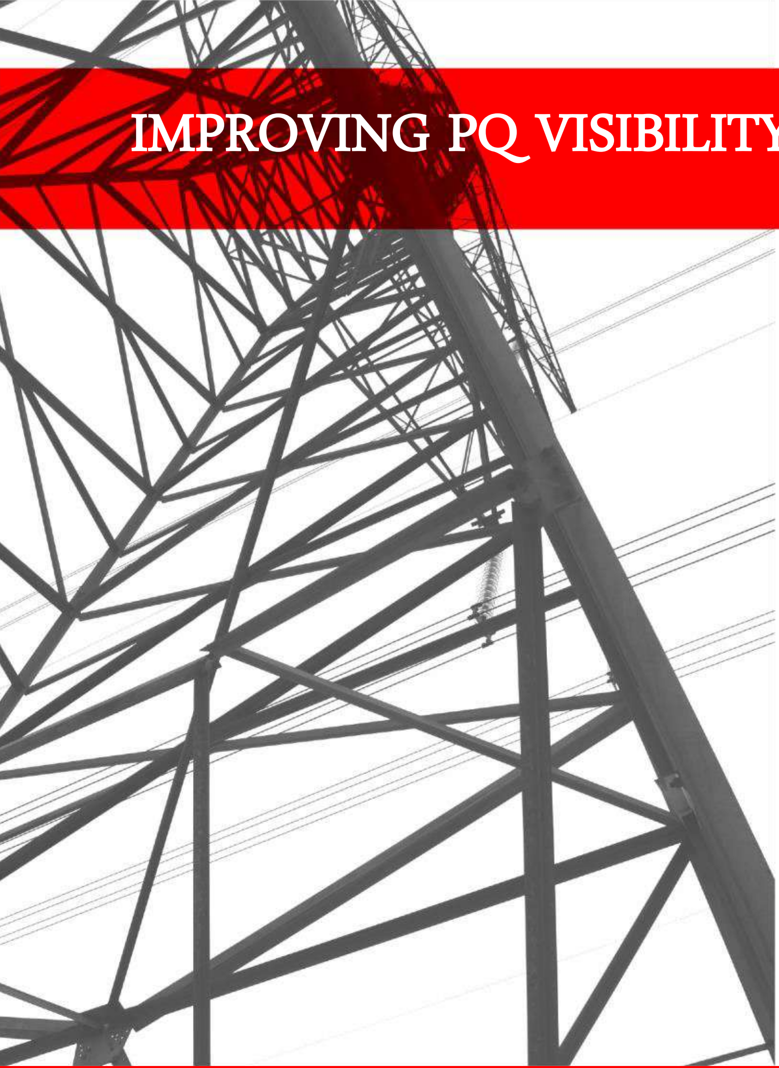


Figure 23—Recommended Type III test levels

WHAT IS HYDRO ONE DOING ABOUT PQ?

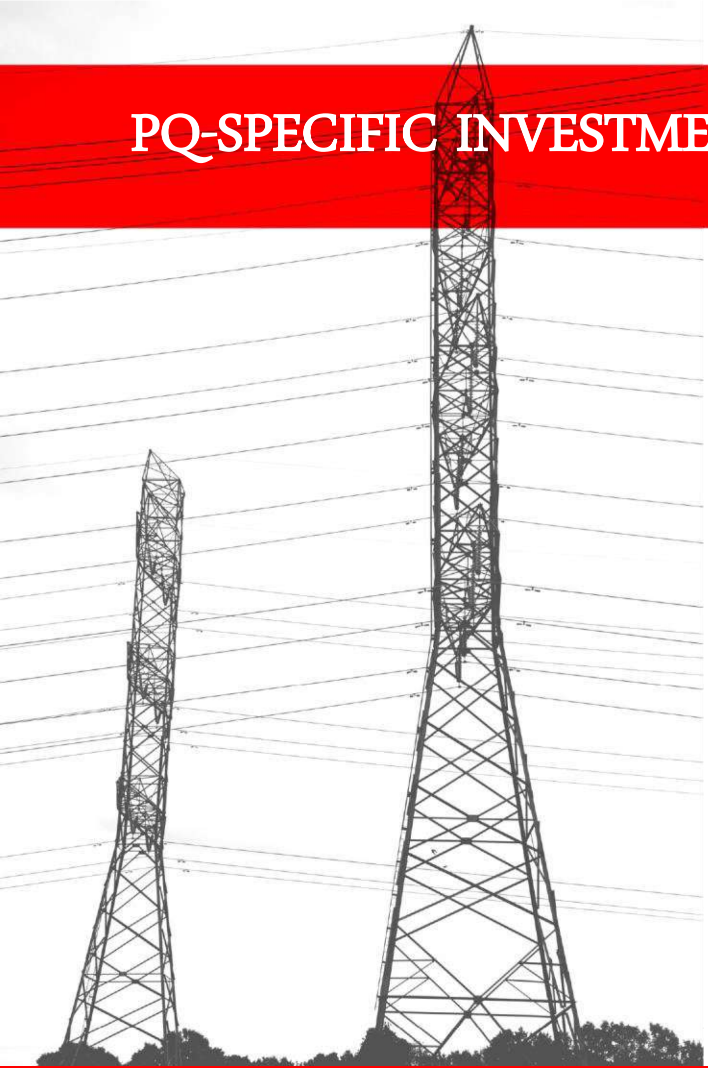


IMPROVING PQ VISIBILITY

1. Increasing visibility of PQ measurements both in Tx and Dx
   - PQ meters installed to date = 345 Tx, 331 Dx (DG)
   - Average installed per year to Dx = 50 (DG)
   - Planned installations for Tx = 49 (by end of 2020)

2. Program to leverage/integrate Customer revenue meters into PQWeb
   (12 to date)

PQ-SPECIFIC INVESTMENTS

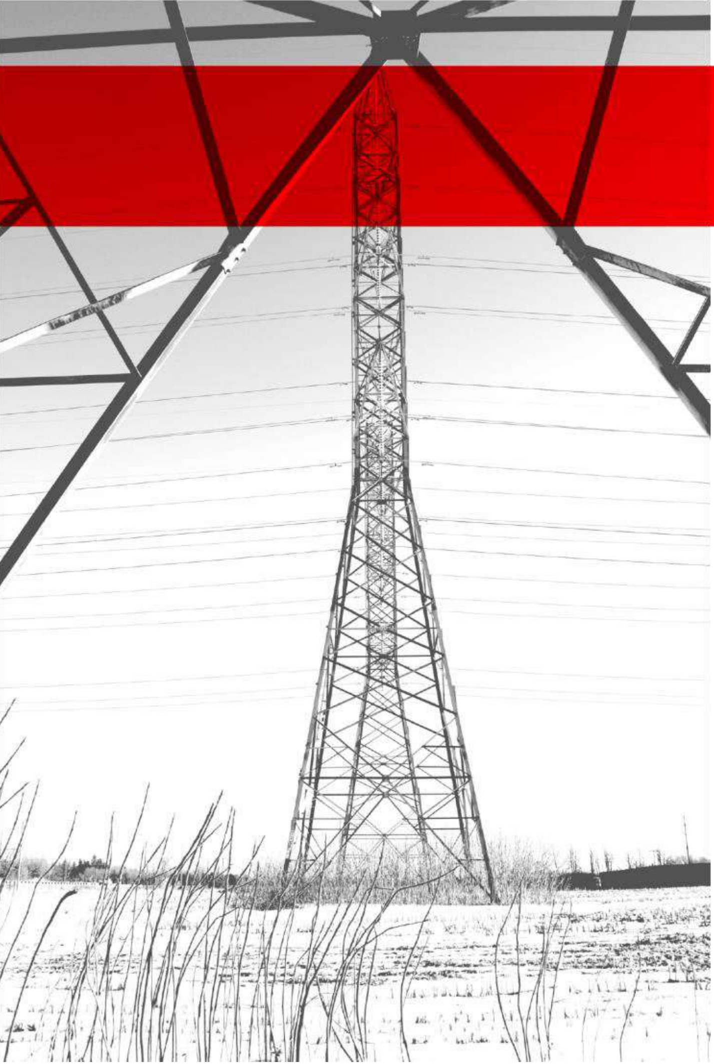


1. Dedicated PQ investment drivers

2. Investigate and invest in practical and financially prudent non-reactive measures
   that improve PQ

   - For example, a pilot to evaluate the performance of 72kV capacitor bank switchers with pre-insertion resistors to reduce switching transients.

3. Support of 3rd party Power Quality Audits



WHAT DOES A PQ AUDIT LOOK LIKE?

1. Utility Side Analysis

2. Plant System Analysis and Recommendations

UTILITY-SIDE ANALYSIS:
SARFI DATA

$$SARFI_x = \frac{\sum N_i}{N_T}$$

- System Average RMS (Variation) Frequency Index
- Typically normalized to per site/per year data
- The index provides a count of all events with magnitudes and durations outside or below the index threshold
    - SARFI-70 provides a normalized count of all voltage sags with a retained voltage less than 70% of nominal (regardless of duration) in a time period
    - SARFI-10 represents a normalized count of the number of interruptions experienced at the site

Table 10—Recommended test points for Type I and Type II voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.2	10 cycles	12 cycles
2	70%	0.5	25 cycles	30 cycles
3	80%	2.0	100 cycles	120 cycles

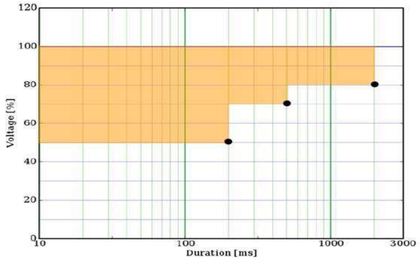


Figure 22—Recommended Type I and Type II test levels

Table 11—Recommended test points for Type III voltage sags

Minimum test point No.	Residual voltage in percent nominal	Duration in seconds	Duration at 50 Hz	Duration at 60 Hz
1	50%	0.05	2.5 cycles	3 cycles
2	70%	0.1	5 cycles	6 cycles
3	80%	2.0	100 cycles	120 cycles

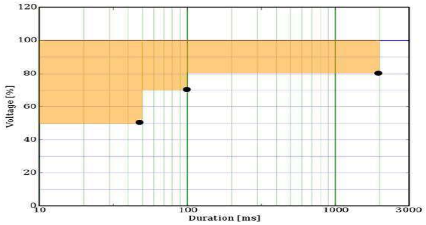
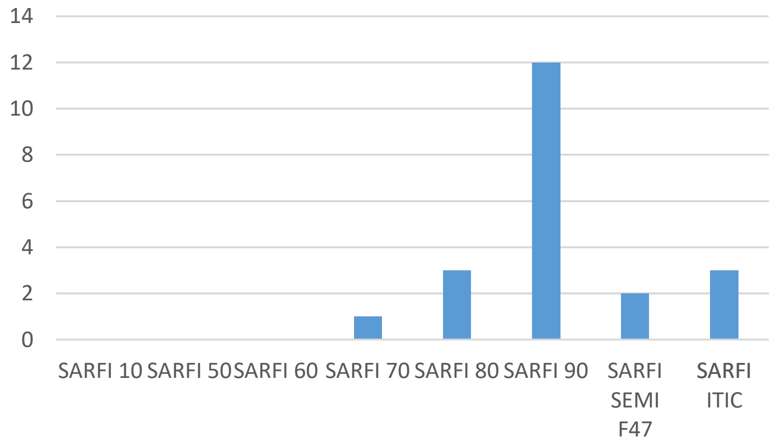


Figure 23—Recommended Type III test levels

SARFI DATA

Import Name	(5/31/2015 - 12/8/2015)	
Event Count	12 total events	
Monitor Years	0.52 years	
Average Sag Magnitude (%)	82.30%	
Average Sag Duration (sec)	0.362s	
Median Sag Magnitude (%)	84.50%	
Median Sag Duration (sec)	0.125s	
	Normalized to 1 Year	Raw Count
SARFI 10	0.0	0
SARFI 50	0.0	0
SARFI 60	0.0	0
SARFI 70	1.9	1
SARFI 80	5.7	3
SARFI 90	22.9	12
SARFI SEMI F47	3.8	2
SARFI ITIC	5.7	3

- This dataset represents only 0.52 years of information
- Takeaways:
  - Data Set Incomplete
  - Average Sag Magnitude 82.3%
  - Average Sag Duration is 0.362 sec
  - Median Sag Magnitude is 84.5%
  - Median Duration is 0.125 sec



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PLANT SIDE ANALYSIS & RECOMMENDATIONS

RESILIENCE – EXTEND THE OPERATING ENVELOPE

"Extending the operating envelope" of equipment means that we have to reduce the area of equipment malfunctions by enabling the equipment to ride through deeper and longer voltage sags.

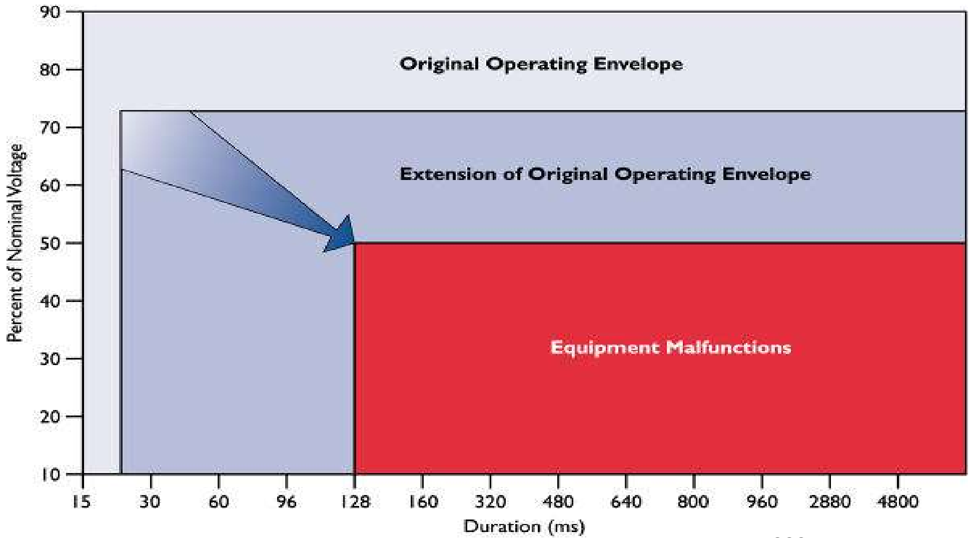

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Table 10—Recommended test points for Type I and Type II voltage sags

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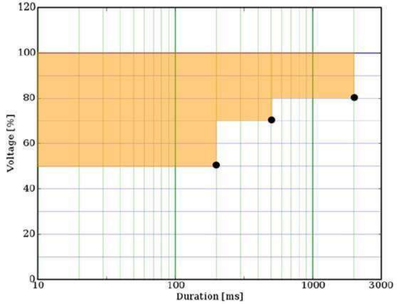

Figure 22—Recommended Type I and Type II test levels

Table 11—Recommended test points for Type III voltage sags

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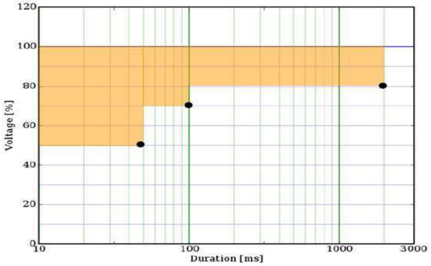
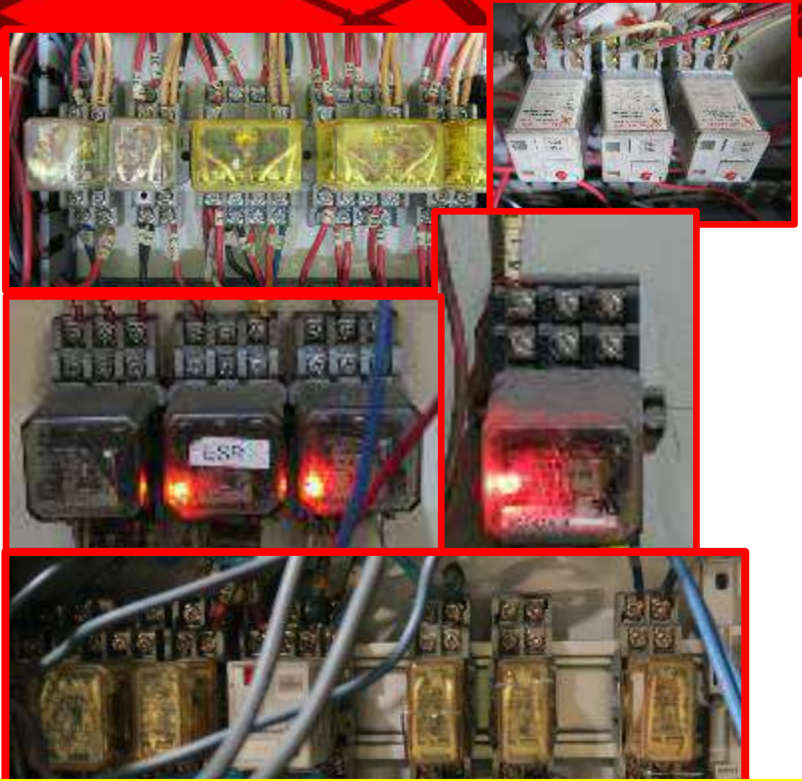


Figure 23—Recommended Type III test levels

KEY FINDINGS FROM [CUSTOMER] ON-SITE AUDIT

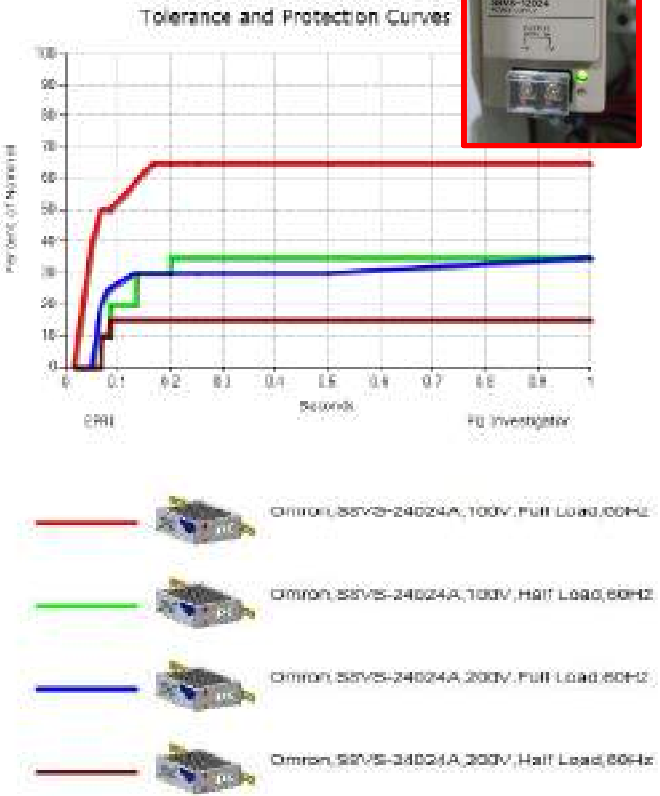
- Most of the process equipment was originally manufactured in the 1990's
  - Equipment has been moved to [customer] from different facilities around the world
  - Equipment has been upgraded on more than one occasion during its 20+ years of service
  - Equipment is largely dependent upon a coordinated drive system.
  - The safety and run permissives of the controls were fed through the contacts of AC Ice Cube relays which are sensitive to voltage sags.
  - The voltage sag ride through of these clear plastic relays is typically 1cycle 72%



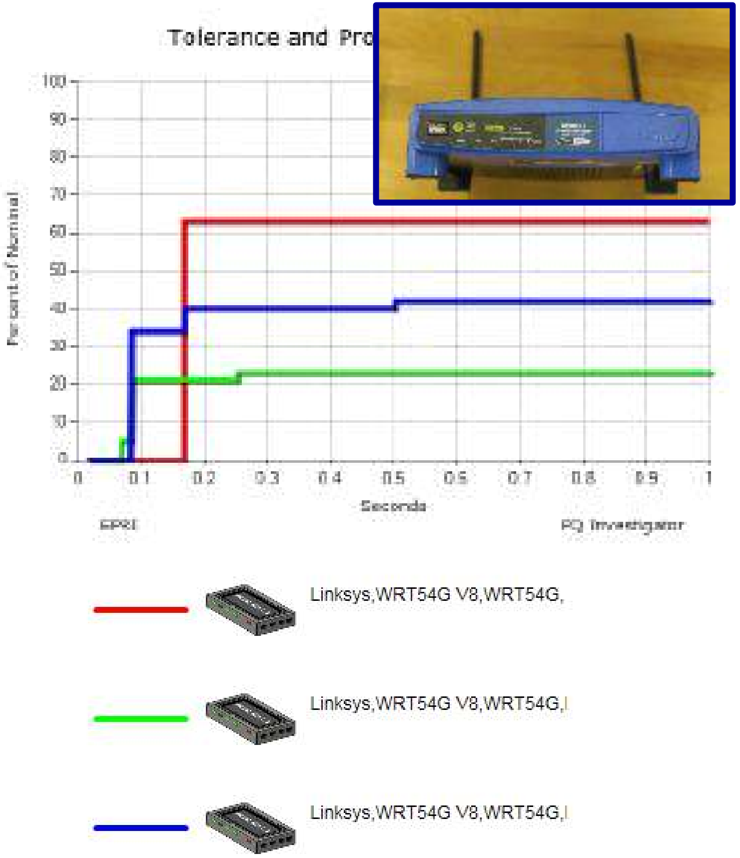
Major Finding: Any voltage sag lower than 72% will cause the relay contacts to open and remove run permissive(s), enable signals, and potentially trigger a false Emergency Power Off (EPO).

KEY FINDING FROM ON-SITE AUDIT (CONT'D)

- Omron S8VS Series DC Power Supply
  - The facility has chosen the Omron power supply for process control throughout the facility
  - EPRI has tested this power supply and found that the voltage sag ride through varies depending upon AC input voltage and the output DC loading
  - If this power supply is powered 100Vac and loaded 100% the voltage sag ride through is 3cycles 65%.
  - Power Supply Nominal Voltage was ~115Vac
  - If power supply is loaded 50% or below the ride through is reduced to 10 cycles 35% nominal
  - If power supply was powered 200Vac or greater the ride through may be better than 15%.
  - DC Load measurements were not taken therefore the ride through of this power supply was assumed at 100% load

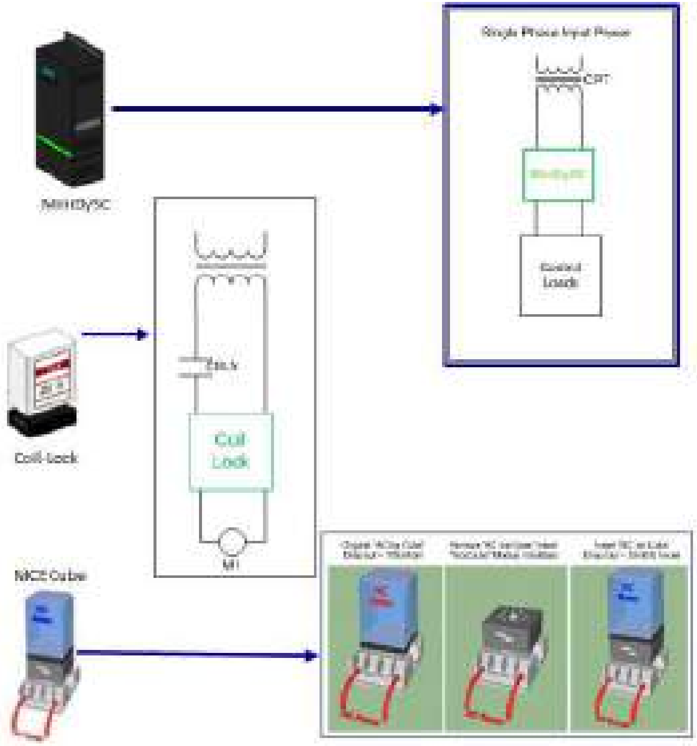


- The equipment has been upgraded on several occasions
- The newest ASDs in the facility communicate through local area network hubs LAN
- These hubs were powered through the service outlets in the cabinets
- May times these service outlets are not powered from the same source as the controls
- Some of these hubs are sourced through outlet style plug in power supplies.
- EPRI tested a router using three different power supplies.
  - The results were drastically different.
  - The power supply with the highest current rating actually produced the worst voltage sag ride through performance.



TYPES OF VOLTAGE SAG
PQ SOLUTIONS

- MiniDySC
  - Static Series Compensator with Capacitor Storage
  - Control Circuit Mitigation
  - 50ms of voltage interruption (more time at reduced load)
- 5 seconds of voltage sag protection to 50% nominal
  - Coil Lock
  - Relay Coil Solution
  - Size based upon coil resistance
  - 3 seconds of voltage sag protection to 25% nominal
- Nice Cube
  - 8 pin octal Ice Cube Relay Solution
  - Direct replacement for 120Vac and 24Vac octal relays
  - 3 seconds of voltage sag protection to 30% nominal



COMPARISON OF VOLTAGE SAG VS. INTERRUPTION SOLUTIONS

Voltage Sag Solutions

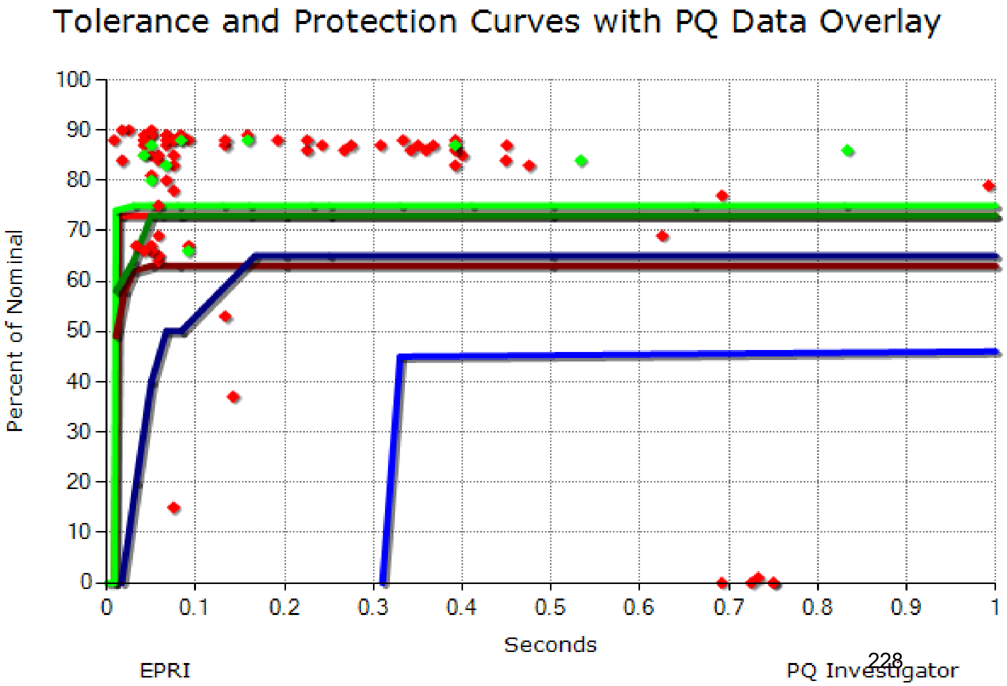
- Pros
  - Lower Cost
  - Less Maintenance
- Cons
  - Less ride through time
  - Protects for voltage sags only
  - Some solutions will protect for a couple cycles of voltage interruption

Interruption Solutions

- Pros
  - Longer ride through time
  - Protection to 0 volts
- Cons
  - Higher cost
  - Ultra Capacitor UPS requires fan maintenance

PQ DATA VS. EQUIPMENT SUSCEPTIBILITY

The majority of the control components that were observed during the audit are included in the graphic below.



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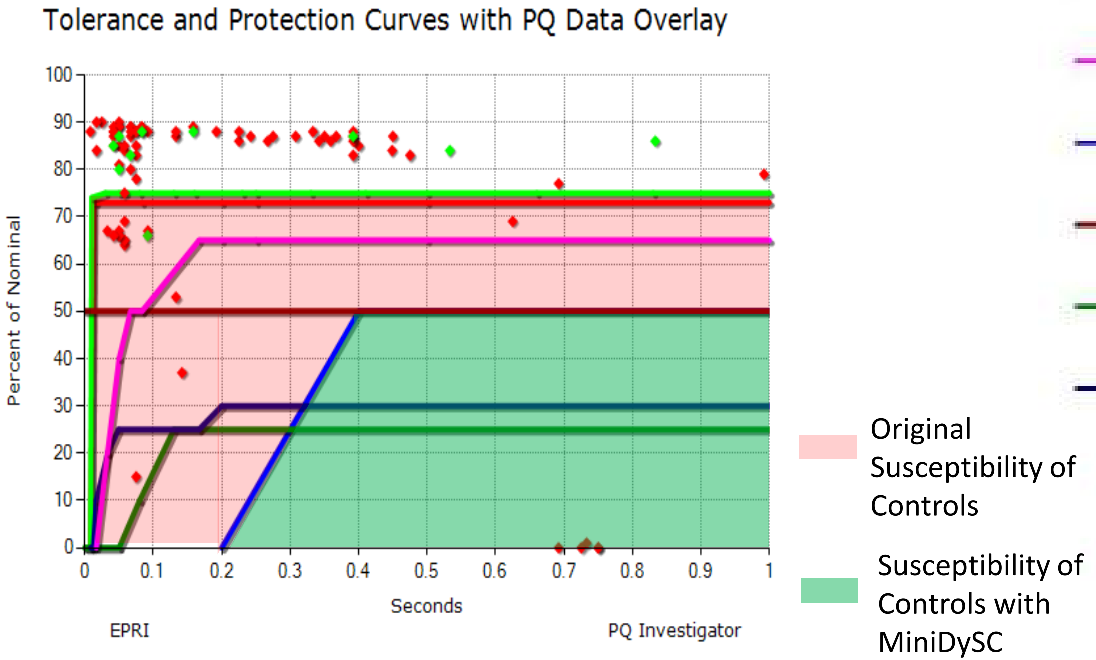
PQ DATA WITH EQUIPMENT SUSCEPTIBILITY AND MITIGATOR

The solutions shown are designed to protect for voltage sags.



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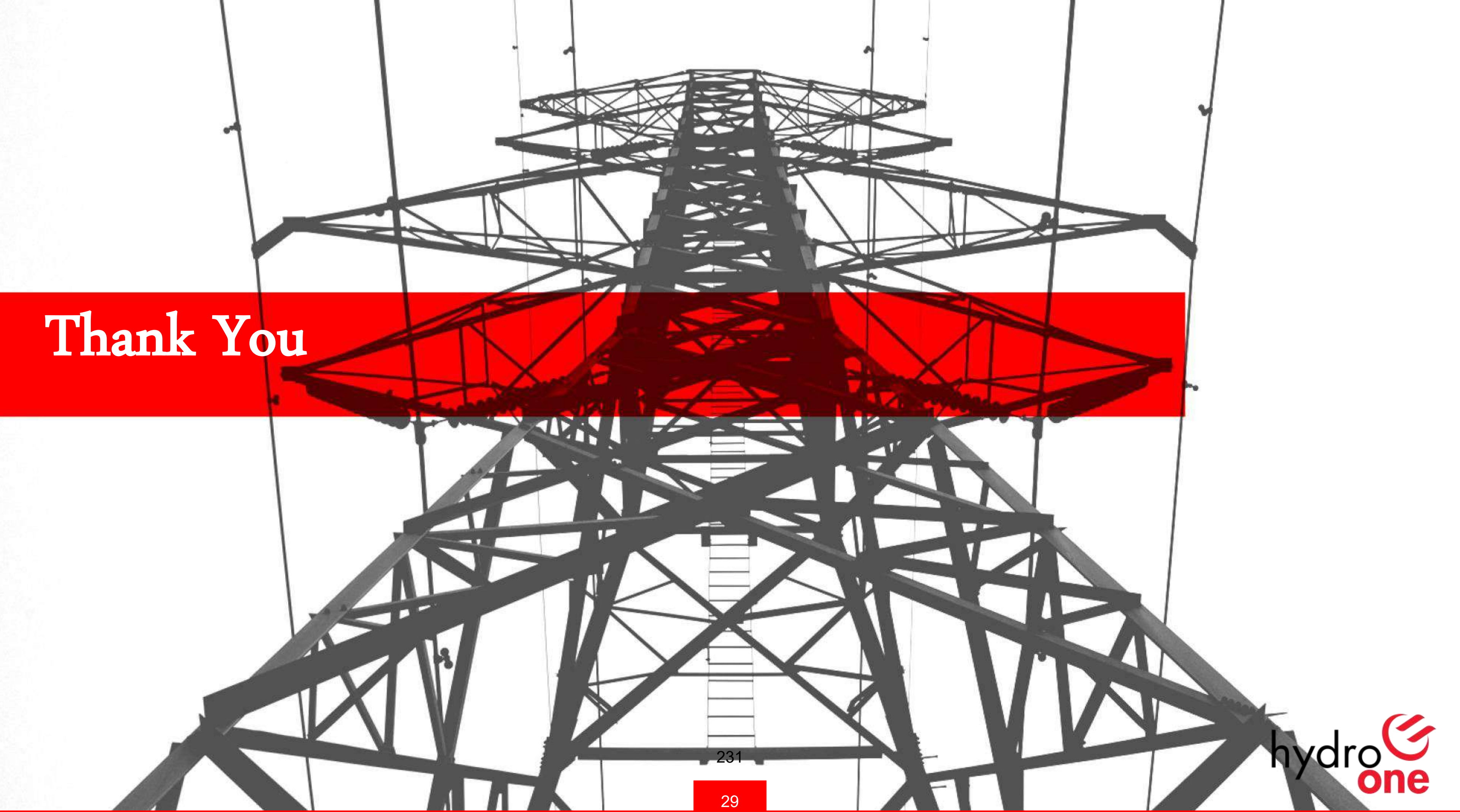
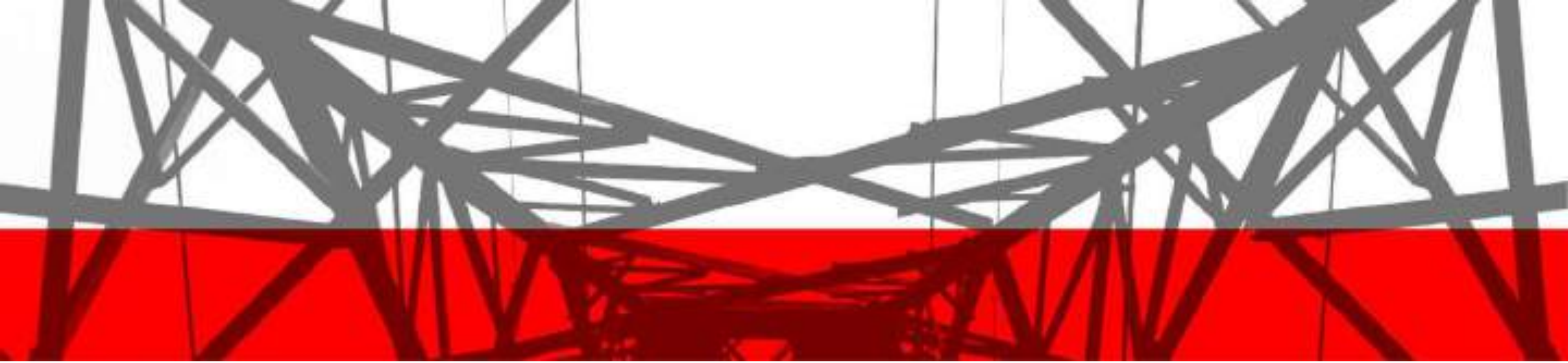
Questions?

Thank You



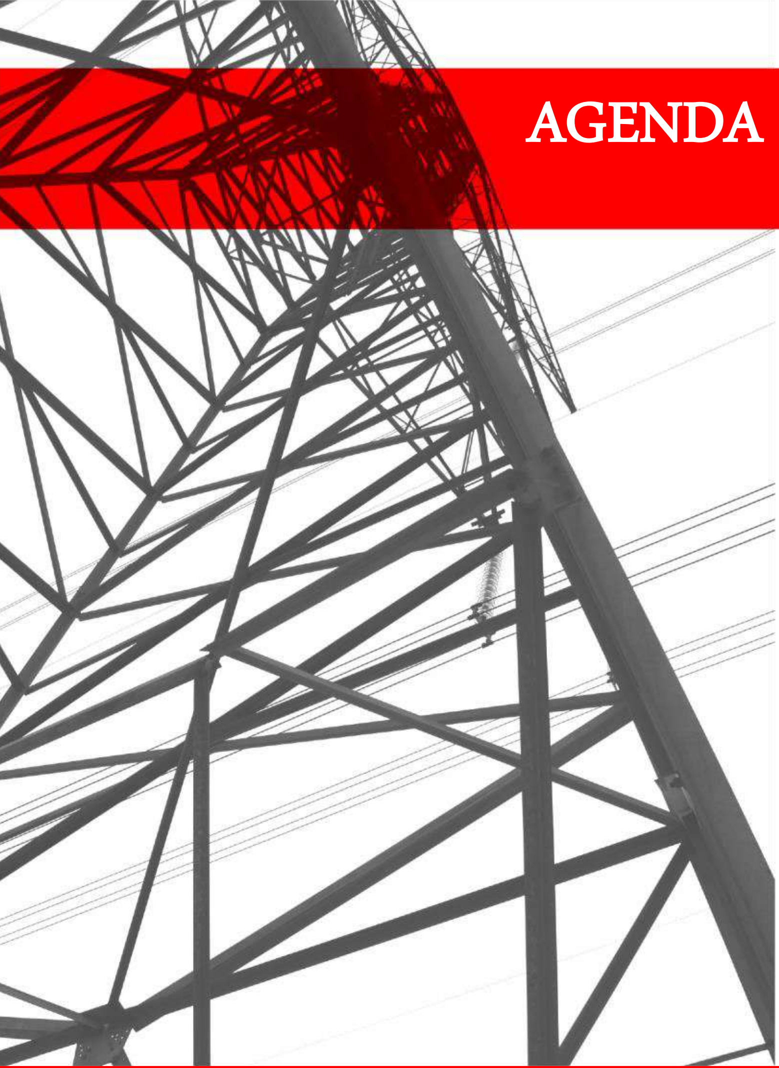
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



VOICE OF THE CUSTOMER

2016 Large Customer Conference



AGENDA

1. Purpose of today's session
2. Our commitment to large customers
3. What we've heard from you
4. What we've done to meet your needs
5. Now, it's your turn
6. It doesn't end today

VOICE OF THE CUSTOMER

Purpose of today's session

- Listen to your concerns and better understand your needs
- Identify any opportunities to add value to your business
- Capture your feedback and ensure follow-up by your Account Executive

VOICE OF THE CUSTOMER

Our commitment to large customers

- Large customers are a major driver of our success
- We are fully committed to continuous improvement

VOICE OF THE CUSTOMER

What we've heard from you last year

- Customer service, response timeliness and communications
- Rates and rate design
- Impacts of new/updated technology
- Power Quality and reliability

VOICE OF THE CUSTOMER

What we've done to meet your needs

- Drive process, reporting and communication improvements to identify and respond to your needs
    - Tx Customer Consultation sessions
    - Reliability Report and Customer Delivery Point Performance Standard

VOICE OF THE CUSTOMER

Now it's your turn

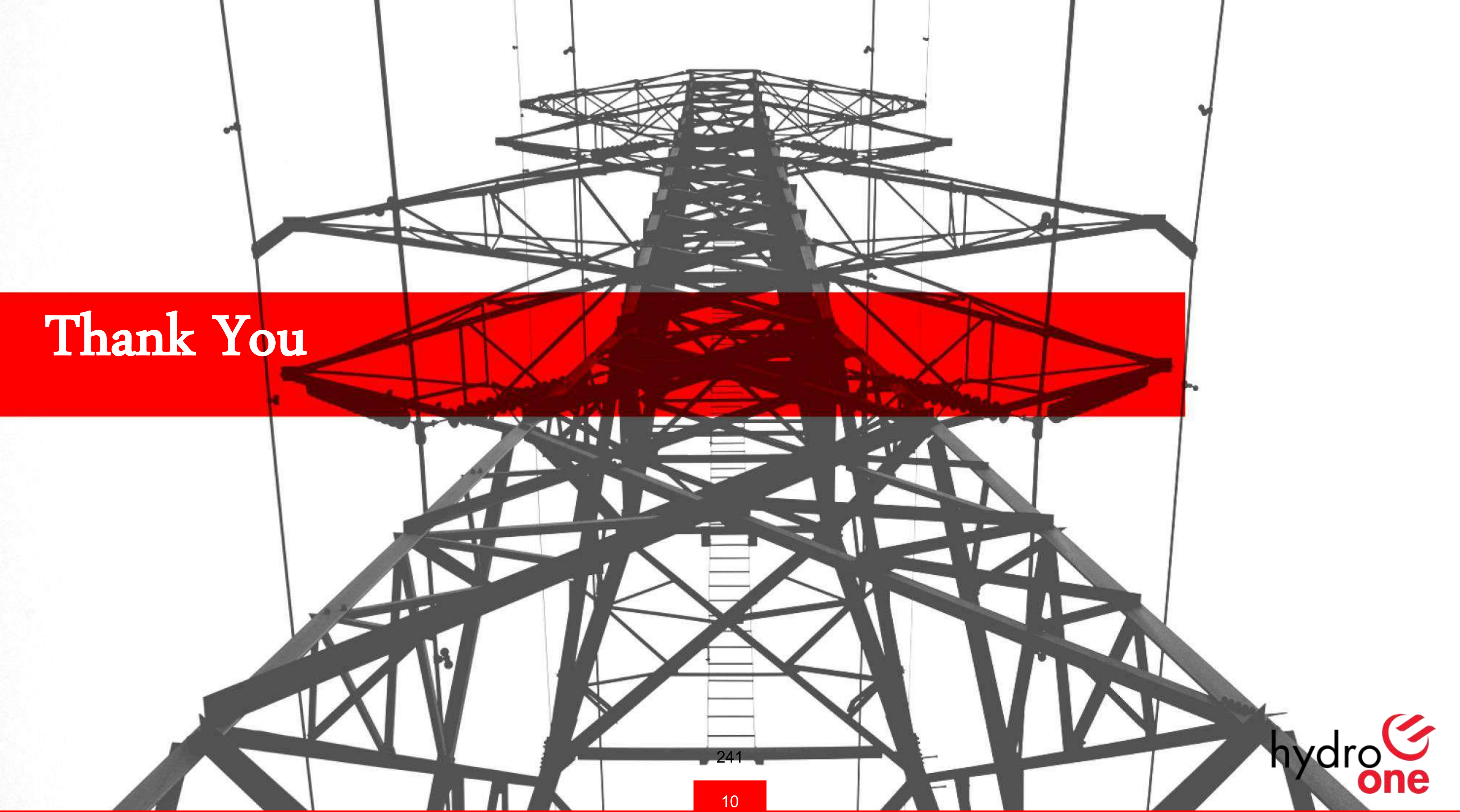
- Raise your hand so we can see you
- Please introduce yourself by stating your name and organization

VOICE OF THE CUSTOMER

It doesn't end today

- Your Account Executive, Executive Sponsor and/or other staff will follow-up with you directly

Thank You



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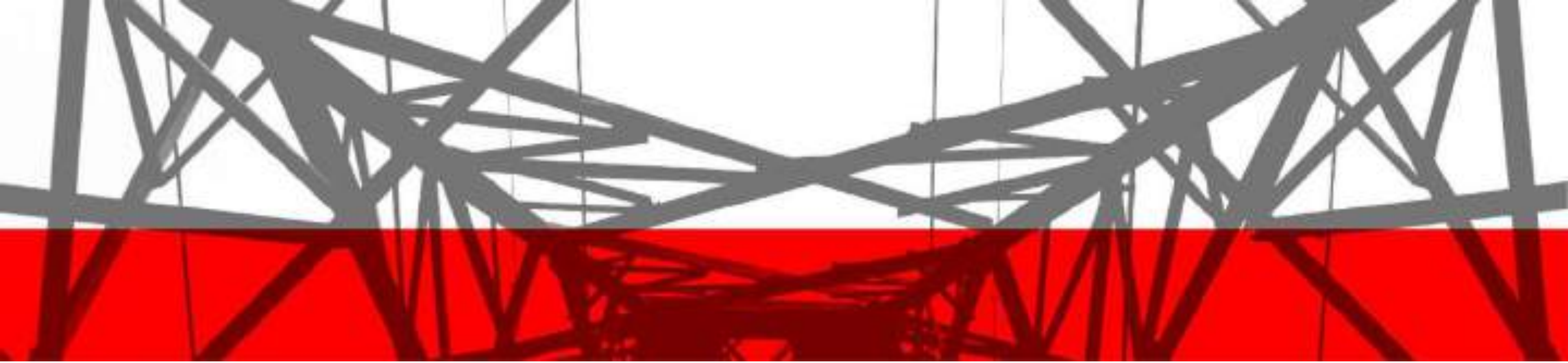
LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



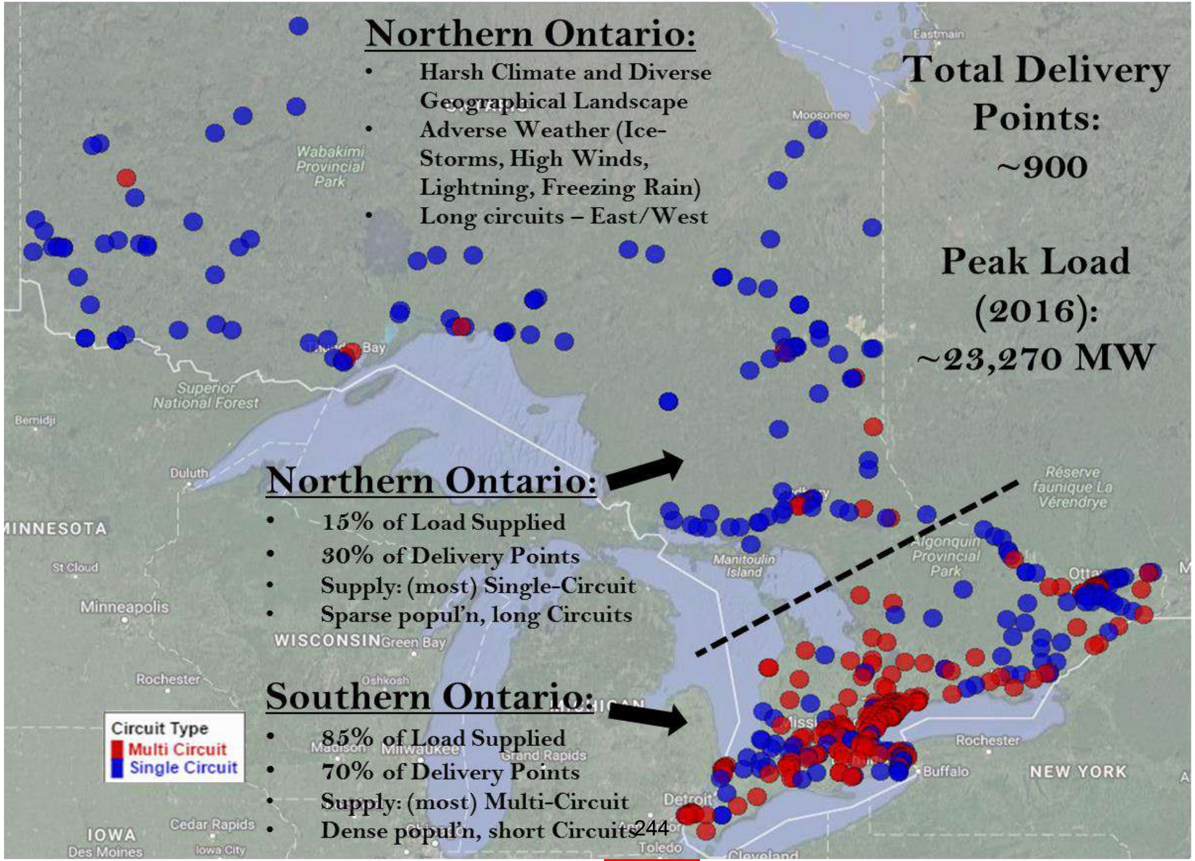
TRANSMISSION RELIABILITY (SAIDI/SAIFI)

Scott McLachlan

Director, Planning Optimization

Hydro One

ONTARIO LANDSCAPE: DELIVERY POINTS
MULTI-CIRCUIT VS SINGLE-CIRCUIT SUPPLIED



Northern Ontario:

- Harsh Climate and Diverse Geographical Landscape
- Adverse Weather (Ice-Storms, High Winds, Lightning, Freezing Rain)
- Long circuits – East/West

Total Delivery Points: ~900

Peak Load (2016): ~23,270 MW

Northern Ontario:

- 15% of Load Supplied
- 30% of Delivery Points
- Supply: (most) Single-Circuit
- Sparse popul'n, long Circuits

Southern Ontario:

- 85% of Load Supplied
- 70% of Delivery Points
- Supply: (most) Multi-Circuit
- Dense popul'n, short Circuits244

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TRANSMISSION CIRCUIT-KM OVERVIEW

Overall System

Supply Nature of Transmission Circuit	Sub-Total circuit-km	% of Total circuit-km	Northern Ontario (km)	% of Total Northern	Southern Ontario (km)	% of Total Southern
Network Assets (NO Customers)	9,695	32.1%	4,735	39.4%	4,960	27.2%
Multi-cct [1]DP Customers	11,993	39.6%	1,257	10.4%	10,736	58.9%
Single-cct [1]DP Customers	6,674	22.1%	5,032	41.8%	1,642	9.0%
Generation Customers (Only)	1,523	5.0%	860	7.1%	663	3.6%
Interconnections	369	1.2%	146	1.2%	223	1.2%
Total Transmission System circuit-km	**30,253**	**100%**	**12,030**	**100%**	**18,224**	**100%**

Industrial End-Users

Supply Nature of Transmission Circuit	Sub-Total circuit-km	% of Total circuit-km	Northern Ontario (km)	% of Total Northern	Southern Ontario (km)	% of Total Southern
Multi Circuit Supply	1,403	**4.6%**	60	**4.3%**	1,343	**95.7%**
Single Circuit Supply	1,802	**4.6%**	1,702	**94.5%**	100	**5.5%**

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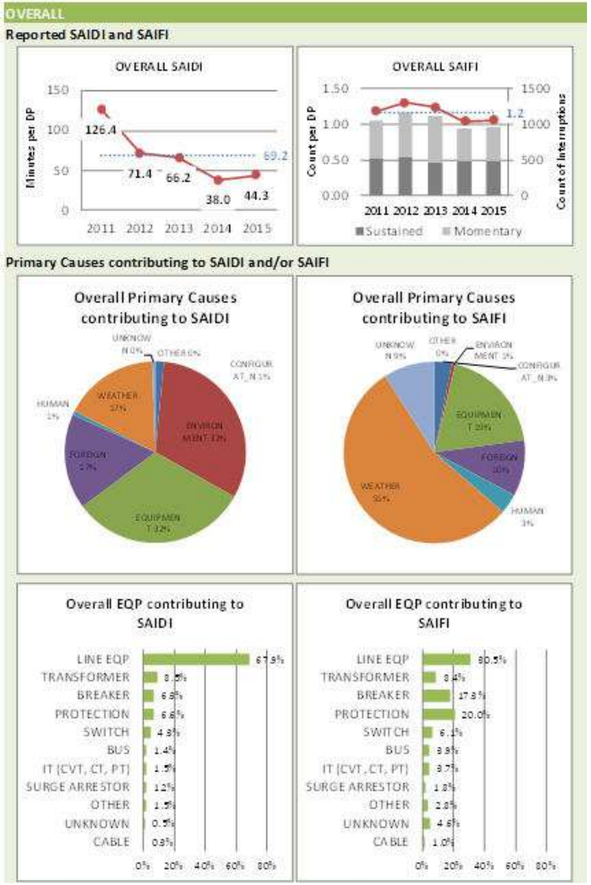
OVERALL TRANSMISSION PERFORMANCE

- **Lightning** is the major contributor to SAIFI (higher frequency, momentary events)
- **Equipment Failure** is the major contributor to SAIDI (low frequency, but longer duration)
- 1st Quartile (CEA benchmarked)
- SAIDI 5-Year Average: ~69.2 minutes
- SAIFI 5-Year Average: ~1.2 interruptions

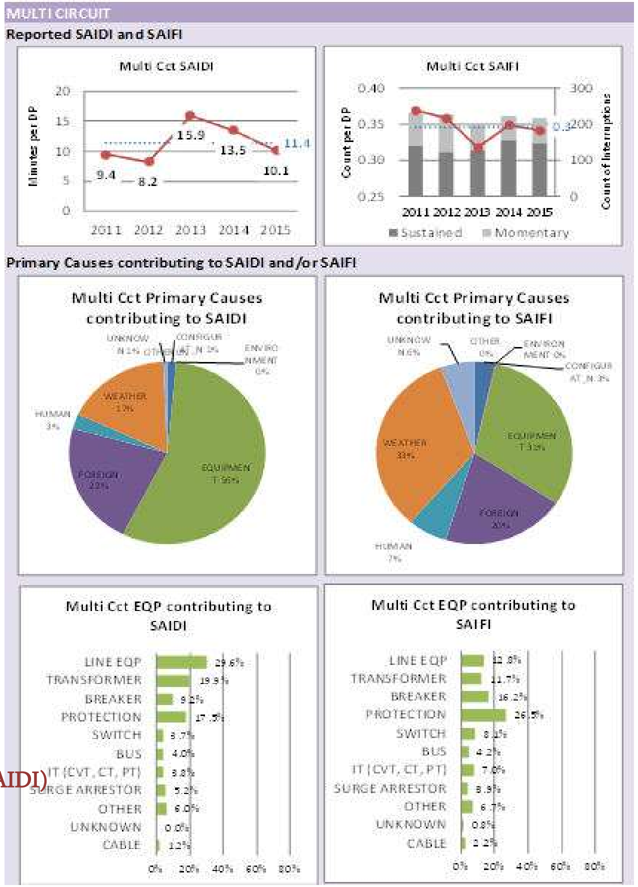


SAIDI/SAIFI → Primary Causes → Eqmt Class

PRIMARY Cause EQP Failure: 42% of total interrupted minutes (SAIDI)

MULTI-CIRCUIT SUB-SYSTEM

- 85 % of total supplied LOAD
- Higher Customer Density, (shorter lines in some cases)
- Contingent Supply (Two)
- Predominant in Southern Ontario and Urban areas
- 1st Quartile (CEA benchmarked)
- SAIDI 5-Year Average: ~11.4 minutes
- SAIFI 5-Year Average: ~0.3 interruptions

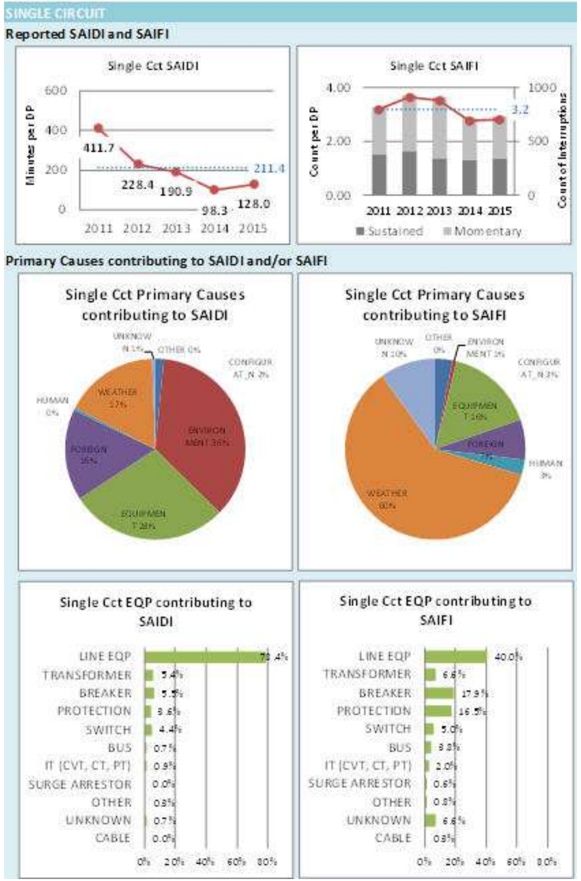


SAIDI/SAIFI → Primary Causes → Eqmt Class

PRIMARY Cause EQP Failure: 50% of total interrupted minutes (SAIDI)

SINGLE-CIRCUIT SUB-SYSTEM

- 15 % of total supplied Load
- Lower Customer Density
- **NO** Contingent Supply
- Predominant in Northern Ontario and Rural areas
- Susceptible to adverse weather
- Lightning contributes to higher frequency, momentary events
- Estimated 2nd Quartile (Not benchmarked)
- SAIDI 5-Year Average: ~211.4 minutes
- SAIFI 5-Year Average: ~3.2 interruptions



SAIDI/SAIFI → Primary Causes → Eqmt Class

PRIMARY Cause EQP Failure: 41% of total interrupted minutes (SAIDI)

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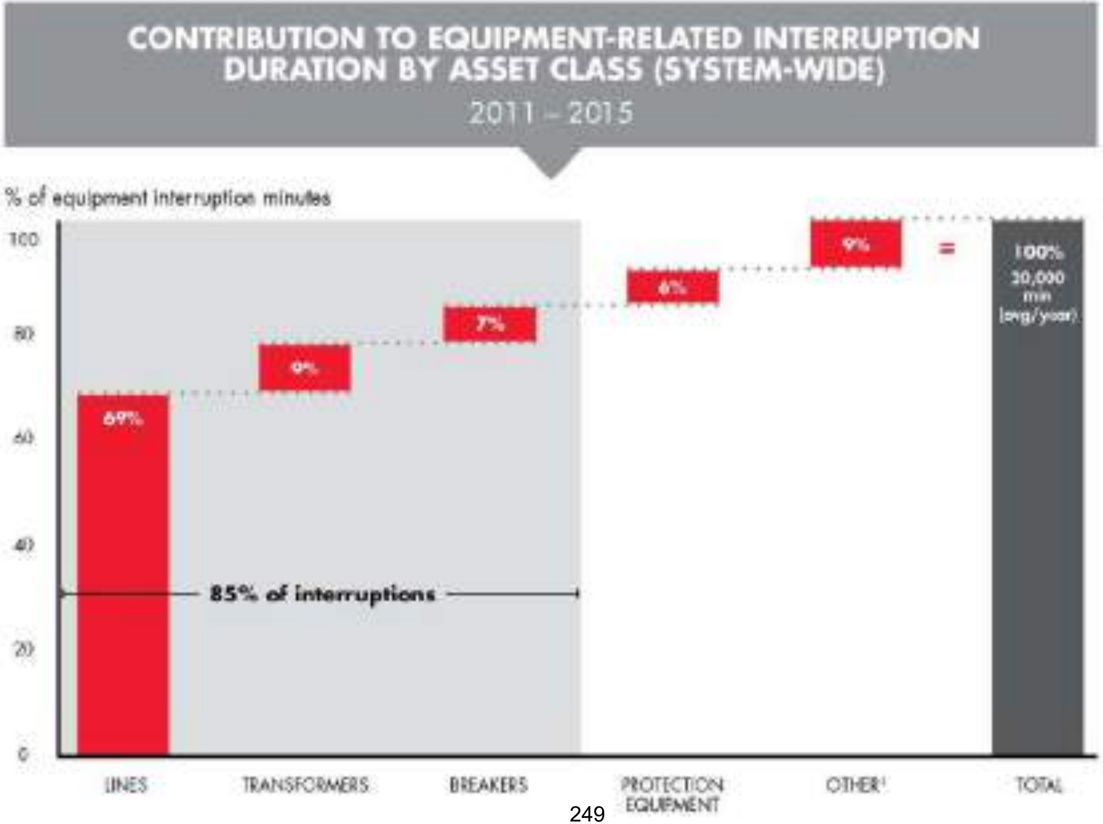
EQUIPMENT FAILURES

MAJOR TYPES CONTRIBUTING TO INTERRUPTION DURATION



TRANSMISSION CUSTOMER CONSULTATION FEEDBACK

Performance Comparison with other Customers Locally

Established 10 Local Reliability Areas:

South	Greater Toronto Area (GTA)
	Metro Toronto
	Hamilton Niagara
	East
	Central
	West
North	South West
	Sudbury-Algoma
	North East

Performance Comparison with Industry Peers

Established 3 Reliability Peer Groups:

- Direct Industrial
- Local Distribution Company (LDC)
- Hydro One Distribution

For Q2-2017, Hydro One has an initiative to launch a NEW web portal for our Customers showing insight into our Transmission Customer Reliability Metrics.

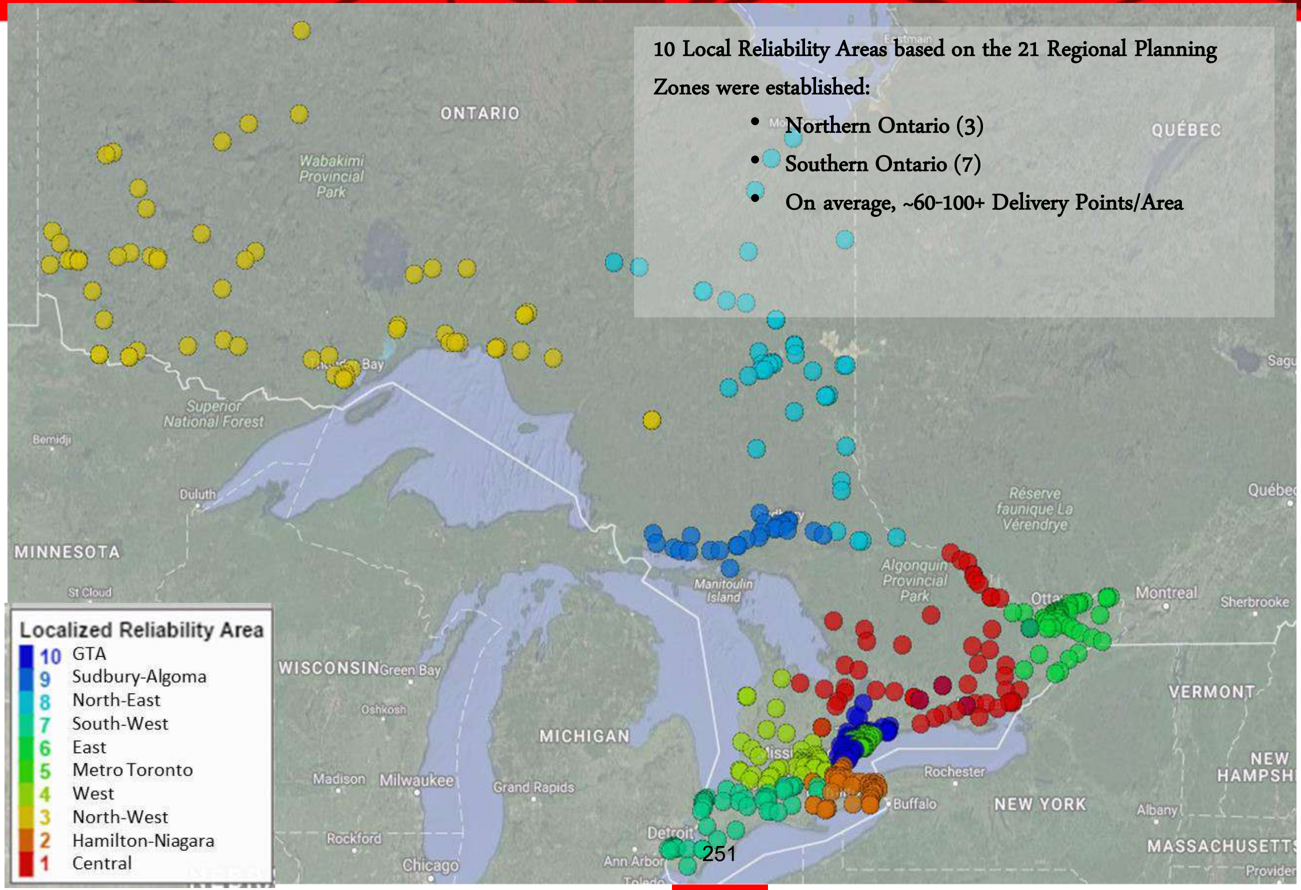
This web portal will allow Customers to:

- **View their Historical and Year to Date Performance for Duration and Frequency**
- **Have transparency into their Performance Reliability, revealing trends and/or isolated events**
- **Compare their performance with Peer Groups and Localized Area**

LOCAL RELIABILITY AREAS

10 Local Reliability Areas based on the 21 Regional Planning Zones were established:

- Northern Ontario (3)
- Southern Ontario (7)
- On average, ~60-100+ Delivery Points/Area



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EXAMPLE: SOUTH-WEST - SAIDI/SAIFI

HISTORIC 5-YEAR 2011-2015

OVERALL | **MULTI CIRCUIT** | **SINGLE CIRCUIT**

EXAMPLE: SOUTH-WEST - SAIDI/SAIFI

MONTHLY YEAR-TO-DATE

OVERALL **MULTI CIRCUIT** **SINGLE CIRCUIT**

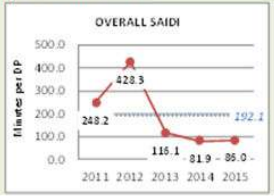
DIRECT INDUSTRIAL, LDC AND H1-DX INDICES

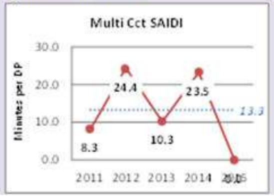
HISTORIC 5-YEAR 2011-2015

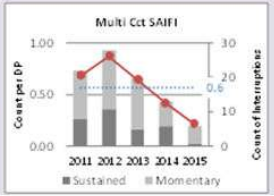
Direct Industrial

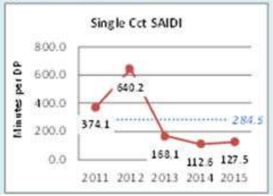
OVERALL | MULTI CIRCUIT | SINGLE CIRCUIT

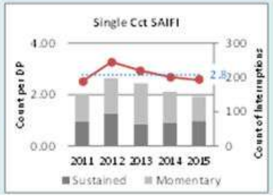
Reported SAIDI and SAIFI







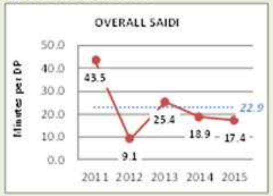


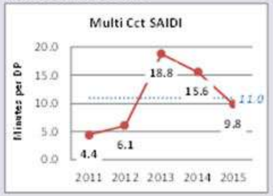


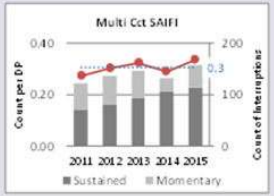
Local Distribution Company

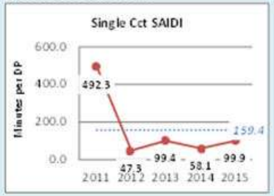
OVERALL | MULTI CIRCUIT | SINGLE CIRCUIT

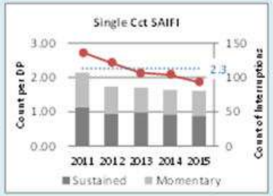
Reported SAIDI and SAIFI









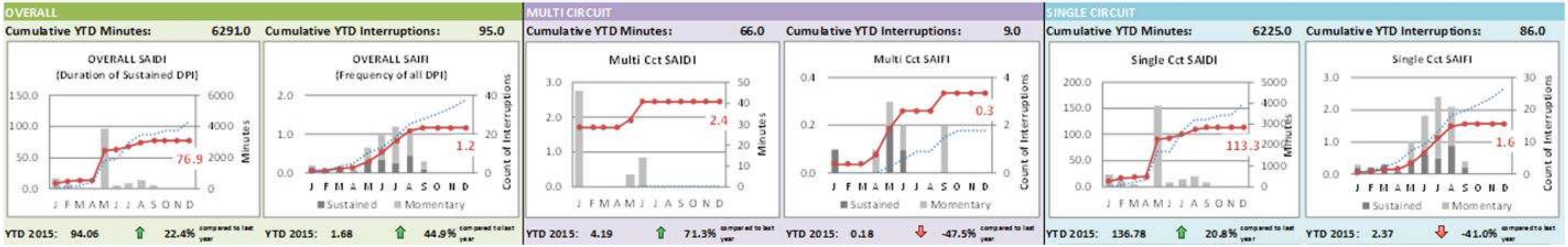


Generators.... FUTURE

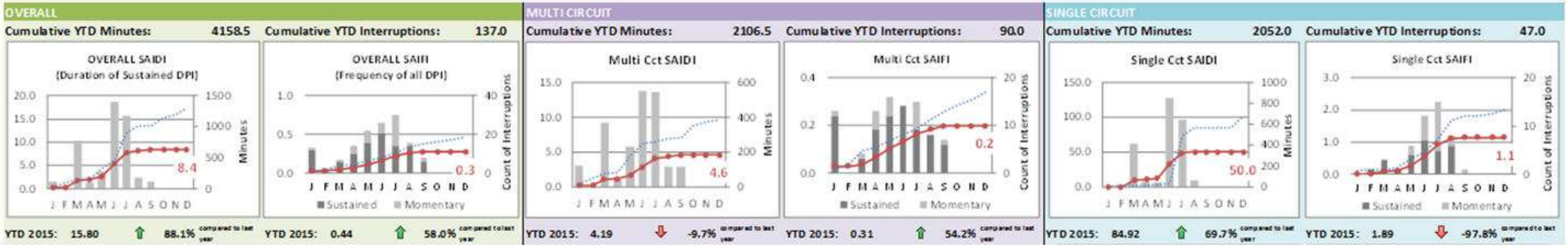
DIRECT INDUSTRIAL, LDC AND H1-DX INDICES

MONTHLY YEAR-TO-DATE

Direct Industrial



Local Distribution Company



Generators.... FUTURE

OVERALL PERFORMANCE
HISTORIC 5-YEAR 2011-2015

OVERALL

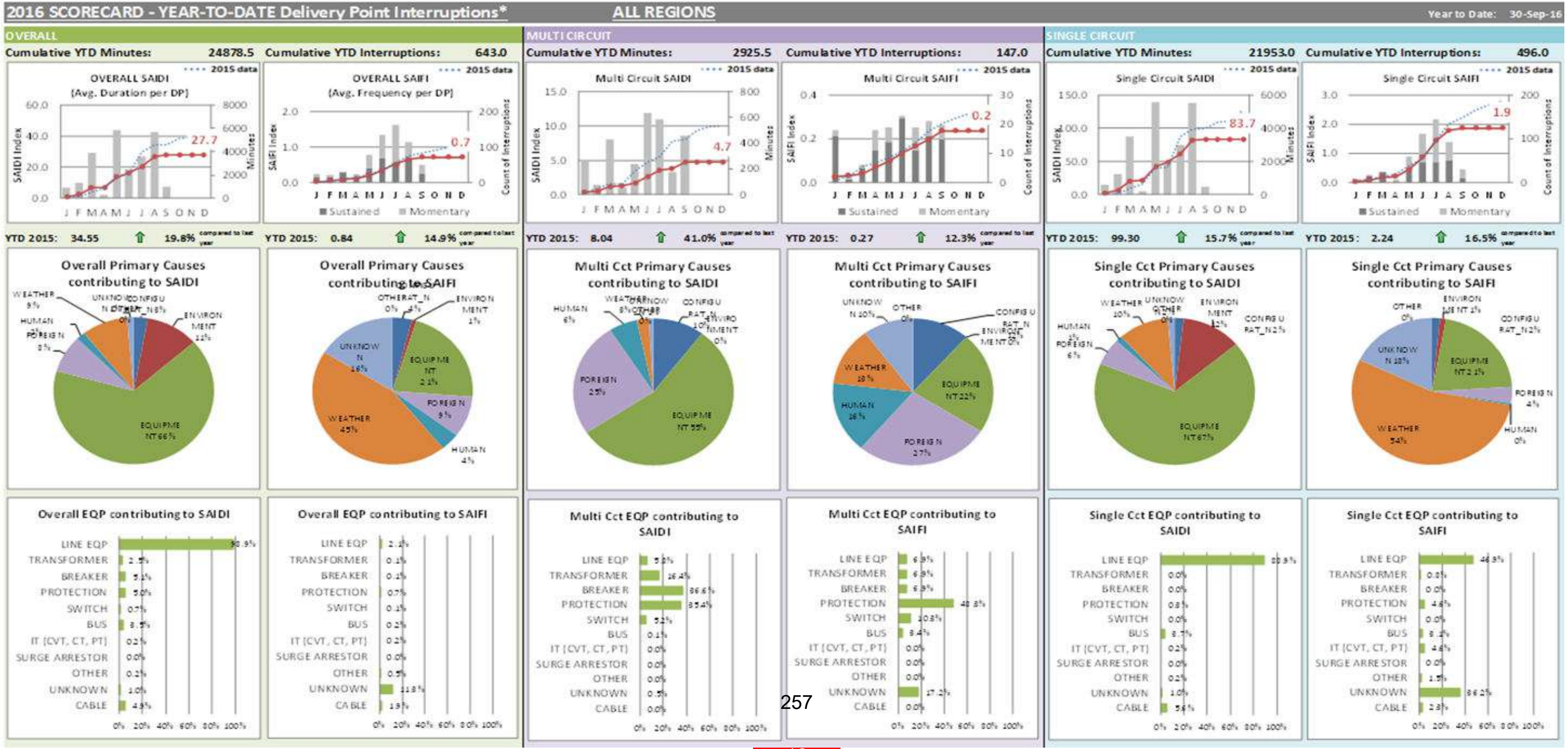
MULTI CIRCUIT

SINGLE CIRCUIT

256

OVERALL PERFORMANCE
MONTHLY YEAR-TO-DATE

OVERALL ## MULTI CIRCUIT ## SINGLE CIRCUIT



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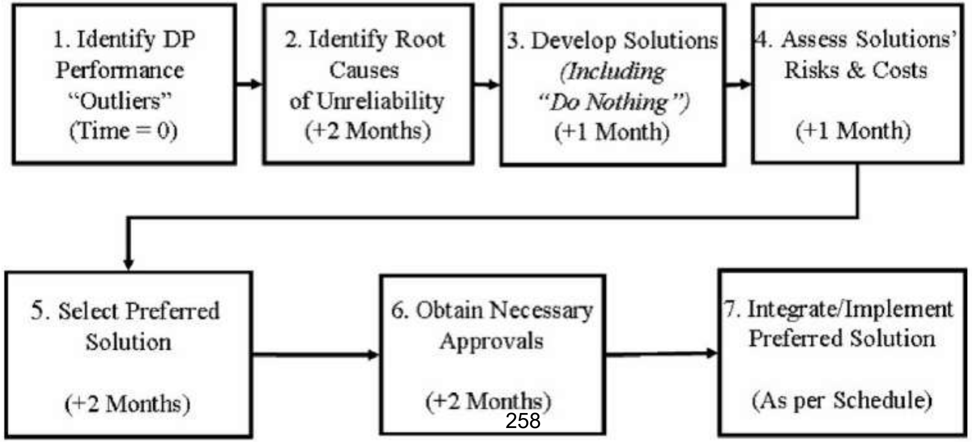
CUSTOMER DELIVERY POINT PERFORMANCE (CDPP) STANDARDS

- The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point (DP) level

- The approved CDPP Standard consists of two components that:

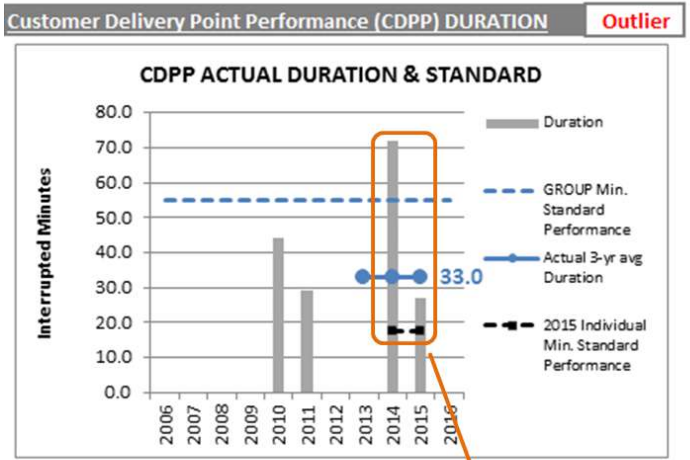
  1. Relate the reliability of supply to the size of load being served at the delivery point (Group Minimum Standard Performance) and
  2. Maintain a customer's individual historical delivery point performance (Individual Minimum Standard Performance)

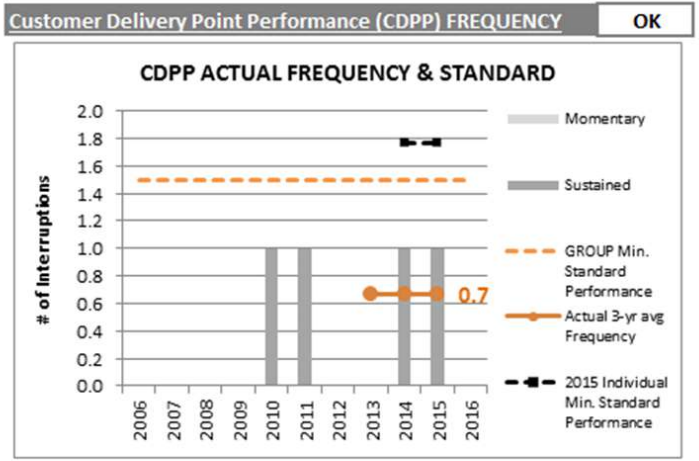


Reference: *EB-2005-0501, Exhibit A, Tab 15, Schedule 3*

CDPP – IDENTIFYING OUTLIERS

Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability





This is a Delivery Point in the GTA.
This DP is an Individual DURATION Outlier because its' Performance has exceeded its' Minimum Standard Performance for 2 consecutive years (2014 & 2015) 259

CDPP – IDENTIFYING OUTLIERS

- When a Delivery Point is identified as an Outlier, it is considered a candidate for remedial action.
- In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability

The CDPP Outlier Appendix A based on the 2014 Outlier Status were issued to customers this year outlining their performance, detailed analysis and any remediation plans.

Appendix A:
Customer Delivery Point Performance (2014 Report) – DP Outlier

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Customer:

Station Name	Delivery Point Designation	LV Bus	Station Avg 3-Yr MW	Supply Circuit
St.Marys TS	NW9Y	Y	16.2	L7S

Performance Standards & Actual Results

Group Standard	Actual Performance (2012-2014 Average)	Minimum Standard Performance	Is this DP an Outlier for this Measure?
Frequency of Interruptions (outages/year)	3.67	3.50	Y
Duration of Interruptions (minutes/year)	34.33	140.00	N

Note: The Group performance standard is based on the 3 year average load being served at the DP

Individual Standard	Actual Performance		Minimum Standard Performance	Is this DP an Outlier for this Measure?
	2013	2014		
Frequency of Interruptions (outages/year)	1	6	19.06	N
Duration of Interruptions (minutes/year)	5	81	124.54	N

Note: The individual performance standard is based on the DP's historical performance. A DP is an outlier when the actual performance exceeds the individual minimumstandard of performance for two consecutive years.

Performance Analysis & Proposed Remediation Plans

Latest CDPP Report Analysis (2014 to 2012, Historic Results)	Post-CDPP Report Analysis (2015 to Mid-2016)
> Majority of Frequency resulted from momentary lightning events. This circuit is a long East-West circuit and is very susceptible to adverse weather historically and continuing. > These events increased 3-yr avg frequency to become a frequency group outlier, marginally. > Single equipment failure due to skywire in 2014 (65 min.) contributed to Duration.	2015: Equipment failure during adverse weather (~500 minutes) and a vehicle contact with structure (~1500 minutes) continue to deteriorate performance. Frequency improved substantially, returning to within historic levels. 2016: Only one interruption to date, minimal duration and weather cause.

Remediation Plans and/or Investments Proposed for this specific DP/Supply Circuit

> Performance indicates a natural return to within acceptable levels for frequency.
> Fault recorders have been acquired and installed to improve the ability to track location of faults. This data is being analyzed by Hydro One to assess possible location of circuit switchers.
> Line operating performance will be assessed through the Regional Planning process which will include circuits L7S, D10H and 61M18, additionally L7S is being assessed for lightnin [illegible] rmance.
> Some insulator and wood pole replacements are planned on [illegible] it in the 2017-2020 business plan
> Monitor performance in next CDPPS report

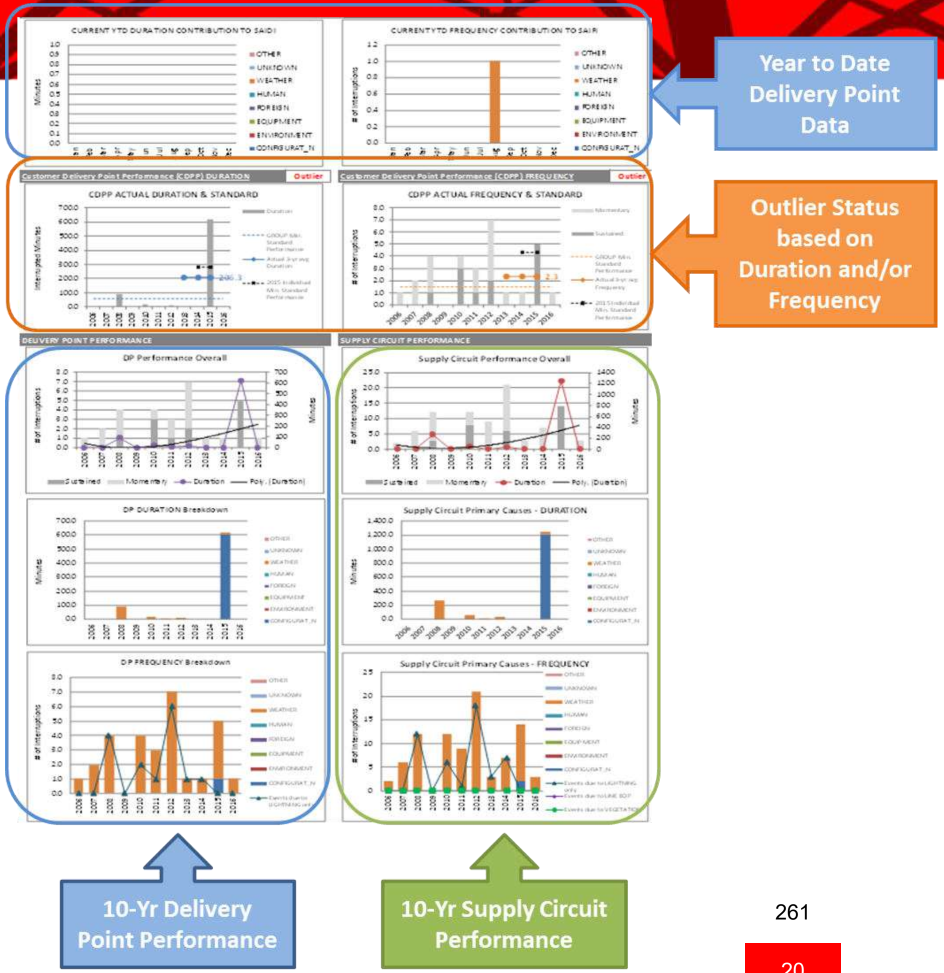
Delivery Point (DP) Data

DP Performance as per GROUP Standard

DP Performance as per INDIVIDUAL Standard

DP Performance Analysis

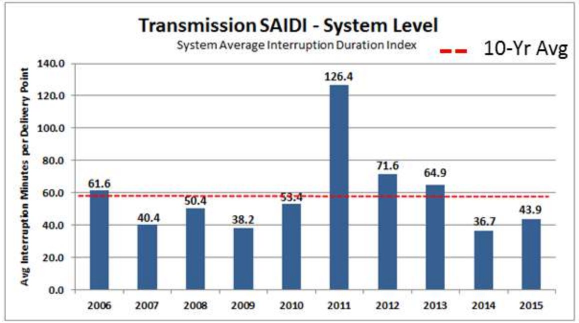
Remediation Plans and/or Investments Proposed

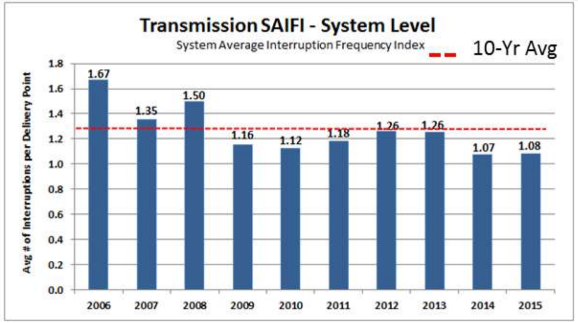


- A Delivery Point and Supply Circuit tool was developed to provide improved analysis, and transparency for both Hydro One and our Customers
- Our goal is to make this available to Customers via web portal log-in
- This tool will provide insight into the general health of the Delivery Point and Supply Circuit
- This report includes Monthly YTD data and 10-Year Performance History, revealing trends and/or isolated events contributing to performance

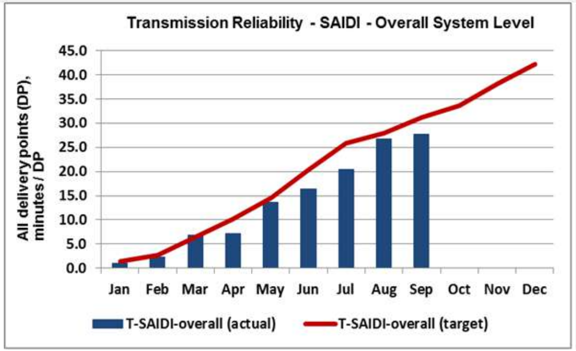
OVERALL TRANSMISSION RELIABILITY

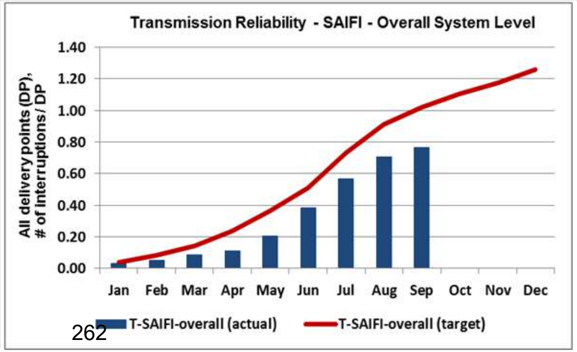
Historic 2006-2015 SAIDI/SAIFI





Year to Date SAIDI/SAIFI





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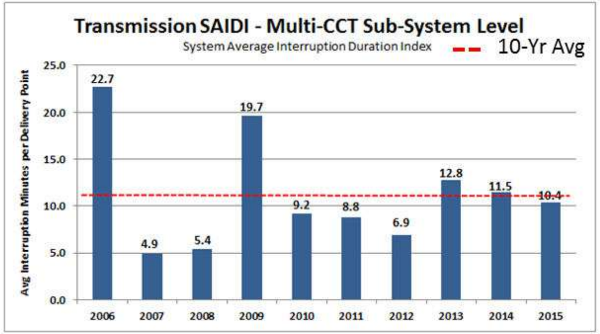
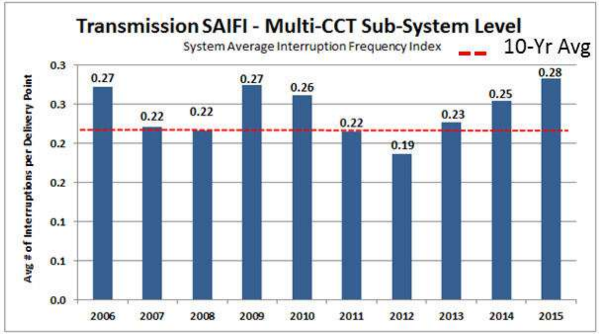
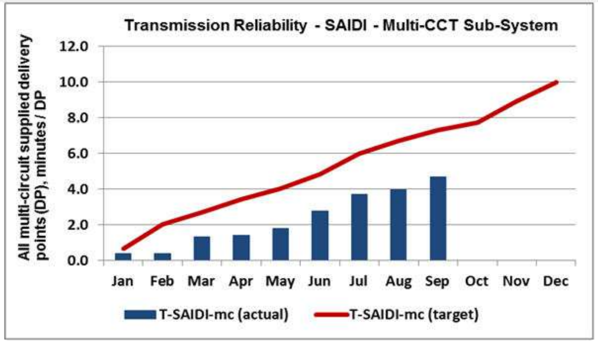
MULTI CIRCUIT RELIABILITY

Historic 2006-2015 SAIDI/SAIFI





Year to Date SAIDI/SAIFI



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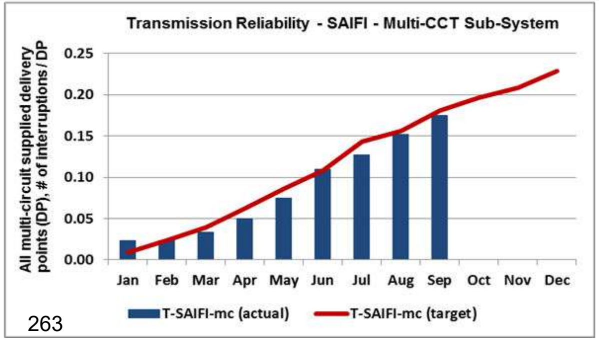

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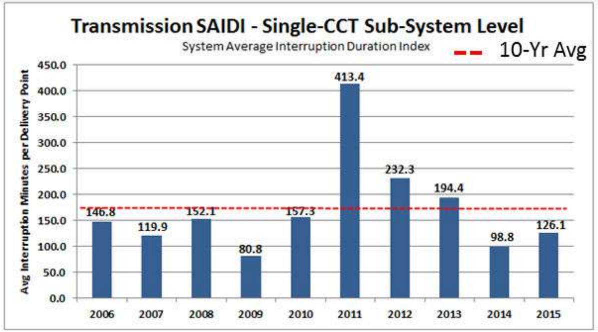
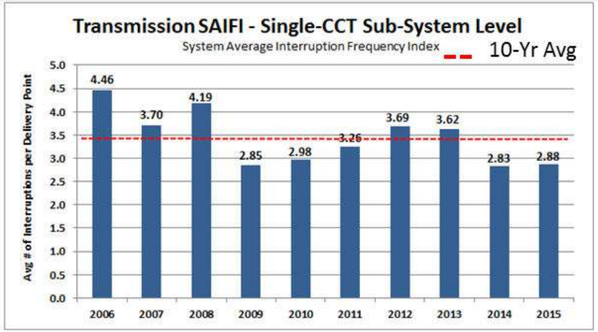
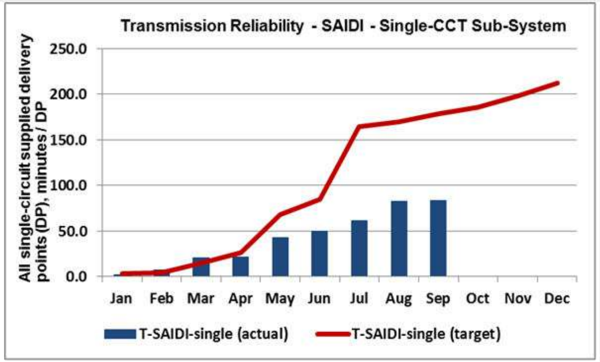
SINGLE CIRCUIT RELIABILITY

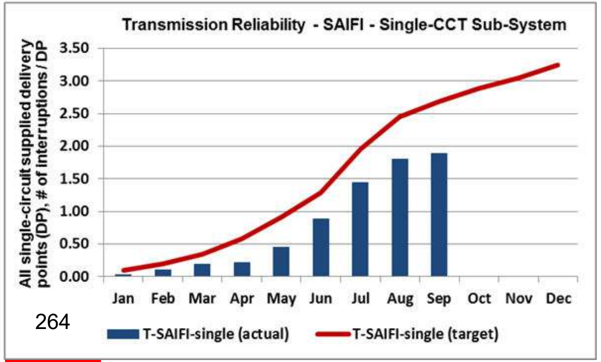
Historic 2006-2015 SAIDI/SAIFI





Year to Date SAIDI/SAIFI





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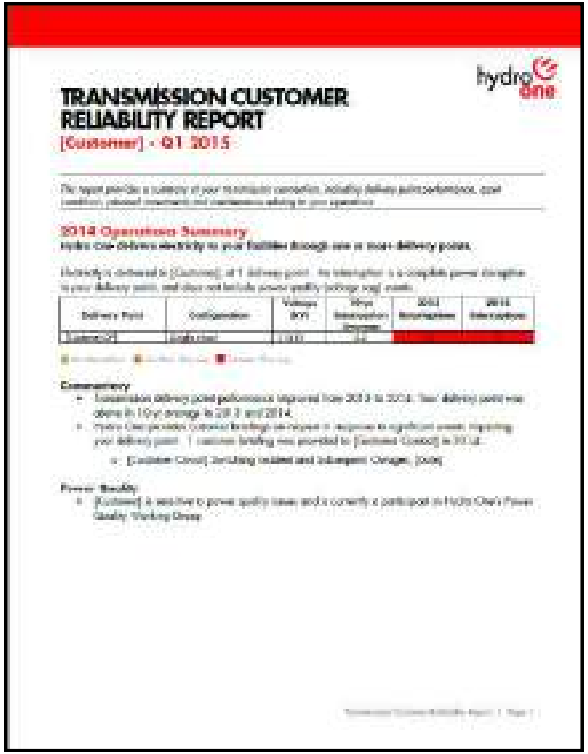
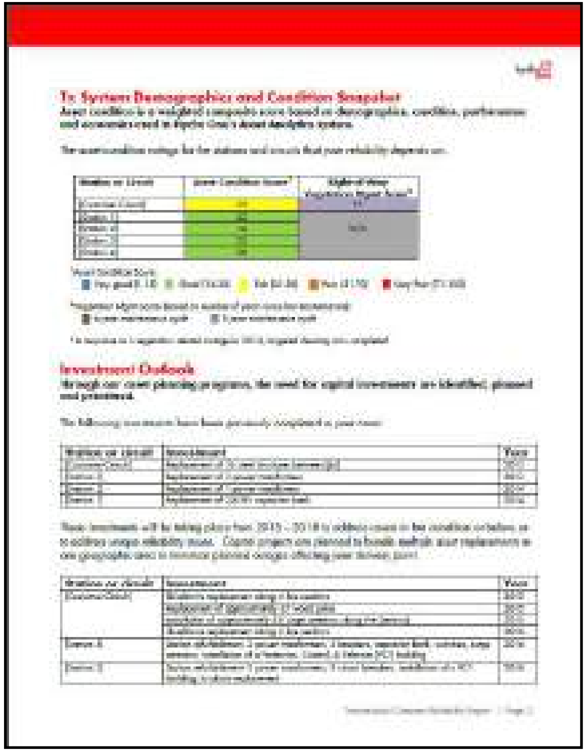
TRANSMISSION CUSTOMER RELIABILITY REPORT


TRANSMISSION CUSTOMER RELIABILITY REPORT
[Customer] - Q1 2015

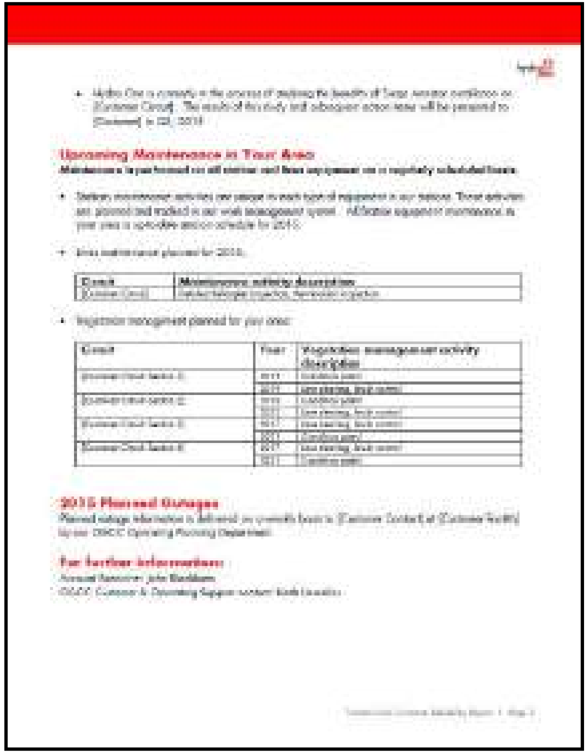
2014 Operations Summary

Commentary

Power Quality


Tx System Demographics and Condition Snapshot

Investment Outlook


Upcoming Maintenance in Your Area

2015 Planned Outages

For further information:

TX RELIABILITY ACTIVITIES/INITIATIVES IN-FLIGHT

- **Enhanced Reporting:**
  - Indices for End-Users, LDCs, Generators
  - 10 Geographical Reliability Areas
  - Tracking YTD – Overall, Multi-CCT, Single-CCT, Primary Causes (i.e. Eqmt)
  - Adverse Weather – Circuit/DP levels

- **Reliability Historical Analysis**
  - Historical Maintenance Spend vs Reliability Contributions
  - Identification of EQMT Failures vs Reliability Impact
- **Customer Delivery Point Performance (CDPP) Standard:**
  - Analysis, Remediation Proposals, Communications to Customer with Outlier DPs

- **Transmission Customer Reliability Reports**

- **Web Portal** (Customers Access via web interface)

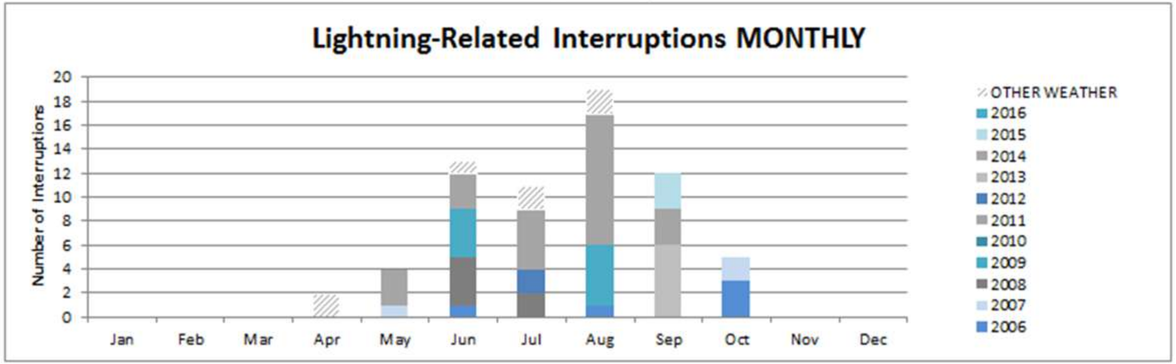
EXAMPLE: WORK-IN-PROGRESS

ADVERSE WEATHER - HISTORIC TREND (LIGHTNING)

ADVERSE WEATHER AND LIGHTNING ASSESSMENT FOR SUPPLY CIRCUIT

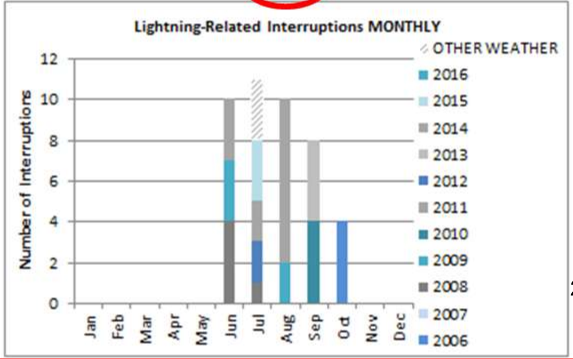
SUPPLY CIRCUIT: B5G | Both Multi and Single Cct | West

HISTORICAL LIGHTNING-RELATED INTERRUPTIONS TO SUPPLY CIRCUIT (MONTHLY)

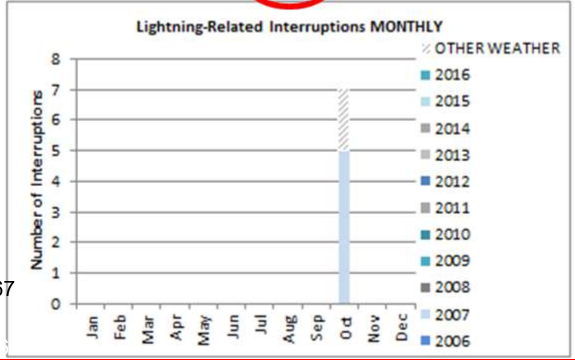


HISTORICAL LIGHTNING-RELATED INTERRUPTIONS TO ALTERNATE SUPPLIES

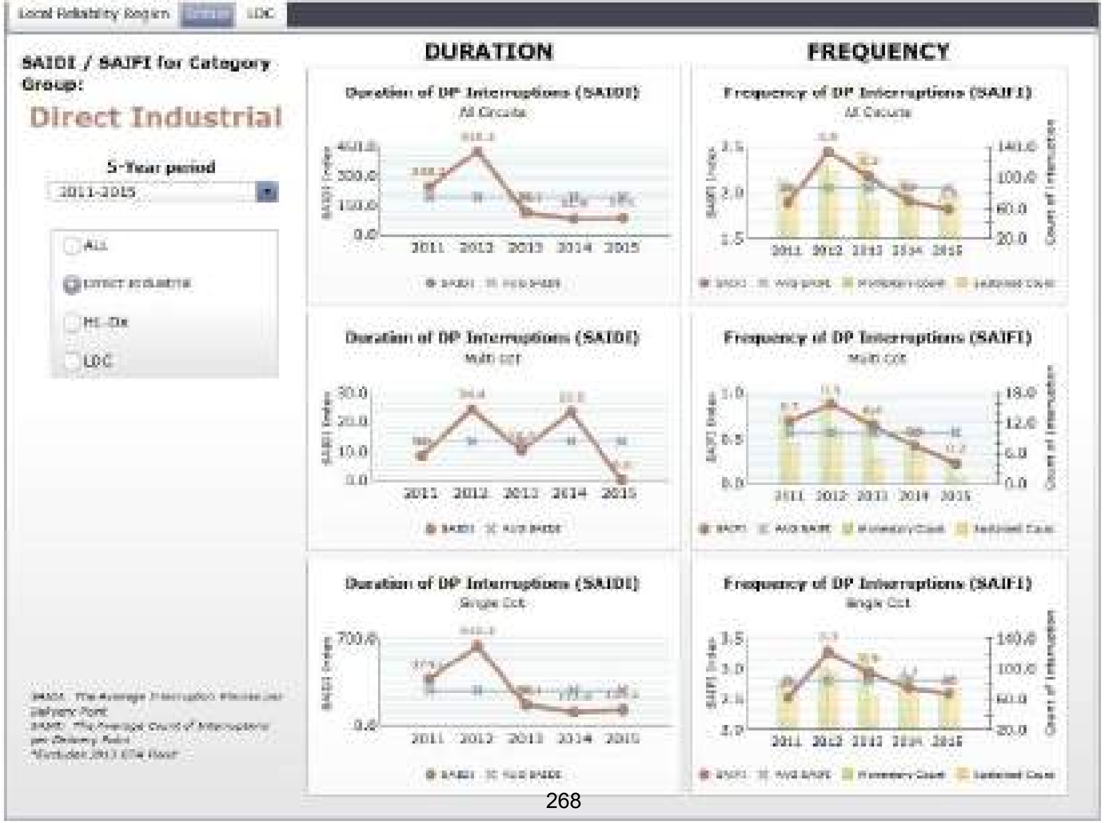
B6G



D7G



EXAMPLE: WORK-IN-PROGRESS / WEB-VIEW



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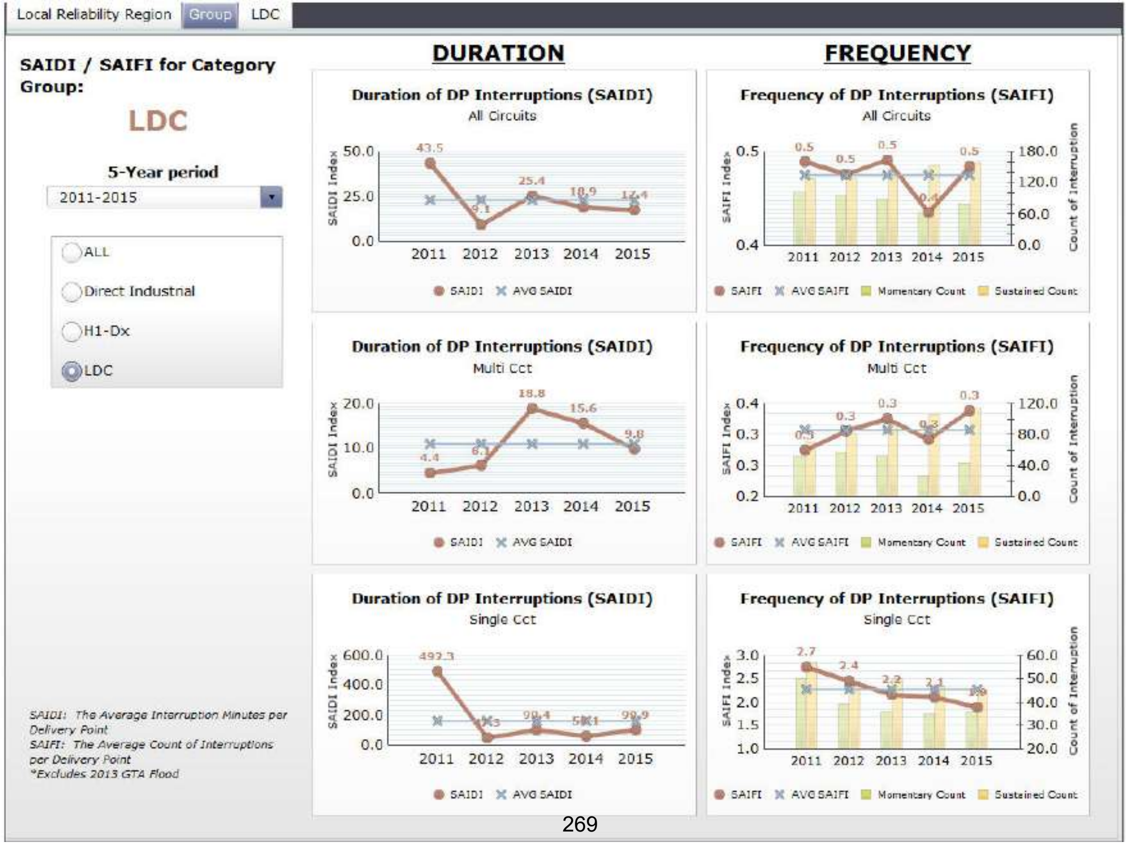
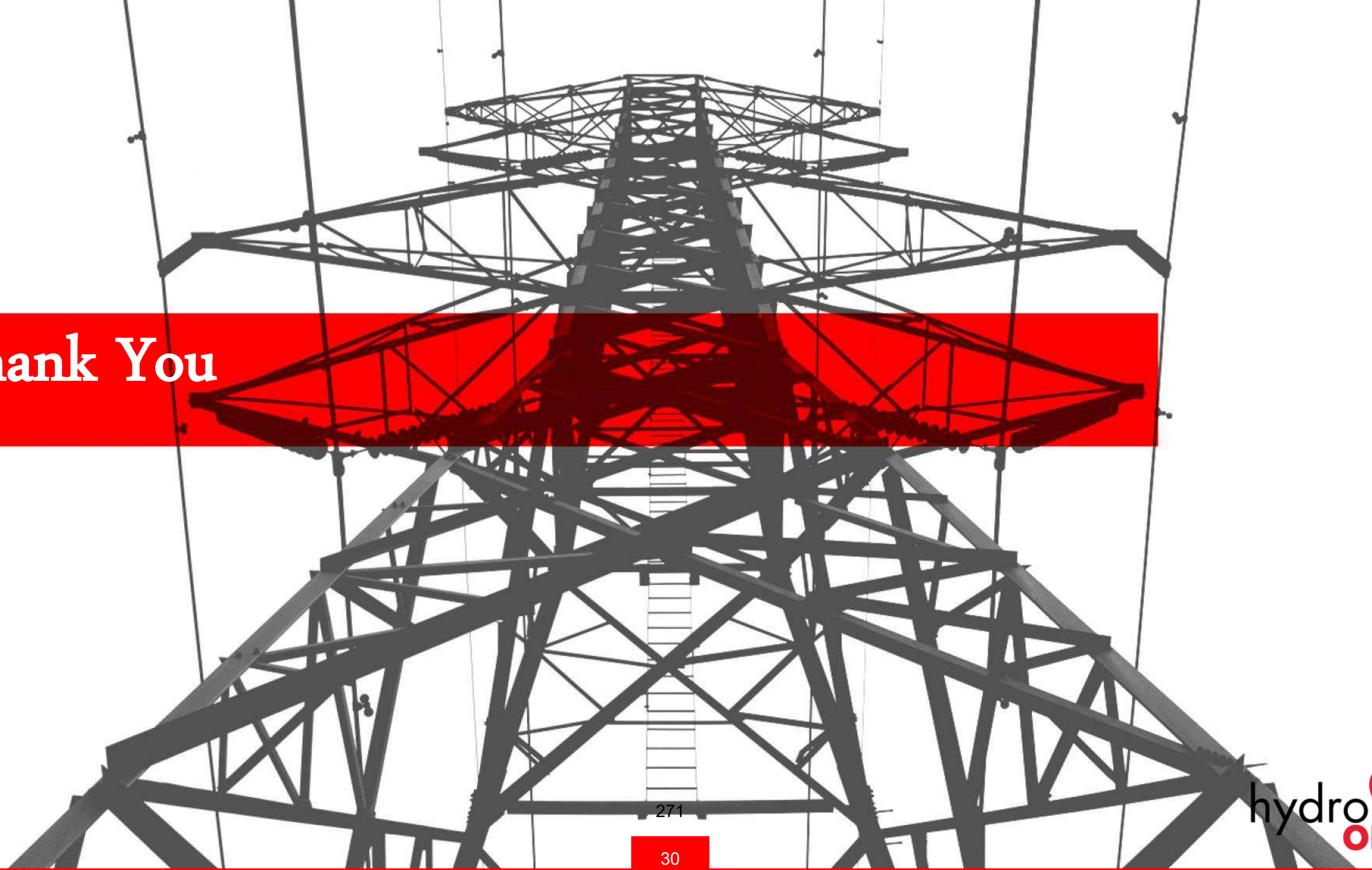
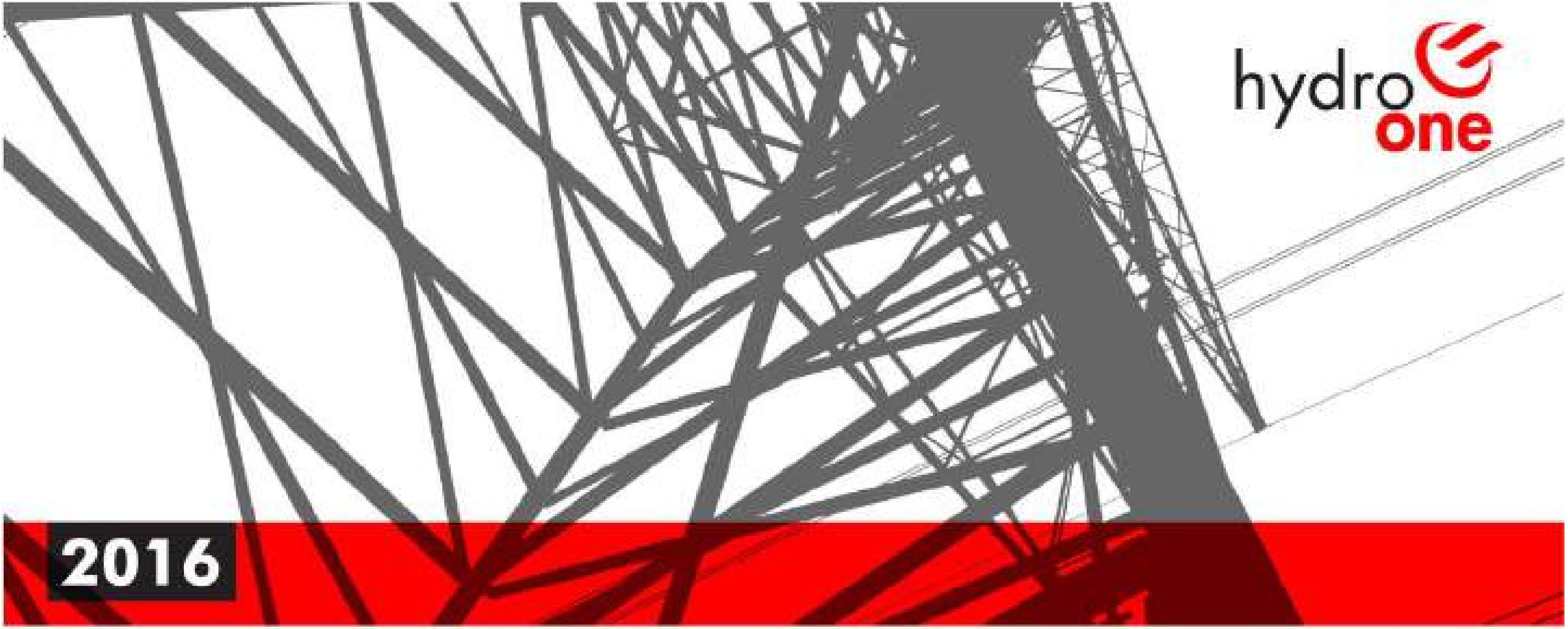
EXAMPLE: WORK-IN-PROGRESS / WEB-VIEW



Questions?

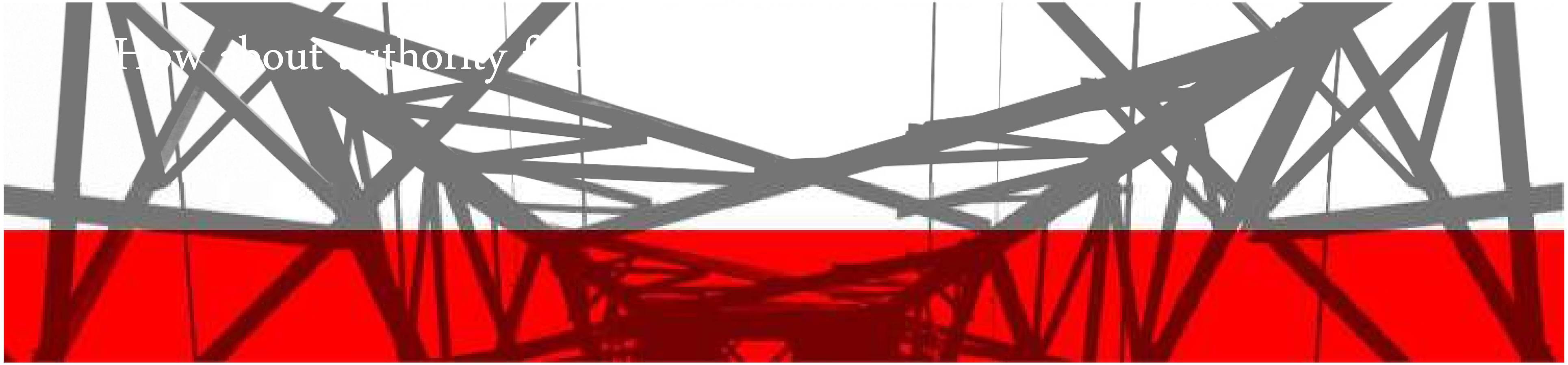
Thank You





LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



CONNECTION & COST RECOVERY AGREEMENT (CCRA)

INITIAL ECONOMIC EVALUATIONS & TRUE UPS

Wade Frost MBA, CPA, CMA

Manager, Decision Support

Hydro One

CCRA OVERVIEW

- Goal is to hold the Tx rate pools harmless when new connections or customer specific upgrades are built
- OEB Transmission System Code (TSC) governs the entire process (section 6.5 and Appendix B)
- Further details in OEB approved Transmission Connection Procedures
- An economic evaluation determines whether a customer capital contribution is required

CCRA OVERVIEW (CONT'D)

- Evaluation of new or modified load connections impact on each rate pool
  - Each evaluation is considered separate from other rate pools (No cross subsidization)

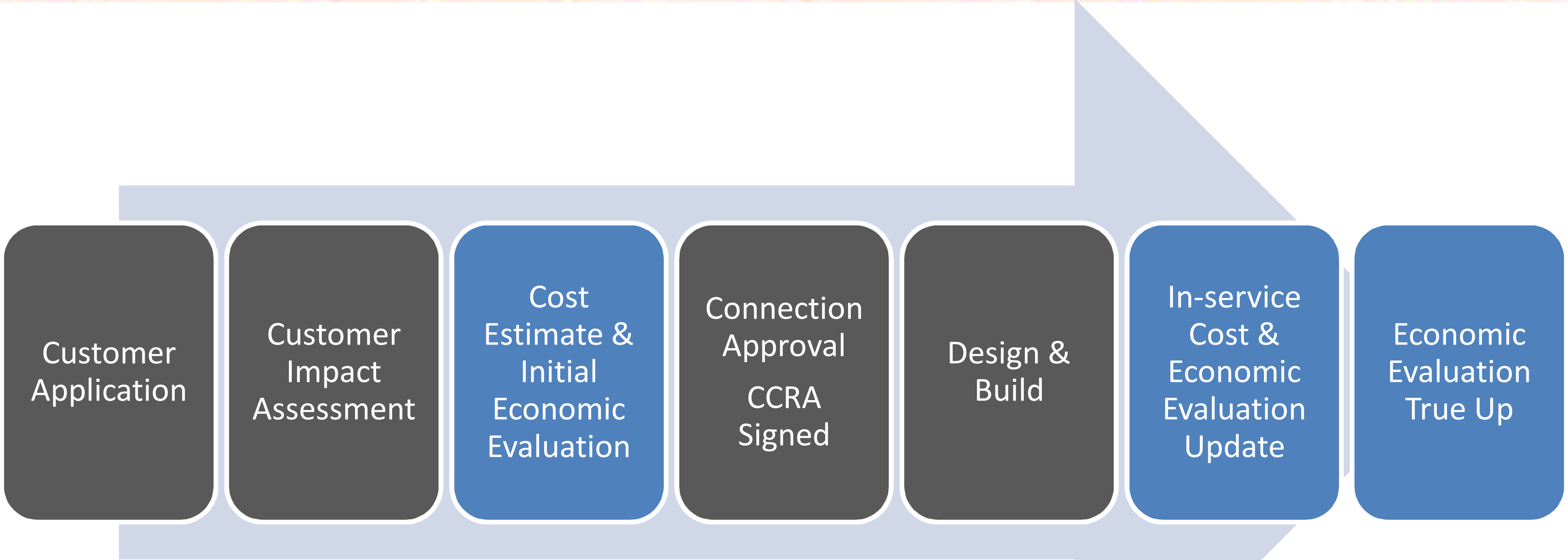
- Up to 25 year forecast of incremental load based on customer risk profile (as per TSC requirements)

- Primary forecast inputs
  - Up-front project costs
  - Incremental load
  - Ongoing operating expenditures

ECONOMIC EVALUATION (CONT'D)

- Economic evaluation based on a discounted cash flow (DCF) model
- A Net Present Value (NPV) result less than zero is considered to cause harm to the rate pool
- A negative impact on the rate pool triggers a capital contribution

PLACE IN CONNECTION PROCESS



- Customer Cost Recovery occurs at predetermined points in the Customer Connection Process

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Initial Economic Evaluation (IEE)

- Initial Economic Evaluation (IEE) prepared based on estimated connection costs and customer load forecast

- CCRA captures IEE results and establishes capital contribution progress payment schedule

- All inputs except actual construction cost and load frozen after IEE completed

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IEE RESULTS!

Date:	1-May-14
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - Actual cost

Facility Name:	Example for Presentation
Description:	Expansion to DESN
Customer:	A Distributor

			In-Service Date	<------ Project year ended - annualized from In-Service Date -------->											
		Month	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1
		Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
								1st true-up					*2nd true-up*		
			0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
Revenue & Expense Forecast															
Load Forecast (MW)			60.0	65.0	70.0	75.0	80.0	85.0	86.7	88.4	90.2	92.0	93.8	95.7	97.6
Load adjustments (MW)			0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				60.0	65.0	70.0	75.0	80.0	85.0	86.7	88.4	90.2	92.0	93.8	95.7
Tariff Applied ($/kW/Month)				2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k				1,454.4	1,575.6	1,696.8	1,818.0	1,939.2	2,060.4	2,101.6	2,143.6	2,186.5	2,230.2	2,274.8	2,320.3
Removal Costs - $k			0.0												
On-going OM&A Costs - $k			0.0	(329.0)	(329.0)	(329.0)	(329.0)	(329.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)	(658.0)
Ontario Capital Tax and Municipal Tax - $K				(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)
Net Revenue/(Costs) before taxes - $k			0.0	1,062.6	1,183.8	1,305.0	1,426.2	1,547.4	1,339.6	1,380.8	1,422.9	1,465.7	1,509.5	1,554.1	1,599.6
Income Taxes - $k			0.0	(122.6)	(8.4)	(65.0)	(119.6)	(172.3)	(136.3)	(164.7)	(192.0)	(218.1)	(243.3)	(267.7)	(291.3)
Operating Cash Flow (after taxes) - $k			0.0	940.0	1,175.4	1,240.1	1,306.7	1,375.1	1,203.3	1,216.1	1,230.9	1,247.6	1,266.1	1,286.4	1,308.3
		Cumulative PV @ 5.78%													
PV Operating Cash Flow (after taxes) - $k	(A)	17,222.9	**0.0**	**914.0**	**1,080.4**	**1,077.6**	**1,073.4**	**1,067.9**	**883.5**	**844.1**	**807.7**	**773.9**	**742.5**	**713.2**	**685.7**
Capital Expenditures - $k															
Capital cost before overheads & AFUDC - $k			(15,000.0)												
- Overheads - $k			0.0												
- AFUDC - $k			0.0												
Total upfront capital expenditures - $k			**(15,000.0)**												
On-going capital expenditures - $k				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k			0.0												
Total capital expenditures - $k			**(15,000.0)**												
Capital Contributions - $k															
Previous capital contribution/(credit)			0.0												
Current capital contribution/(credit)			0.0												
PV of annual capital contribution			0.0												
Total PV			**0.0**												
PV Proceeds on disposal of assets - $k			**0.0**												
PV CCA Residual Tax Shield - $k			**73.5**												
PV Working Capital - $k			**1.2**												
PV Capital (after taxes) - $k	(B)	(14,925.3)	**(14,925.3)**												
Cumulative PV Cash Flow (after taxes) - $k	(A) + (B)	2,297.6	**(14,925.3)**	**(14,011.3)**	**(12,930.9)**	**(11,853.3)**	**(10,779.9)**	**(9,712.0)**	**(8,828.5)**	**(7,984.4)**	**(7,176.7)**	**(6,402.7)**	**(5,660.2)**	**(4,947.0)**	**(4,261.3)**

Month	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1	Jan-1
Year	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
			3rd true-up										
	13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Load Forecast (MW)	99.6	101.6	103.6	105.7	107.8	110.0	112.2	114.4	116.7	119.0	119.0	119.0	
Load adjustments (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	97.6	99.6	101.6	103.6	105.7	107.8	110.0	112.2	114.4	116.7	119.0	119.0	119.0
Tariff Applied ($/kW/Month)	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Incremental Revenue - $k	2,366.8	2,414.1	2,462.4	2,511.6	2,561.8	2,613.1	2,665.3	2,718.7	2,773.0	2,828.5	2,885.1	2,885.1	2,885.1
On-going OM&A Costs - $k	(658.0)	(658.0)	(658.0)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)	(822.5)
Ontario Capital Tax and Municipal Tax - $K	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)	(62.8)
Net Revenue/(Costs) before taxes - $k	1,646.0	1,693.3	1,741.6	1,626.3	1,676.6	1,727.8	1,780.1	1,833.4	1,887.8	1,943.2	1,999.8	1,999.8	1,999.8
Income Taxes - $k	(314.2)	(336.5)	(358.3)	(336.0)	(356.9)	(377.5)	(397.7)	(417.8)	(437.6)	(457.3)	(476.9)	(481.2)	(485.1)
Operating Cash Flow (after taxes) - $k	1,331.8	1,356.8	1,383.3	1,290.4	1,319.7	1,350.3	1,382.3	1,415.6	1,450.1	1,485.9	1,522.8	1,518.6	1,514.7
PV Operating Cash Flow (after taxes) - $k	**659.9**	**635.6**	**612.6**	**540.2**	**522.3**	**505.2**	**489.0**	**473.4**	**458.4**	**444.1**	**430.3**	**405.6**	**382.5**
On-going capital expenditures - $k	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative PV Cash Flow (after taxes) - $k	**(3,601.4)**	**(2,965.9)**	**(2,353.3)**	**(1,813.1)**	**(1,290.8)**	**(785.5)**	**(296.6)**	**176.8**	**635.2**	**1,079.3**	**1,509.5**	**1,915.1**	**2,297.6**

Discounted Cash Flow Summary

Economic Study Horizon - Years:		**25**
Discount Rate - %		**5.78%**
		$k
PV Incremental Revenue		29,181.2
PV OM&A Costs		(7,944.1)
PV Ontario Capital Tax and Municipal Tax		(843.0)
PV Income Taxes		(5,404.4)
PV CCA Tax Shield		2,306.8
PV Capital - Upfront	(15,000.0)	
Add: PV **Capital Contribution**	**0.0**	(15,000.0)
PV Capital - On-going		0.0
PV Proceeds on disposal of assets		0.0
PV Working Capital		1.2
PV Surplus / (Shortfall)		2,297.6
Profitability Index*		1.2

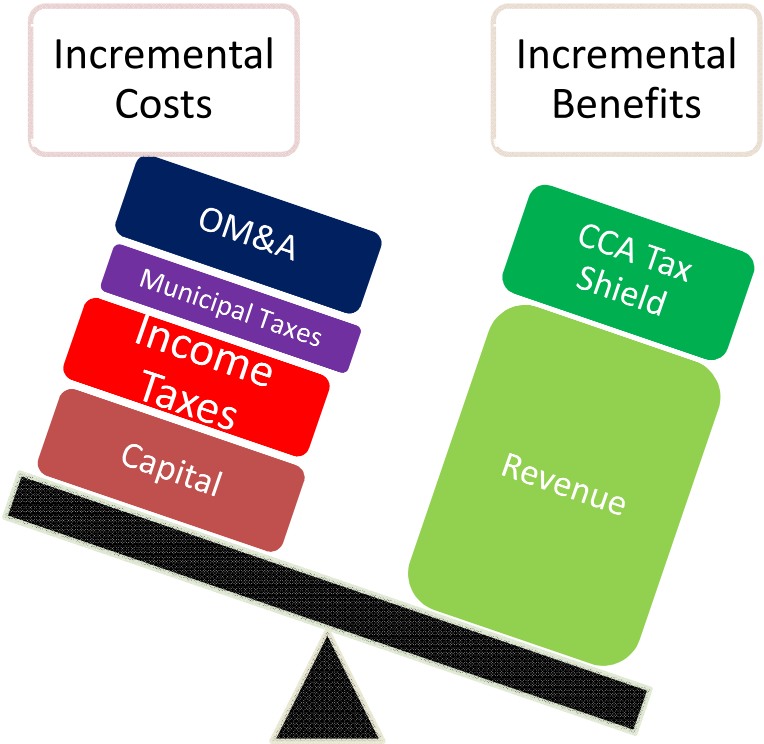
Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

All Revenue and Expenses are brought to Time = 0

Other Assumptions		**Notes:**
In-Service Date:	1-Jan-20	
Municipal Tax	0.42%	Transmission system average
Federal Income Tax	15.00%	Federal corporate income tax
Ontario Corporation Income Tax	11.50%	Provincial corporate income tax
Working cash net lag days	-1.04	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets

Calculation Time Stamp: 01-May-14, 4:12 PM

IEE RESULTS EXPLAINED



- NPV > or = 0 results in no capital contribution
- NPV < 0 requires capital contribution to have a zero NPV
- Ensures Ratepayer is not harmed
- Capital contributions lower Net Book Value of asset

CCRA CONTROL: LOAD TRUE UPS

- True Ups occur at preset periods after in-service, based on risk profile of customer
- Distribution customers are always considered “Low” Risk with 25 year economic evaluation period
- Low risk, true ups occur once project is in service and the 5, 10 and potentially 15 year mark as per 6.5.3c TSC
- Only load is trued up. Other inputs are held constant per TSC s6.5.4
- Additional capital contributions due as required while refunds for an over contribution are paid at final true up – both values are impacted by time-value-of-money

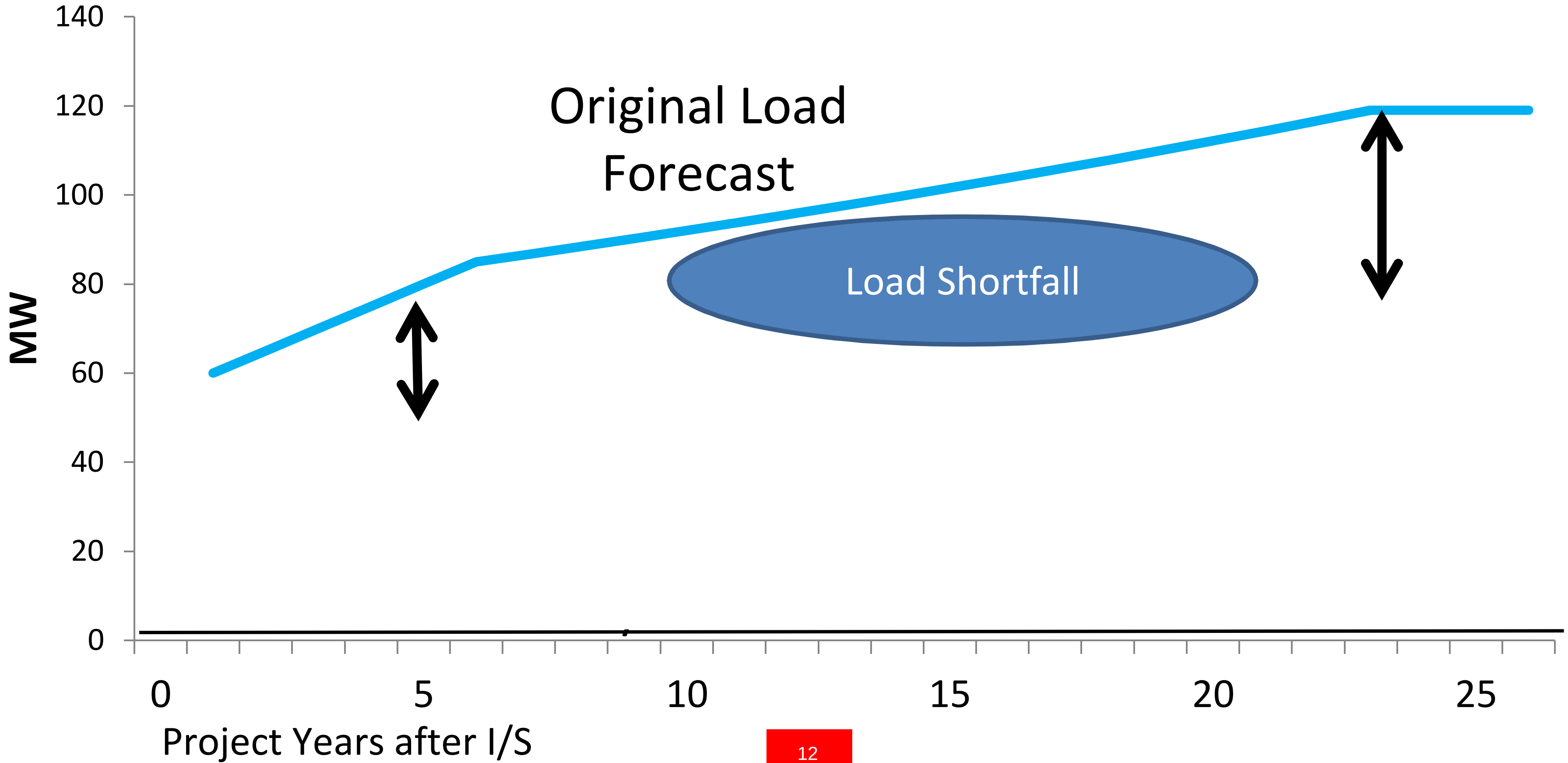
CDM/DISTRIBUTED GENERATION LOAD ADJUSTMENTS

- Per s6.5.8 and s6.5.10. of the TSC, the impact of incremental CDM and DGs may be added to the actual load. Hydro One performs the assessment; customer is not required to perform the calculation

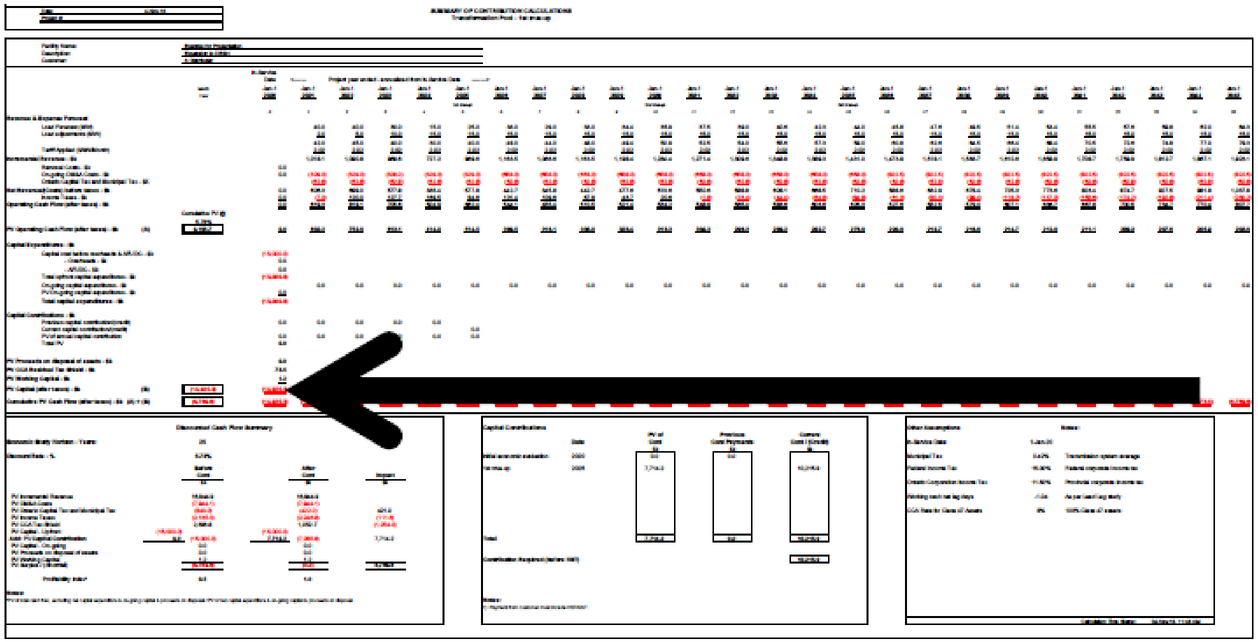
- Customer must provide evidence of CDM/DG impact
  - CDM/DG Load Adjustments resources located at: http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Pages/Getting-Started-2.aspx
  - Customer can choose to decline CDM credits

- Customer provides the impact of future CDM & DG in the updated load forecast

CCRA LOAD TRUE UPS



THE TRUE UP RESULT

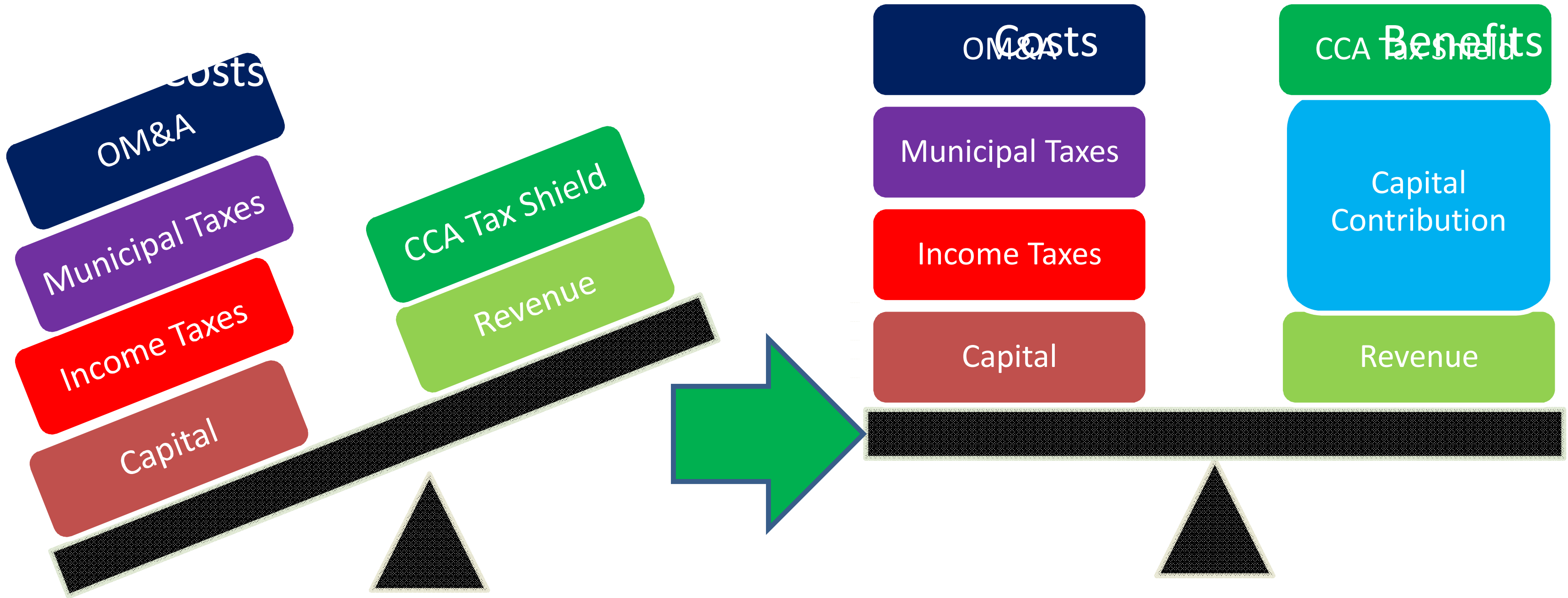


Rates & expenses are based on original inputs. The revised "forecast revenue" is adjusted solely on the changing load. Resulting capital contribution are brought to Time = 0

TRUE UP EXPLAINED

Incremental Costs now exceed benefits

Capital Contribution required to result in NPV = 0



Capital Contribution lowers the Net Book Value of Asset and Hydro One Transmission's Rate base

WHAT IS REQUIRED FROM THE CUSTOMER?

- Confirmation that original load forecast is still accurate or an updated load forecast
- Hydro One is obligated to review the forecast for "reasonableness"
- Customer must include their assumption of CDM/DG in their forecast.
- Supporting documentation for CDM/DG credits
  if required

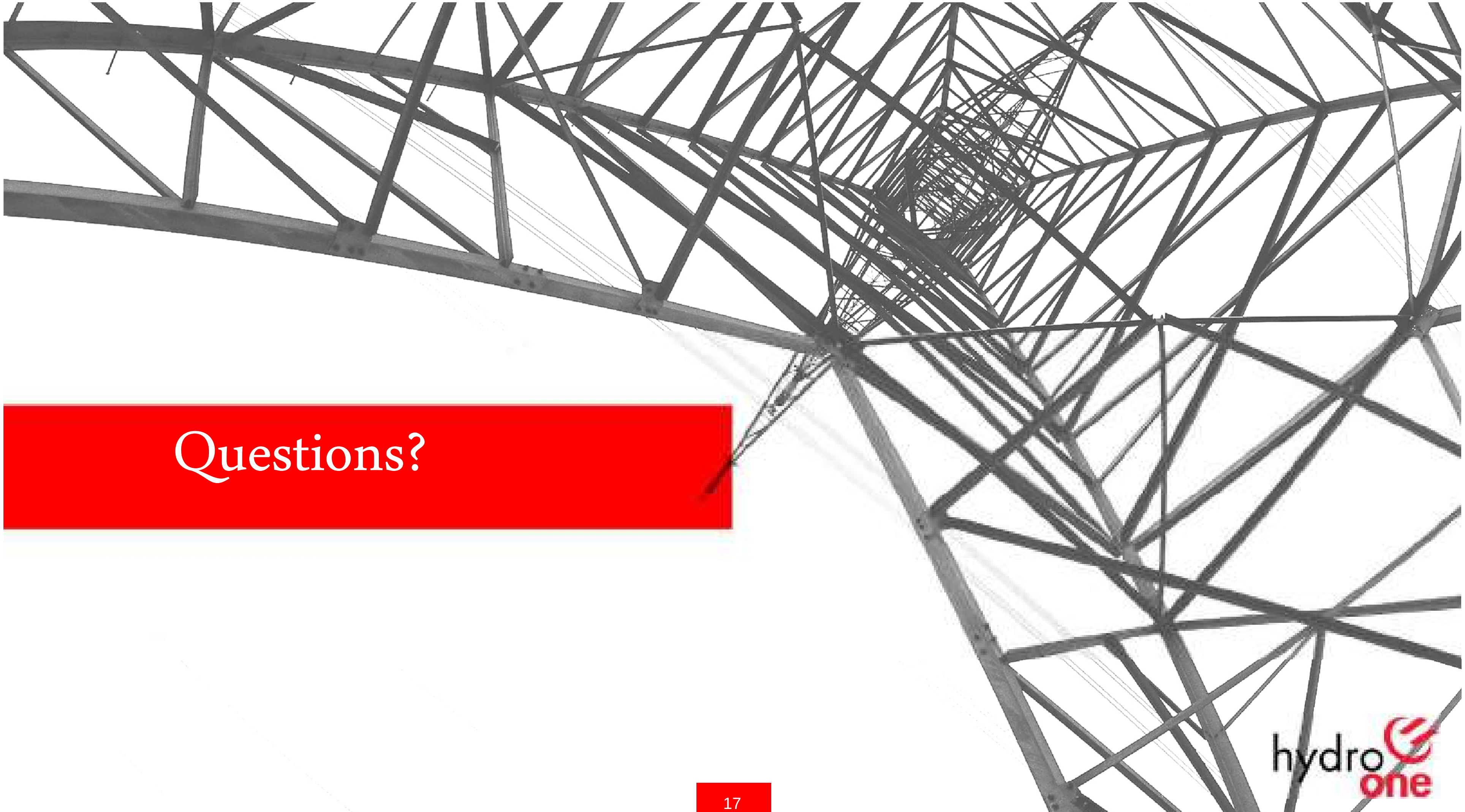
WHAT YOU SHOULD EXPECT FROM HYDRO ONE

- Calculate both the CDM credits and resulting True Up contribution or credit
  - Calculation usually takes 2 – 3 weeks dependent on extent of CDM once complete data set is received

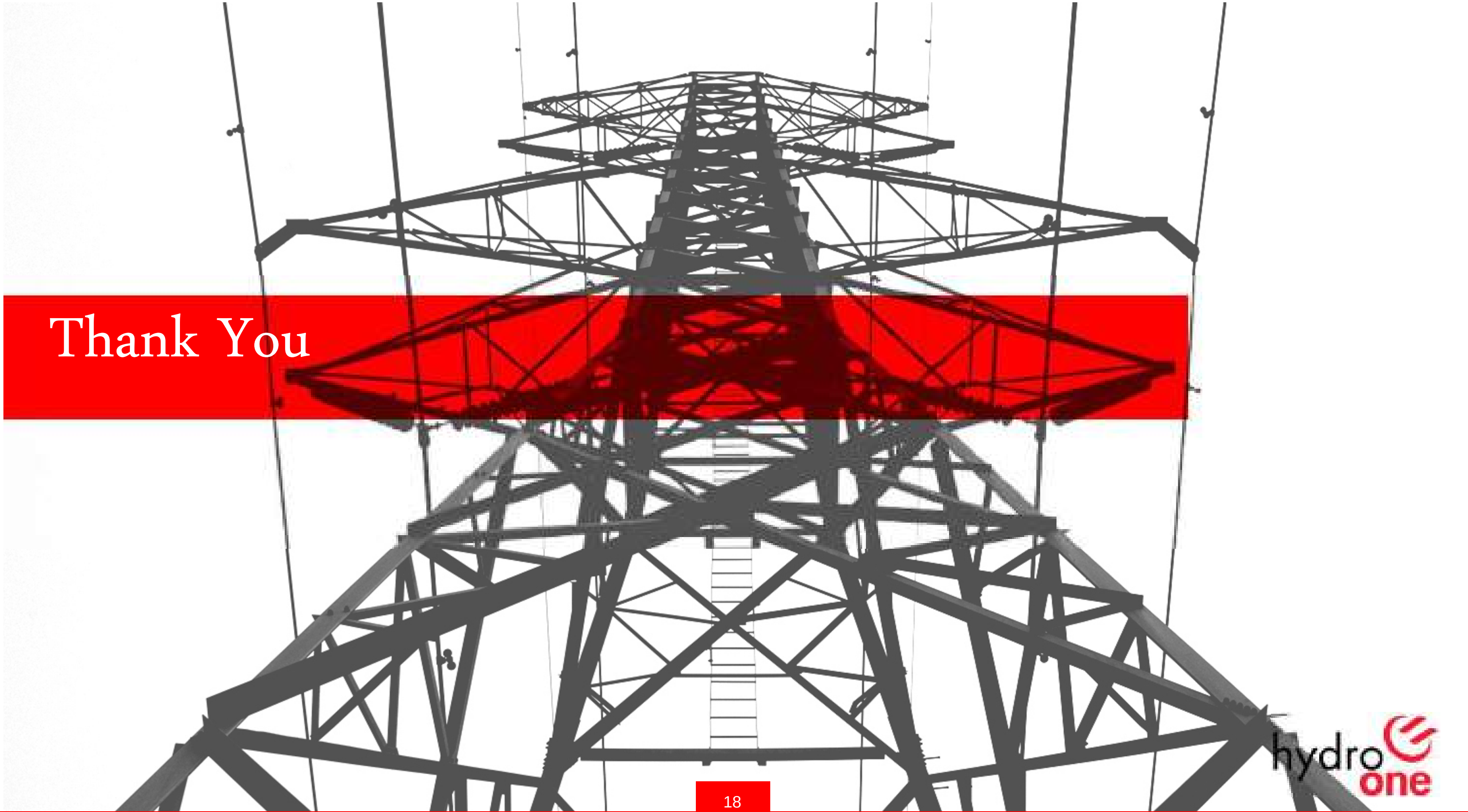
- Will provide CDM credit summary and unlocked copy true up calculations upon request

- Provide a detail explanation of calculation to customer staff and representative

- Will answer Interrogatories from Ontario Energy Board or Intervenors in relation to model design, inputs, and execution



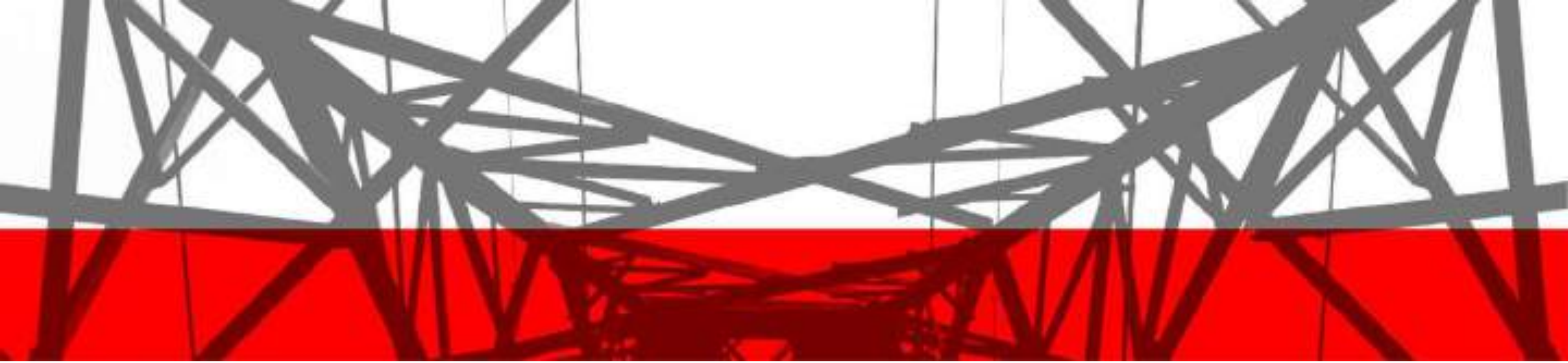
Questions?



Thank You

LARGE CUSTOMER CONFERENCE

Productivity & Operational Efficiency



BILLING & PAYMENT: LOAD DISPLACEMENT GENERATION, NET METERING AND ENERGY STORAGE

William Cheng

Manager, Transmission and Distribution Settlements

Hydro One

CUSTOMER INSTALLING A GENERATOR

- A Customer Impact Assessment (CIA) is needed for installing any load displacement or back-up generator >10 kW as per Hydro One's Conditions of Service

- A Distribution Connection Agreement (DCA) must be executed for connecting any >10 kW generator

RATIONALE FOR LOAD DISPLACEMENT GENERATOR

- A customer wants to reduce their electricity bill, in particular Global Adjustment
  - Class B customers want to reduce the total kWh based Global Adjustment charges
  - Class A customers want to avoid or reduce demand during the IESO system peaks to lower their Peak Demand Factor
- Customer could be incented by IESO to install generator under Conservation Demand Management
- Customer needs to self declare Debt Retirement payment to Ministry of Finance
  - Current forecasted Debt Retirement Charge expiry is March 31, 2018
- Load Displacement generation may impact Class A qualification
  - Please consult Meghan Atkinson (Meghan.Atkinson@HydroOne.com) for more information
- Depending on type and size of the generator, customer may or may not attract Gross Loading Billing

hydro one

POTENTIAL TRANSMISSION AND DISTRIBUTION CHARGES IMPLICATION FOR INSTALLING LOAD DISPLACEMENT GENERATOR

- Depending on the type and size per unit of the load displacement generator, it may trigger Gross Load Billing (GLB) of Transmission Line and Transformation Connection charges, but not Network charge

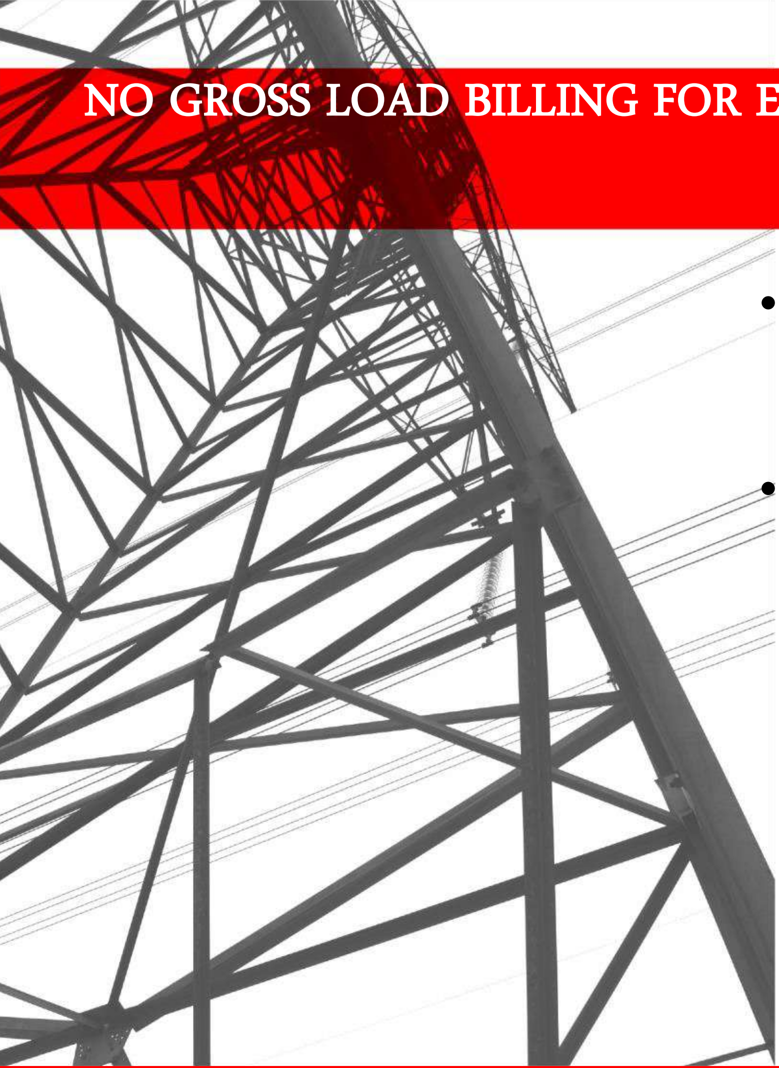
- Gross Load Billing applies to Distribution Common Sub-transmission Rate but not to the General Service Rates

- GLB thresholds: (1 MW for non-renewable and 2 MW for renewable) refer to unit capacity (in the case of solar, inverter capacity), not site capacity
    - Eg. A solar farm with 10 MW (20 x 0.5 MW inverter) capacity would not trigger GLB

- GLB also applies to the incremental capacity of a refurbished legacy generator
    - Eg. GLB applies to the 5 MW incremental capacity of a refurbished 7 MW Legacy generator with 2 MW old capacity

hydro one

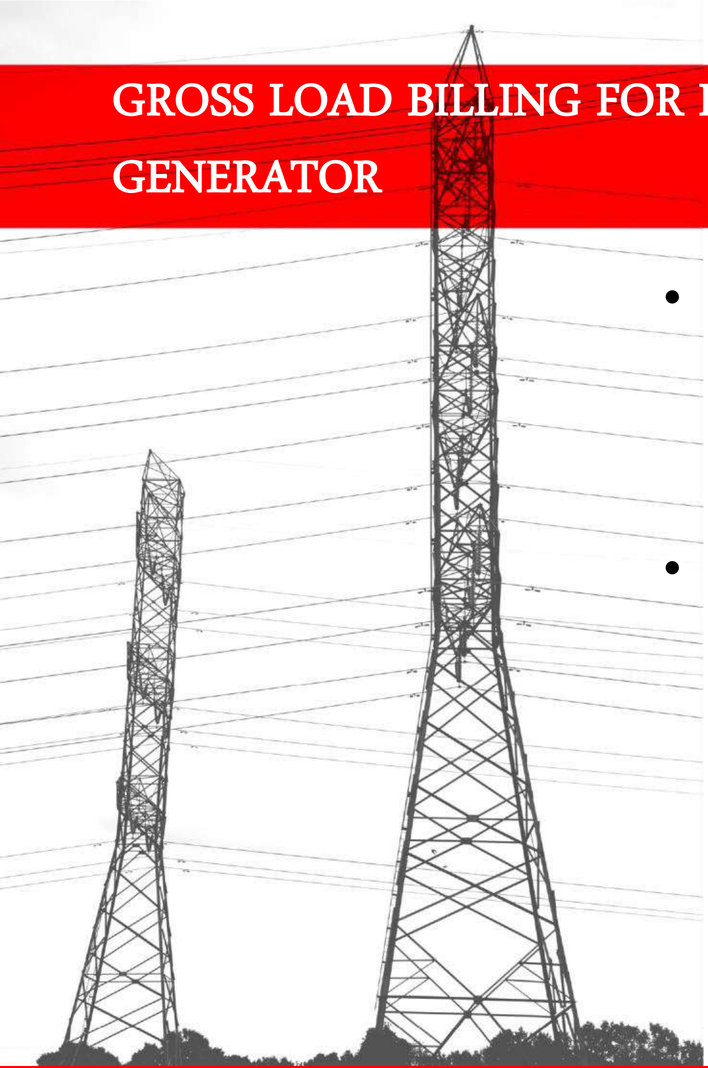
NO GROSS LOAD BILLING FOR EMERGENCY BACKUP GENERATOR



- GLB does not apply to an emergency back-up generators
  https://www.ontario.ca/laws/regulation/r07516

- “standby power source” means equipment that is intended to be used for the purpose of producing power to maintain operating conditions when the power produced by the normal sources of power is cut off or reduced

GROSS LOAD BILLING FOR ISLANDING OPERATION WITH LOAD DISPLACEMENT GENERATOR

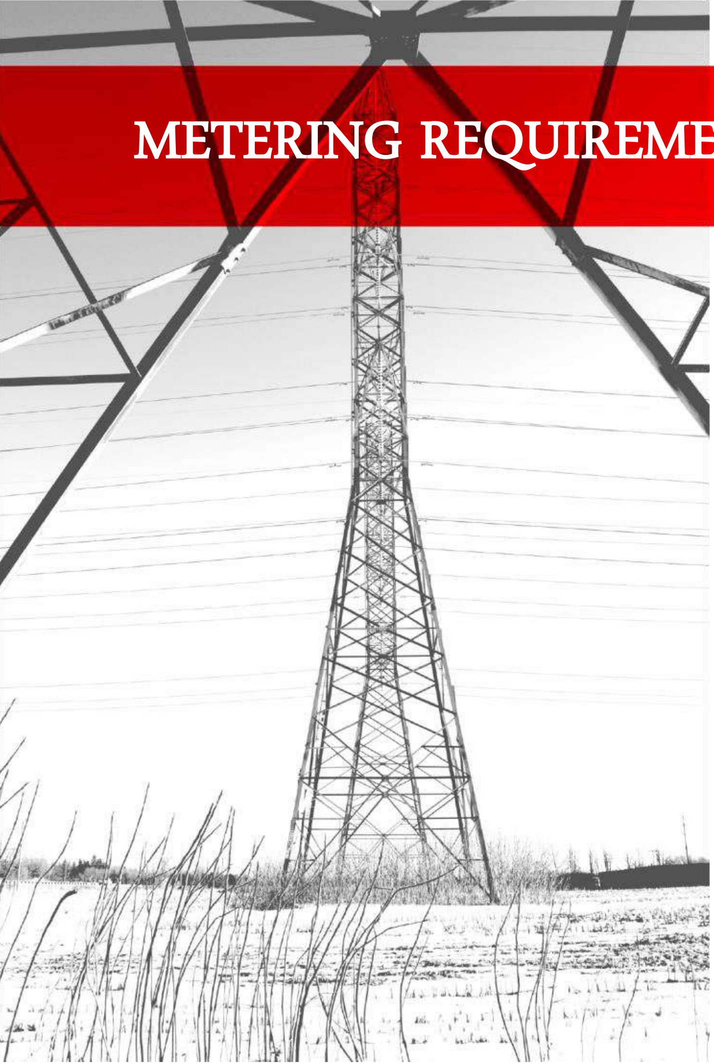


- A Customer with a load displacement generator operating off-grid is still subject to Gross Load Billing if they are connected to the grid for any back-up supply

- For complete off-grid operation, 365/7/24, Hydro One will not Gross Load Bill the customer but will remove all of the distribution assets from the connection and will not provide

  back-up support

METERING REQUIREMENTS



- A retail revenue meter is needed to measure the generator's output
- Hydro One needs access to the meter for on going Gross Load Billing for embedded LDCs
- Customer will need to install the meter for Debt Retirement Charge declaration to the Ministry of Finance

HYDRO ONE GLB BUSINESS PROCESS – CUSTOMER NOTIFICATION

- Hydro One Connection Impact Assessment (CIA) process now includes GLB assessment for any generators with a size of 1MW or more, to make customers aware of GLB eligibility and the settlement impacts

UPCOMING POTENTIAL CHANGES

- OEB is initiating a policy review to address the question of how a commercial and industrial customer should be billed when they have a Load Displacement Generator (LDG) behind the meter

- http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/OEBltr_Gross_Load_Billing_Tx_20160329.pdf

NET METERING – EXISTING FRAMEWORK

- Our Net Metering program is available to any Hydro One customer who generates electricity primarily for their own use from a renewable energy source (wind, water, solar radiation or agricultural biomass) using equipment with a total nameplate rating of **500 kW or less**

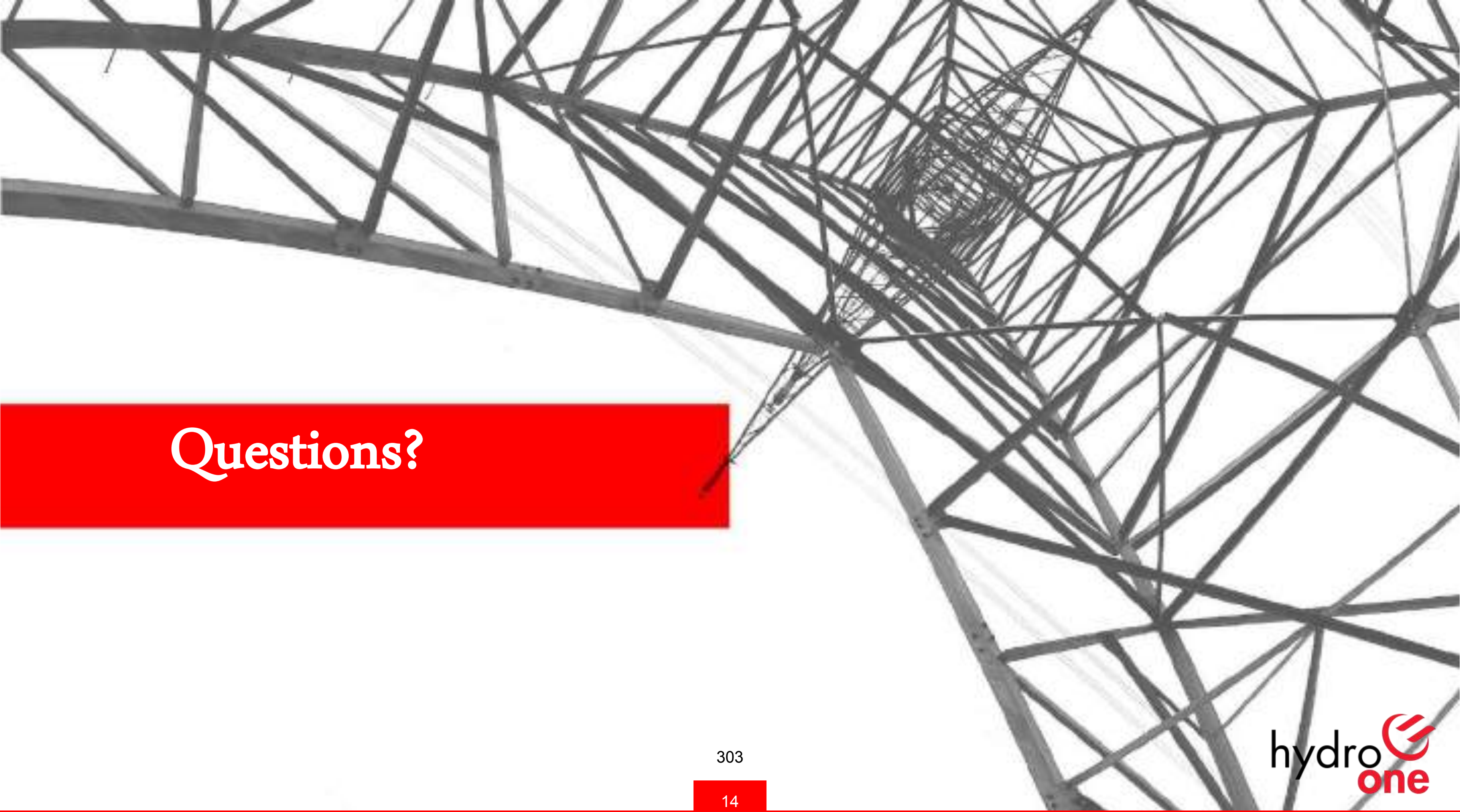
- Net metering allows you to send electricity generated from Renewable Energy Technologies (RETs) to Hydro One's distribution system for a credit towards your electricity costs
  - Excess generation credits can be carried forward for up to 11 months, including the 11th month, to offset future electricity costs

NET METERING – PROPOSED AMENDMENTS

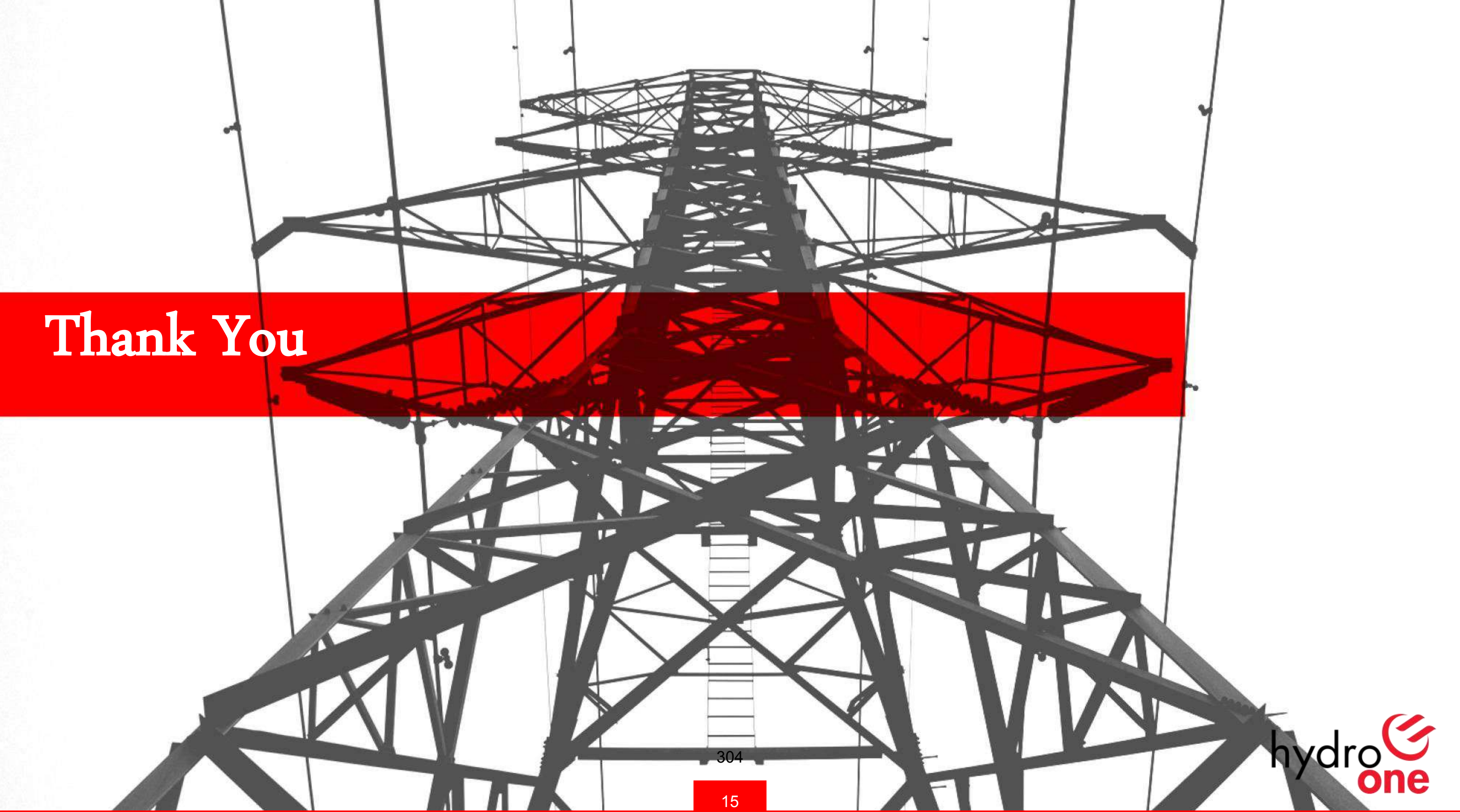
- Remove the capacity limit of 500 kW
- Extend credit carry forward period from 11 months to 12 months
- Virtual Net Metering – credits transfer within multiple accounts within the same LDC within the distance requirement
    - Proposed: 3km
- Pairing of renewable energy sources with energy storage which allows for flexible injection
- https://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTI5NTIx&statusId=MTk2Mjg5&language=en

ENERGY STORAGE

- Energy Storage License is required by OEB
- Proponent is subject to the same Hydro One connection process for a distribution generator
- Hydro One will settle Energy Storage as no contract generator:
  - Bill all charges (delivery, energy and global adjustments) for energy withdrawal from the grid
  - Pay spot prices when injecting power into the grid
- Industry estimates of 20% loss for kwh transaction – for every 100 kwh withdrawn, only 80 kwh injected
- Potential Cost Mitigation if energy storage is allowed as stand alone source for Net Metering – injection will receive both global adjustment and energy credit



Questions?



Thank You

Voice of the Customer – 2016 Large Customer Conference - Action Items

End-users:

- Service timeliness to resolve issues require faster response times and end-users would like to utilize LDC services to restore power faster. HONI engaged with the end user and addressed their concern to their satisfaction.
- End-users would like to resolves issues where their peaks are incorrectly applied to 'on peak instead of 'off peak' per actual usage
- When customers upgrade their facilities for DC Remote trip to a radio medium they requested that HONI help to resolve connection issues in a timely manner.

LDCs:

- Some LDCs requested that the investigation and results of U-Bolt failures be provided to them and to list any future action HONI may take to prevent single contingency events. HONI has complied with this request and further discussions with the concerned LDCs are ongoing. All the defective U-Bolts from the investigation back in 2016 were replaced.
- A few LDCs requested HONI to investigate if the customer # could be extracted at the Low Voltage Bus level. This was investigated and HONI cannot extract this at the Bus Level since the system is not capable. Additionally, other LDCs indicated that would not be willing to share their customer information.
- Some LDCs informed HONI that they are contacted by HONI's customers during power outages or trouble situations.

Generators:

- Outage communication and work bundling was a primary concern for all generators in attendance. The coordination of the data input on outage plans from all generators at the Transmission and Distribution level was reported as being fragmented. HONI's Transmission System Outage Group provides the opportunity for Transmission connected generators to participate. HONI is working on providing a similar forum in order to facilitate better notification of planned outage requirements to Distribution connected generators.

LDAs:

- No major issues were reported.

2016 LARGE CUSTOMER CONFERENCE

EVENT DEBRIEF

AT A GLANCE

Dates: Monday November 21 and Tuesday November 22, 2016
Times: Day 1 (Main Session): 7:00am-4:00pm, Dinner 5:00pm-9:00pm, Day 2 (Breakouts): 7:30am-5:00pm
Venue: Toronto Sheraton Airport Hotel & Conference Centre, 801 Dixie Rd, Mississauga, ON
Audience: Hydro One's Large Customers, including Local Distribution Companies (LDCs), Industrial and End Users, Transmission-connected Generators and Large Distribution Accounts (LDAs)
Format: Day1: All-in-one customer session, Day 2: Breakout sessions for each customer segment (4 different rooms)
Number of attendees: 131 customers across 97 different organizations
Hydro One Contact(s): Graham Henderson (graham.henderson@HydroOne.com), Victor Reynoso (victor.reynoso@HydroOne.com), Tony Yu (tony.yu@HydroOne.com)

Overview

The Large Customer Conference is Hydro One's annual premiere event for large customers. The conference is specifically targeted at the organization's different large customer sub segments – Local Distribution Companies, Industrial End Users, Transmission-connected Generators and Large Distribution Accounts.

This year's event featured a series of speakers and networking discussions that were centered around the themes of Productivity and Operational Efficiency, key elements of Hydro One's transformation into a leading global utility.

Day 1 consisted of key note addresses and presentations by various Hydro One and Independent Electricity System Operator (IESO) executives. Topics included: the Transmission Customer Engagement and Business Plan, Increasing Productivity at Hydro One, Security in the Power Industry and the Long Term Energy Plan (LTEP).

Day 2 included breakout streams specifically targeted at each Large Customer segment. Presentations were delivered by various Hydro One staff, as well as, other industry experts. Topics included: Power Quality, Transmission Reliability, LiDAR and new Hydro One technologies, Net Metering, CCRAs True-ups, the OGCC Control Room, Conservation and Demand Management, and others. Day 2 opened with Voice of the Customer sessions whereby customers openly discussed specific issues and concerns with Hydro One representatives. Those VoC sessions were formally documented and follow-up actions and resolutions will be coordinated by appropriate staff.

In total, 211 attendee's participated, including 131 customers from 97 organizations, and 80 Hydro One staff there to network, liaise and support customers in various capacities.

Overall, the 2016 Large Customer Conference was a huge success. Based on initial conference feedback, customers found the event valuable. There have also been valuable suggestions from attendees related to adding even more value for attendees, including topic, logistical and other suggestions. All feedback is being taken into serious consideration as planning for the 2017 conference has already begun.

Attendance (2015 and 2016)

	2015	2016
Customers	149	131
Staff	67	80
Total	**216**	**211**

Year	End-users	LDC	Generators	LDA
2015	22	75	15	15
2016				

See Appendix A for entire customer list by type

Initial Feedback & Survey Results

Feedback (Rate 1 to 5, 1 being poor, 5 being Excellent)		
Segment	**Avg**	**Responses YTD**
End User	3.88	8
Generator	3.71	7
Large Distribution Account (LDA)	4.33	9
Local Distribution Company (LDC)	4.30	10
Total	**4.09**	**34**

Building Owners and Managers Association Toronto Interrogatory # 73

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

A-05-01 Page: 15 - detail of cost reduction

Interrogatory:

a) Percentage of telephone calls answered on time. Does Hydro One currently record and measure the purpose of each call, eg. bill, emergency, CDM request, etc.?

b) In what year of the five-year rate plan does Hydro One expect to reach its target of answering calls within thirty seconds, eighty percent of the time?

c) Does Hydro One forecast a reduction in call volumes, by what percentage, by what year, due to the investments and process changes, and digitalization measures it proposes to make?

d) What call centre cost reduction does it forecast in each year of the IRP, both capital and OM&A?

e) Are there any precedents to Hydro One proposed investments described at pp 15-16? Please discuss.

f) What increase in FCR has Hydro One targeted for each year in the plan in order to reach eighty-eight percent by 2022? What is the cost of the investment in customer tools and analytics? When will the High Usage Alerts feature be established and operating? How does it work?

g) Please provide a table for each of the custom performance indices showing HONI 2015 and 2016 performance industry average for 2016, and HONI's target for 2022 (or earlier, if applicable).

Response:

a) Yes, the volume of calls, and associated breakdown, are outlined in interrogatory response Exhibit I-2-Staff-001.

b) Hydro One expects to answer calls within 30 seconds, 80% of the time, in each year effective 2017 and beyond.

c) Hydro One forecasts call volumes two months in advance for the purposes of scheduling contact centre employees. There are a number of other factors that cause variations in call volumes year over year, including: policy changes, new initiatives, rate changes, and outages. As such, Hydro One does not forecast call volume percentage reductions associated with investments in future years.

d) The Customer Care OM&A exhibit (Exhibit C1, Tab 1, Schedule 5) assumes annual inflation which is offset by productivity improvements. There is no annual Capital program for the Contact Centre, however, there are a number of discreet initiatives that support Customer Service Operations overall, which are outlined in the Investment Summary Documents.

e) Hydro One's Distribution Rate Application includes several digital investments to address customer feedback. Additional information can be found in the Investment Summary Documents.

f) For Hydro One's First Call Resolution Targets, please refer to Exhibit I-18-SEC-029, Electricity Distributor Scorecard.

Refer to Hydro One's Investment Summary Documents GP-32 for additional information on the proposed investments and the associated costs.

High Usage Alerts, which launched December 2016, works by providing customers with a proactive alert if their bill is trending higher than a pre-determined threshold. This provides greater insight and visibility into the customer's electricity consumption and allows them to better proactively manage their electricity use.

g) Please refer to Exhibit I-18-SEC-029, Electricity Distributor Scorecard.

Consumers Council of Canada Interrogatory # 1

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

None

Interrogatory:

Please describe, in detail, how HON has responded to the customer concerns expressed at the 10 Community Meetings held regarding this Application.

Response:

Please see Exhibit I-2-VECC-1. Hydro One brought subject matter experts to each of the 10 Community Meetings, including customer service representatives. Hydro One representatives answered account related questions, specific concerns in the community, and/or rate application questions.

Energy Probe Research Foundation Interrogatory # 1

Issue:
Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:
A-03-01 Page: 15

Interrogatory:
Preamble: Energy Probe is curious about the timing of Hydro One's three investment plans and the customer engagement activities. It appears that, even though customers repeatedly stressed that bill increases were their number on concern – more than improved reliability – the first plan recommended by the utility's asset managers called for a 7.1% rate increase in 2018 and 3.8% average annual rate increases over the term of the application.

a) Did Hydro One's asset managers make that request before the customer engagement surveys were completed? What were the time frames – i.e. when were the customer surveys completed versus the investment plans?

b) How does Hydro One distribute its customer engagement surveys and findings to its asset managers? Are all asset managers required to review the findings before making recommendations?

Response:
a) No. Please refer to Table 1 of Exhibit I-24-SEC-36 for a detailed timeline of customer engagement and investment plan timelines/milestones.

b) Hydro One shares its customer engagement surveys and findings with its management team in various lines of business that require the information. Investment administrators (asset managers) are required to consider the needs and preferences of customers and the asset and system needs of the distribution system in the development of candidate investments.

Ontario Sustainable Energy Association Interrogatory # 2

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Hydro One Networks Inc. 2018 - 2022 Distribution Rate Application
Community Meeting Report 1. OEB File No. EB-2017-0049

Preamble: "The overall message heard from attendees at the meetings was that the cost of electricity was too high and therefore Hydro One's request for a rate increase should not be approved. There was some confusion about how the Hydro One rate application and the Fair Hydro Plan interacted.

1. The OEB should not approve this request by Hydro One to increase its rates. Reasons given included:
   - Hydro One should find efficiencies instead.
   - CEO and executive compensation should be reduced.
   - Replacement of assets should have already been paid for with revenues in the past (replacement reserve) and new funds are not necessary.
   - Hydro One has been wasting money in the past.
   - Rates in Ontario are the highest in the country creating hardships for customers and forcing business to close or relocate.
2. The salaries of Hydro One's CEO, executives and employees are too high. The CEOs of BC and Quebec Hydro make one tenth of the amount the Hydro One CEO makes. There are too many vice presidents at Hydro One and too many employees were on the "sunshine list" when Hydro One was a part of it.
3. Concerns over reliability and service capacity issues.
4. Disagreement with customer assignments to density based rate classes. Customers who were classified as medium density by Hydro One for years have been reassigned to a low-density classification with higher rates.
5. In a few communities (particularly Leamington and Napanee), MPPs and some consumers said there wasn't enough advance notice about the community meetings. Several attendees said they heard about the meeting from their conservative MPP.
6. Whether the OEB has ever refused a rate increase request and whether it is permitted to do so.

7. Concerns that the OEB does not care about the customer/consumer (OEB accountability).
8. An assertion that in the last Hydro One case, the OEB approved a higher increase than was requested."

Interrogatory:

a) While OSEA understands that Hydro One Distribution focuses on the bill impact of only distribution rates when presenting its plans to community groups, has Hydro One considered providing a better context for these impacts given the rest of the factors affecting electricity bills particularly given that its rural and northern customers are particularly hard hit with higher costs and less reliability then other distributions customers in the province?

b) Did Hydro One's presentation at the community meetings reinforce that the distribution charge does not vary by kWh consumption? If not, why?

Response:

a) Hydro One used a typical customer in its community meetings presentation to show the potential bill impacts of the distribution rate application. To provide better context for the bill impacts, the presenters were prepared to, and did, answer questions about the impacts on customers in different density classifications and who use more or less electricity than the typical customer profile. Customers' bills consists of various components and Hydro One spent some time explaining to attendees at the community meetings, the impact of the Fair Hydro Plan on the various bill components.

   Hydro One also provides bill impact and Fair Hydro Plan impacts on our website for different types of customers.

b) The distribution charge <u>does</u> vary by consumption for all rate classes. Residential customers are in the process of moving to a fully-fixed charge, as mandated by the Ontario Energy Board, but the majority of Hydro One's residential customers will not be at fully-fixed distribution charges until 2023. At some community meetings the fact that residential distribution charges are moving to fully-fixed charges did come up in questions from participants.

OEB Staff Interrogatory # 1

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript Page: 38
At this page Mr. Pugliese indicates that,

> *"…one year after some of this work has started, is that the changes have resulted in a reduction of 100,000 calls related to billing and 73,000 fewer calls related to affordability, and we actually see that trend continuing to drop in terms of our responses back to the call centre."*

Interrogatory:

Please provide a table that shows the reductions in customer calls on a monthly basis broken down by category of calls.

Response:

The volumes of calls answered by an agent are as follows. Billing calls reduced by approximately 100,000 in 2017 and calls related to affordability / collections declined by approximately 73,000.

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Billing	42,343	33,501	37,718	29,053	37,375	36,169	34,984	40,240	37,006	36,471	35,272	26,994	427,126
Power Outage	31,886	17,143	25,209	30,318	29,481	35,812	40,687	39,824	24,869	37,657	21,942	18,957	353,785
Moving	8,722	7,573	10,225	9,815	15,172	16,274	15,299	14,773	11,776	12,224	10,724	6,338	138,915
Contractor	11,667	9,735	12,211	11,396	13,255	12,053	12,045	13,292	12,576	12,359	10,432	6,635	137,656
Collections	24,590	23,259	24,698	17,642	26,723	27,052	25,131	24,050	22,728	22,412	23,424	13,273	274,982
Other	353	315	265	256	361	388	325	545	334	259	755	302	4,458
BCC	1,697	1,506	1,885	1,237	1,555	1,623	1,388	1,518	1,649	1,640	1,471	1,043	18,212
Total	**121,258**	**93,032**	**112,211**	**99,717**	**123,922**	**129,371**	**129,859**	**134,242**	**110,938**	**123,022**	**104,020**	**73,542**	**1,355,134**

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Billing	44,842	43,562	44,775	44,658	42,147	44,613	45,190	52,442	49,893	46,081	43,359	33,610	535,172
Power Outage	18,018	27,077	38,645	14,659	19,422	31,092	38,368	35,796	19,817	21,110	22,799	18,750	305,553
Moving	6,779	6,536	8,268	10,207	13,870	16,770	15,841	16,286	15,503	14,668	12,822	8,194	145,744
Contractor	12,303	10,512	12,046	14,565	15,772	16,791	16,278	17,866	17,967	16,401	14,779	9,817	175,097
Collections	23,760	21,190	27,430	36,639	37,197	34,531	27,935	33,400	33,315	28,889	30,932	17,983	353,201
Other	906	733	692	602	461	392	353	475	499	379	448	367	6,307
BCC	1,506	1,367	1,533	1,716	1,586	1,450	1,223	1,472	1,480	1,420	1,494	1,185	17,432
Total	**108,114**	**110,977**	**133,389**	**123,046**	**130,455**	**145,639**	**145,188**	**157,737**	**138,474**	**128,948**	**126,633**	**89,906**	**1,538,506**

1

OEB Staff Interrogatory # 2

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 41
At this page Mr. Pugliese testifies,

> *"….we are the first utility to offer service guarantees. So, if we make a commitment to do a reconnect, to do a move in and move-out, if we fail to meet that within a set time frame, there is a service guarantee that we will give to the customer and a credit, and that is $75.*

Interrogatory:

a) Please provide a list of the services that Hydro One's "service guarantee" would cover.

b) Please describe in detail how this service guarantee would work for a typical customer.

c) Are there specific criteria the customer must meet to qualify for this service guarantee?

d) What is the total amount budgeted for 2018 for this service guarantee credit?

Response:

a) If Hydro One does any of the following, Hydro One will credit the affected customer's account $75:
   i. miss an appointment with a customer;
   ii. fail to connect the new service within five business days of all connection requirements being met; and
   iii. fail to return the customer's phone call within one business day

b) Hydro One's service guarantees are outlined below:

i. **Miss an Appointment with a Customer –** Hydro One may schedule an appointment for a member of the field staff to meet with the customer regarding planned work, or to determine the requirements for unplanned work or a new service connection. If Hydro One sets an appointment for a morning or afternoon visit and the appointment is missed, Hydro One will automatically credit the affected customer's account with $75. This service guarantee will not apply for design consultations which do not result in a connection and a customer account.

ii. **Fail to Connect the New Service within Five Business Days of All Connection Requirements Being Met –** If (a) all the connection requirements have been met and (b) Hydro One does not connect the power within five business days, Hydro One will automatically credit the affected customer's account with $75. This service guarantee will not apply if Hydro One and the customer have mutually agreed to connect at a date later than five business days or the service connection is >750V or for distributed generation.

iii. **Fail to Return the Customer's Phone Call Within One Business Day –** When a customer's phone call is escalated in the call centre, Hydro One may schedule a return phone call. If the return phone call is not made within one business day, Hydro One will automatically credit the customer's account with $75.

c) If Hydro One fails to meet any of these service guarantees, Hydro One will automatically credit the affected customer's account with $75. Additional information can be found on Hydro One's website, including exceptions and the conditions of service: https://www.hydroone.com/about/corporate-information/our-service-guarantees

d) Hydro One has budgeted $25,000 to fund service guarantees in 2018.

OEB Staff Interrogatory # 3

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 41

At this reference, Mr. Pugliese indicated that Hydro One had returned $12 million in security deposit value back to customers.

Section 2.4.9 of the Distribution System Code (DSC) sets out the circumstances under which a distributor may require a security deposit for different classes of customers.

Sections 2.4.22 – 2.4.25 set out the process for the review and adjustment or return of security deposits.

Interrogatory:

a) Please confirm that the security deposit amounts returned to customers were not held by Hydro One for periods longer than those set out in the DSC. If this cannot be confirmed, please provide an explanation.

b) Please confirm whether these security deposits were returned earlier than the time periods set out in the DSC. If so, please provide:

   i. Hydro One's time period for returning the deposit by customer class.
   ii. The reasons for returning these customer deposits and how Hydro One addressed the payment risk that a security deposit represents.

c) Has Hydro One made a permanent adjustment to its security deposit policy and defined its new criteria formally? If so, please provide the policy and outline how it is has changed.

Response:

a) Security deposits returned to customers were not held by Hydro One for periods longer than those set out in the Distribution System Code (DSC).

b)

i. Hydro One no longer requires security deposits from residential customers. With respect to General Service customers, security deposits are returned after one year if the customer is deemed to have a of "good payment history", as defined by the DSC.

ii. With respect to residential customers, the DSC currently requires utilities to apply a residential customer's security deposit to an overdue balance prior to the issuance of a disconnection notice. This requirement reduces the effectiveness of security deposits as a tool to mitigate bad debt for residential customers. Furthermore, operational costs associated with administering residential security deposits (i.e. calls, letters, escalations) were high. Hydro One will continue to work with customers in arrears to establish payment arrangements and ensure customers are aware of financial assistance programs. As such, Hydro One is not assuming greater payment risk with respect to accounts receivable.

With respect to General Service customers, Hydro One believes 12 months of payment history is a good indication of the customer's ability to pay. If a customer has 12 months of good payment history, any security deposit that has been collected will be returned to the customer. Hydro One will continue to request security deposits for new General Service customers or existing General Service customers who fall into arrears and no longer meet the good payment history criteria.

c) Hydro One has formally changed its policy to reflect the changes outlined above. The new security deposit policy is also outlined on Hydro One's website as of April 2017. Hydro One is currently in the process of updating its Conditions of Service, which will include the new changes to its security deposit policies.

OEB Staff Interrogatory # 4

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 42-43

At this reference, Mr. Pugliese indicated that Hydro One had changed its collections process from 4 stages to 8 stages. He also indicated that in 2014 accounts receivable were $194 million, which were reduced to $86 million in the most recent quarter of 2016.

Interrogatory:

a) Please provide an update to reflect the most recent quarterly amount.

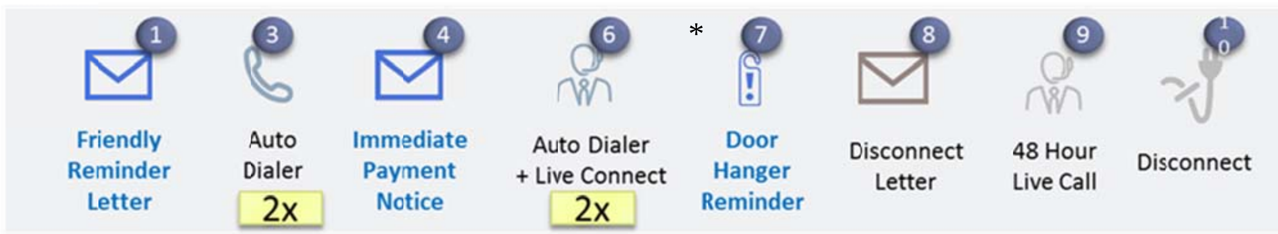
b) Please provide a more detailed account of how the collections process was changed, what the additional stages are and why this has resulted in lower levels of overdue accounts.

c) Please provide a more detailed accounting of the reduction in accounts receivable balances with a table which shows the trend of the reductions.

Response:

a) 2014 accounts receivable were $194 million, which were reduced to $86 million in the third quarter of 2017.

b) The Distribution System Code requires a utility to send a customer a disconnection notice and telephone call 48 hours prior to disconnection. Hydro One has found that more frequent contact with customers results in a reduction in overdue accounts receivable. Hydro One also reaches out to customers soon after they miss a payment, which provides customers more time to manage their arrears or arrange an affordable payment plan. Hydro One's residential collections process is outlined in the diagram below.



** Step 7 is completed in certain circumstances*

c) Hydro One's historical overdue accounts receivable is provided below.

	2014				2015				2016				2017		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
A/R ($M)	$158	$179	$194	$181	$194	$184	$158	$148	$152	$132	$114	$117	$116	$104	$86

OEB Staff Interrogatory # 5

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 43

At this reference, Mr. Pugliese indicated that Hydro One reconnected 400 dwellings that were inhabited of the 1,400 dwellings that had been disconnected. In addition, he testified that 60% of these dwellings are still connected today.

Interrogatory:

Please provide a more detailed account of how this process was conducted and the key aspects or learnings for Hydro One in conducting this exercise.

Response:

In December 2016, Hydro One introduced a Winter Relief program to assist some of its most vulnerable customers. The program identified all customers who had been disconnected for non-payment prior to the commencement of Hydro One's voluntary winter moratorium. Outreach was made to every customer through a number of channels, including mailed letters, outbound calls, and site visits to individual properties.

If Hydro One was able to contact a customer, their premise was reconnected immediately, free of charge, and Hydro One developed an achievable payment plan to get customers back on track. In addition, Hydro One enrolled customers into assistance programs, such as the Low-Income Energy Assistance Program, Ontario Electricity Support Program, and Home Assistance Program. The remaining premises that were not reconnected were deemed to be unoccupied based on Hydro One's site visit.

A few of Hydro One's key findings are detailed below.

1. Robust customer outreach through a variety of channels – Hydro One had difficulty contacting some customers. As a result, the team used a variety of communication channels to locate the customer, including field visits to the premise.

2. Electrical Safety Authority (ESA) Inspections – Some premises that were disconnected for a period of time required ESA inspection before Hydro One could reconnect. As such, the ESA inspections delayed the process, and in a number of instances, the ESA found a number of electrical issues that needed to be repaired prior to reconnection.

OEB Staff Interrogatory # 6

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 49

Interrogatory:

At this reference, Mr. Pugliese indicated that Hydro One will be introducing customer-selected due dates allowing the customer to select the due date by which it wants to pay the bill in the given month.

a) Please indicate whether this option will be available to all customer classes. If not, please identify the classes to which it will be made available and explain why it would not be universally available.

b) Would this require a major adjustment to Hydro One's billing system to meet the customer's request for a specific due date and to also meet the requirements of section 2.6 of the Distribution System Code – Bill Issuance and Payment.

c) Are there incremental OM&A costs involved in this change?

Response:

a) Customer-selected due dates will be available to all low volume customers (i.e. mass market customers) who are on time-of-use rates. The viability of this service is predicated on reliable smart meter connectivity and having daily access to meter-read data. As such, this service will not be available to customers that are covered by Hydro One's TOU exemption (EB-2012-0384).

b) The implementation of this service would not require a major modification to Hydro One's billing system. This service would be fully compliant with all existing regulations, including section 2.6 of the Distribution System Code, as customer billing frequency and timelines to pay would be maintained.

c) The initiative will not require any material incremental OM&A to support its implementation. Existing customer communication channels and tactics will be used to enhance customer awareness of this service.

OEB Staff Interrogatory # 7

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 49-50
Exhibit B/Part B/ISD GP-31 (Prepaid Meters)

Interrogatory:

At the Presentation Day, Mr. Pugliese indicated that Hydro One would never force the pre-paid meter option on any customer and that some customers have requested the pre-paid meter option and others have shown a preference for the load limiter option. At Exhibit B, Hydro One has indicated that it plans to commit $6.1 million in capital to a pre-paid meter project in 2022.

a) Please indicate the degree to which customers prefer the prepaid meter and load limiter options, and in particular:
    i. How many customers have requested prepaid meters? Were these requests unsolicited? What were the circumstances under which the requests were made?
    ii. How many customers have provided unsolicited requests to have a load limiters installed?
    iii. How many customers have provided unsolicited requests to keep a load limiter in lieu of complete reconnection?
    iv. What is Hydro One's current policy on the use of load limiters? Would this policy change under the proposed pre-paid meter program?

b) How will the planned prepaid meter program work in order to allow alternate arrangements to be made for payments (e.g. arrears management plans)?

c) Currently the LEAP program is designed to help pay arrears and maintain connection. It is generally accessed once the consumer receives a disconnection notice. If the consumer is on pre-paid meter service, how would the LEAP be used to provide credits to keep the electricity on?

d) Assuming that the meter would automatically disconnect when the credits run out, how would this be consistent with the disconnection requirements in the various codes and any legislative and/or regulatory restrictions on disconnections in the winter months?

e) How would this program work for special situations such as customers that have specific medical needs for electricity service?

f) What is the rationale for introducing the pre-paid meter program in 2022?

g) Section 53.16(1) of the Electricity Act in association with O. Reg. 525/06 states that when a distributor replaces an existing meter for residential or general service customers, the meter must meet the Functional Specification for Advanced Metering Infrastructure. Will these pre-paid meters meet the “functional specifications”? If not, how will Hydro One resolve this conflict?

h) Section 3.4 of the Standard Supply Service Code states that customers with eligible time-of-use meters must be charged using time-of-use pricing. Will these pre-paid meters be able to charge customers based on time-of-use pricing? If not, how will Hydro One resolve this conflict?

i) If pre-paid meters were to charge based on time-of-use, how would customers reasonably be able to calculate the amount of pre-paid credit required and/or available to cover a specific period given changes in pricing, use and timing?

j) Would pre-paid meters be able to shift between pre-paid mode and “regular” mode to ensure a consumer was not effectively disconnected during winter if unable to purchase new credits?

k) How would consumers “purchase” credits for pre-paid meters? If it is internet based, has Hydro One taken into consideration the complexities and service issues associated with internet access in remote communities? If consumers are able to purchase via credit card, has Hydro One taken into account the limitations on access to credit cards for lower income households?

l) How would fixed charges, such as the monthly delivery fee, be billed for pre-paid meter customers? If a pre-paid meter customer did not use any electricity in the month, would they still be charged a monthly delivery fee?

m) How would OESP and/or any other similar support programs be applied for customers with pre-paid meters?

n) Has Hydro One undertaken a risk-analysis to identify potential issues with pre-paid meters? If so, please provide details on what risks were identified and any action plans Hydro One has developed to mitigate these risks.

Response:

a)

i. Hydro One has received a few unsolicited requests from customers regarding how they can take advantage on the use of pre-paid meters. Data from other Ontario utilities and other jurisdictions indicates, including Woodstock, that when offered the choice of prepaid metering, uptake rates can be as high as 20%.

ii. Hydro One has received a few unsolicited requests from customers to have a load limiter installed.

iii. Hydro One has received a few unsolicited requests to keep load limiters installed in lieu of complete reconnection.

iv. Hydro One no longer installs load limiters as a collections measure. This policy will not change after the proposed pre-paid meter program is implemented.

b) Enrolment in prepaid meters is completely voluntary. In advance of the pre-paid meter deployment in 2022, Hydro One will ensure it is compliant with all regulations, legislations, and standards at that time, regardless of the type of meter at the premise. This includes:

- payment arrangement eligibility (as per OEB regulation)
- financial assistance programs (i.e. LEAP and OESP)
- provincial legislation (i.e. winter moratorium for residential customers)
- internal policies (i.e. Winter Relief)
- Electricity Act regulations
- Measurement Canada requirements
- Standard Supply Service Code (i.e. Time-of-Use pricing)
- Billing requirements (i.e. electricity, delivery, regulatory, taxes)

c) Refer to part b).

d) A disconnection would not automatically occur when a customer's credits run out. Hydro One will continue to follow existing processes with respect to multiple touch points prior to any disconnection.

e) In advance of the pre-paid meter deployment in 2022, Hydro One will create a vulnerability check as part of the eligibility assessment in order to determine if a pre-paid meter is in the best interest of the customer and their specific circumstances, after exploring other options.

f) Hydro One plans on introducing pre-paid metering in 2022 to ensure Hydro One has enough time to develop appropriate policies and procedures, complete field testing, and secure appropriate equipment and software.

g) Refer to part b).

h) Refer to part b).

i) Time-of-use customers with a pre-paid meter will continue to have access to tools that predict electricity usage and consumption patterns, including the time-of-use portal, high usage alerts, budget billing, and CDM.

j) Refer to part b).

k) Hydro One customers with pre-paid meters will have the same payment options available to them as non-pre-paid metered customers, including: bank, internet banking, telephone, credit card, etc.

l) Refer to part b).

m) Refer to part b).

n) In advance of the pre-paid meter deployment in 2022, Hydro One intends to complete a detailed risk assessment, including a review of all policies, soliciting customer input and feedback, and appropriately engaging with stakeholders.

OEB Staff Interrogatory # 8

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 44

Interrogatory:

At this reference, Mr. Pugliese indicated that Hydro One had just launched a new bill design. Please provide a copy of the new bill, description of the new bill presentation and outline the changes made and why those changes were made. Please also provide initial customer feedback, if available, on the new bill design.

Response:

A sample of the new bill is included on the last 2 pages of this response.

The new bill design is being implemented in response to customer feedback that the current bill is difficult to understand. Before the new bill design was launched, Hydro One's survey results indicated that approximately 40% of customers found the bill difficult to understand. The design of the new bill was grounded in customer behaviour research and underwent extensive customer testing with 4,800 of Ontario electricity bill payers, of which 3,130 were Hydro One customers

The key changes to the bill are detailed below.

- Prioritized key information deemed important by customers on the first page to improve ease of comprehension, specifically:
    - What do I owe?
    - How much did I use?
    - When is it due?
    - Who do I contact if I have a question?
    - Key information to be aware of.
- Tested multiple ways to improve customer comprehension of budget billing and instalment plans.
- Enhanced font size and key graphics to make it easier and quicker for customers to find information that they are looking for.

- Tested multiple ways to present the more detailed information on page two of the bill, including implementing a more intuitive time of use graphic and enhanced sequencing of related information in a format that made more sense from a customer comprehension perspective.
- Revised and simplified language to make information easier to read and understand for customers.
- Restructured the definitions for line items to make it easier for customers to relate to and understand where their dollars are being spent.
- Configured the bill layout in a modular format to improve speed to market for future changes.

Hydro One is rolling out the new bill design in a staged manner. It will take until mid-March 2018 to be fully deployed to all customers. As a result, formal customer satisfaction results are not available at this time. At this point, the introduction of the new design has not generated any adverse feedback.

Please see Exhibit I-2-Staff-9 for additional information on the bill redesign initiative.

hydro one

[CUSTOMER NAME]

Your account number is: **1234 5612 3456**

This statement is issued on: **December 28, 2017**

Your Electricity Statement

For the period of: November 23, 2017 – December 21, 2017

What do I owe?

$144.77

See reverse for a summary of how we calculated your charges

How much did I use?

You powered your home with

1,000 kWh

of electricity this period

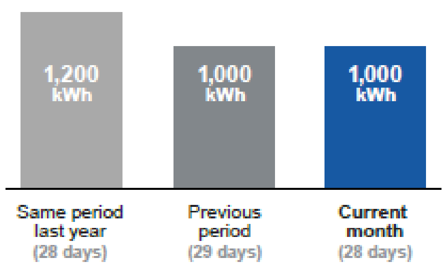
When is it due?

Jan 16, 2018

What does my electricity usage look like?

Your usage has **decreased by 17%** compared to the same period last year.

Find out more by logging into ***my*Account** at www.HydroOne.com.



What do I need to know?

Ontario's Fair Hydro Plan saved you $83.24 on your bill. This amount includes the 8% Provincial Rebate.

For billing, quick answers, and much more, visit **www.HydroOne.com.**

For emergencies or reporting outages **1-800-434-1235** (24hrs)

For service inquiries and payments **1-888-664-9376** Mon to Fri 7:30 a.m. – 8 p.m.

Hydro One Networks Inc.
PO Box 5700
Markham, ON L3R 1C8

Please return this slip with your payment

Your account number: 1234 5612 3456

hydro one

Total amount you owe **$144.77**

Amount enclosed **$**

T1 (A)
XX 101
CUSTOMER NAME
CUSTOMER NAME 2
ADDRESS FIELD, ADDRESS NOTES

ELECTRICITY COMPANY
RETURN ADDRESS 2
ADDRESS FIELD, ADDRESS NOTES

What am I paying for?

Balance carried forward **$0.00**
Amount due from your previous period $207.42
Amount received - Dec 17/17 -$207.42
Your adjustments .... **-$5.00**
Your electricity charges **$149.77**

Total amount you owe **$144.77**

Powering 32 NORTH STREET

Point of Delivery: 50150150 — Residential Medium Density

Electricity **$82.16**

This is the cost of generating the electricity you used this period. Usage is measured in kilowatt-hours (kWh) and depends on the wattage of devices you use and how long you use them. The Ontario Energy Board (OEB) sets the cost per kWh and the money collected goes directly to the electricity generators.

Delivery **$56.03**

This is the cost of ensuring you have reliable power when you need it. Hydro One collects this money to build, maintain, and operate the electricity infrastructure, which includes power lines, steel towers and wood poles covering 960,000 sq. km. A portion of this cost is fixed and a portion varies depending on the amount of electricity used.

Regulatory Charges **$4.45**

The Independent Electricity System Operator (IESO) uses this money to manage electricity supply and demand in the province, which is necessary to ensure that there is enough electricity to meet Ontario's needs at all times.

HST (12345-1234-RT1111) **$18.54**
8% Provincial Rebate .... **-$11.41**
Total of your electricity charges **$149.77**

Your Adjustments **-$5.00**

Conservation program credit -$5.00

Meter Number	Current Reading	Previous Reading	Difference	Usage in kWh
J1234567	**Dec 21/17** 2,701	**Nov 23/17** 1,701	1,000	(x1) = 1,000

This statement contains account adjustments.

If payment is not received by Jan 16/18, a late payment charge of 1.5% compounded monthly (19.56% per year) will be calculated from the statement date and applied to your account.

What is my Time-of-Use breakdown?

Nov 23/17 to Dec 21/17	Usage (kWh)	Rate (¢)	Amount
On-Peak	180	13.2	$23.76
Mid-Peak	170	9.5	$16.15
Off-Peak	650	6.5	$42.25

What is my Time-of-Use schedule?

Winter: Weekdays – Nov 1 to Apr 30

Weekends & holidays are always Off-Peak

Go paperless!

Save time and trees with paperless billing

Convenient, secure online access to your account 24/7 – and it's better for the environment.
HydroOne.com/myAccount

24/7

Hydro One - How the System Works

Hydro One's role is to make sure that Ontario's electricity can flow directly to you, our customers, through our system safely and reliably.

Energy Saving Tip

Phantom Power

Electronics use energy even when off. Plug them into power bars with timers or auto-shutoff to lower energy use.

OEB Staff Interrogatory # 9

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 18 and page 44
Exhibit C1/Tab 1/Schedule 5, pg 13, Table 11: Operational Effectiveness Outcomes

Interrogatory:

As noted above, Hydro One witnesses mention the bill redesign and its launch in late 2017. Table 11 indicates that the redesign "will make it easier for customers to understand their bill and increase their understanding of their electricity consumption."

a) The Hydro One witness mentioned that 40% of customers found that the current bill was confusing. What was the source of this statement?

b) Were there additional reasons for pursuing a bill redesign?

c) Please summarize the changes made to the bill design and why each specific change was made.

d) What was the cost of this bill redesign and are any of the costs of this project proposed to be recovered in 2018 rates?

e) What are the benefits expected from this bill redesign? Is customer satisfaction expected to improve? If so, by what amount? Are call volumes expected to be lower? Again by what amount? Would this lead to lower staffing and other costs and if so, to what extent?

f) Have bills also been redesigned for General Service and Large User customers? If so, what was the rational for this redesign and what are the benefits expected?

g) As Hydro One has shared this bill redesign with other distributors, what is the status of the bill redesign project in the distribution sector?

h) After the 2017 bill redesign completed in 2017, why is Hydro One planning another bill redesign for 2021/2022, as shown at ISD GP-29 (Customer Service Billing Investments)? What additional features are planned in the 2021/2022 redesign not already in 2017 redesign?

Response:

a) Hydro One conducts surveys on a regular basis across various customer segments to gain an understanding of the key drivers impacting customer satisfaction. All research is conducted by independent experts, thereby ensuring results are unbiased. The referenced statistic is based on results from the bi-annual Residential and Small Business survey.

b) Hydro One redesigned the bill in order to:
   - improve customer comprehension of information presented on the bill;
   - improve information retention by customers; and
   - replace vendor unsupported/antiquated bill print tools and applications.

c) Please refer to Exhibit I-2-Staff-8.

d) The cost of the Bill Redesign in 2017 was $9 million, broken down as follows: actual bill graphical design (1%); customer and behavioural science research (6%); replacement of out-dated bill print hardware and applications (26%); system design and testing (54%); and customer communication, migration and call centre staff training (13%). There will be no impact to 2018 rates as a result of this initiative.

e) Hydro One expects increased customer comprehension of their bill and electricity consumption, leading to improved customer satisfaction with service delivery. The redesigned bill will also encourage energy conservation by providing customers information on how they can manage their usage better to take advantage of off-peak rates. Furthermore, the new modular design will allow Hydro One to implement modifications faster to meet future regulatory and customer need driven changes.

   It is anticipated that with the new design, customers comprehension about their electricity consumption will increase, thereby reducing the number of calls to the contact centre. Since the new bill has not been fully rolled out yet, Hydro One is unable to quantify the potential reductions.

f) Bills for demand and interval billed customers and generator statements have not been redesigned as part of this initiative. However customer feedback has identified numerous needs for improvement, including items such as enhanced on-line access to statements such as more detailed supporting data and calculations and statements that are more flexible to better reflect the site specific supply and billing parameter configurations.

g) Hydro One has shared the customer insights and bill design with the Electricity Distributors Association, numerous local distribution companies, and the Ministry of Energy as part of their initiative on updating existing bill format regulations. The Ministry of Energy is contemplating a working group to update bill format regulations in an effort to improve bill comprehension and satisfaction. It is anticipated that Ministry efforts will result in the need for other local distribution companies to make updates to their bill designs.

h) The majority of the funding outlined in the Investment Summary Document GP-29 is required to reengineer processes and replace antiquated tools and applications that support non-energy billing, including: invoicing, collections, and customer service such as providing customers electronic bills and self-service options. The remaining funds are earmarked for the implementation a new bill design to meet the needs of commercial and industrial customers.

Vulnerable Energy Consumers Coalition Interrogatory # 1

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

None

Interrogatory:

a) Please provide a table showing a summary by topic of customer concerns provided to Hydro One related to this application.

b) Please show how/where in the evidence the concern expressed is addressed

Response:

a) The OEB issued a summary of the OEB's Community Meetings on September 7, 2017 (see pages 12-14). For convenience, the summary of the issues and comments related to Hydro One's Application are provided below.

Issues and Comments Directly Related to Hydro One's Application

1.	The OEB should not approve this request by Hydro One to increase its rates. Reasons given included: • Hydro One should find efficiencies instead. • CEO and executive compensation should be reduced. • Replacement of assets should have already been paid for with revenues in the past (replacement reserve) and new funds are not necessary. Hydro One has been wasting money in the past. Rates in Ontario are the highest in the country creating hardships for customers and forcing business to close or relocate.
2.	The salaries of Hydro One's CEO, executives and employees are too high. The CEOs of BC and Quebec Hydro make one tenth of the amount the Hydro One CEO makes. There are too many vice presidents at Hydro One and too many employees were on the "sunshine list" when Hydro One was a part of it.
3.	Concerns over reliability and service capacity issues.
4.	Disagreement with customer assignments to density based rate classes. Customers who were classified as medium density by Hydro One for years have been reassigned to a low density classification with higher rates.

5.	In a few communities (particularly Leamington and Napanee), MPPs and some consumers said there was not enough advance notice about the community meetings. Several attendees said they heard about the meeting from their conservative MPP.
6.	Whether the OEB has ever refused a rate increase request and whether it is permitted to do so.
7.	Concerns that the OEB does not care about the customer/consumer (OEB accountability).
8.	An assertion that in the last Hydro One case, the OEB approved a higher increase than was requested.

Issues Directly Related to Hydro One's Application Specific to Certain Communities

1.	Leamington - Concerns were raised that greenhouse agricultural producers were moving investment and jobs to jurisdictions in the United States (Ohio, Pennsylvania) due to high electricity rates.
2.	Rockland – Concerns were raised about the need for additional capacity in the area, so that businesses could expand.
3.	Bracebridge - Customers were concerned about reliability and many had already purchased a backup generator; due to the number, frequency and duration of outages.

b) The OEB Community Days were held after Hydro One's Application was filed on March 31, 2016. Hydro One responded to the concerns raised in its Executive Presentation on December 7, 2017 in this proceeding (see transcript).

Vulnerable Energy Consumers Coalition Interrogatory # 2

Issue:
Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:
A-04-01 Page: 7

Interrogatory:
a) Does Hydro One's Ombudsman Office provide reports to the management of the Company?

b) If yes please provide the most recent report.

Response:
Please refer to Exhibit I-38-CCC-37.

Association of Major Power Consumers in Ontario Interrogatory # 53

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
Exhibit E: Calculation of Revenue Deficiency or Sufficiency

Interrogatory:
a) Please provide a schedule that sets out the key Capital & OM&A work program drivers of the Revenue Deficiency.

Response:
a) Please refer to Exhibit C2, Tab 1, Schedule 1 for OM&A Summary and Costs Drivers.

Please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 3.6 for Capital Expnenditures Summary.

For calculation of the updated revenue deficiency please refer to Exhibit I-3-CME-65.

Building Owners and Managers Association Toronto Interrogatory # 36

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01-02 Consolidated Business Plan

Interrogatory:

Please provide a copy of the company's business plan referred to in the first paragraph that was submitted to the HONI Board last April. Does the Company have replacement for its CFO? Please provide a status report.

Response:

The evidence cited does not state that a business plan was submitted to the Board of Directors in April 2017, as no such plan was submitted.

Hydro One has selected a new CFO, Paul Dobson, whose appointment will be effective March 1, 2018. Mr. Dobson was most recently CFO for Direct Energy Ltd. (Direct Energy), Houston, Texas, where he was responsible for overall financial leadership of a $15 billion revenue business with three million customers in Canada and the U.S. Since 2003, Mr. Dobson has held leadership positions in finance, operations and customer service across the Centrica Group, the parent company of Direct Energy.

Building Owners and Managers Association Toronto Interrogatory # 37

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01-02 Page: 2

Interrogatory:

Please explain in detail what is meant by "responsible stewardship of its transmission system". What is the class you are seeking to be the best of, Canadian utilities, North American utilities, or other?

Response:

In this context, “responsible stewardship of its transmission system” refers to Hydro One managing and operating the transmission system safely, reliably and cost effectively for its customers. Hydro One’s vision is to be a Canadian-based, leading North American utility.

Building Owners and Managers Association Toronto Interrogatory # 39

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Issue 41: Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs (excluding executive compensation)?

Reference:

Hydro One Consolidated Business Plan, December 2, Page: 4

Interrogatory:

a) Is the $11 million included in the table, or is it additional to the costs, eg. 2018 $312 million in the table?

b) Is there a more detailed treatment of corporate common costs? See, in particular, last paragraph. Please provide a detailed breakdown of each of the lines in the table on p4, with particular attention to the larger items, such as Planning, Customer and Corporate Relations, Network Operating. Please provide the appropriate ratio for each of the lines, and the most recent B&V study. Please provide the cost of the custom service to the DSP.

c) Has the Internal Audit completed its review of same or all of the eight recommendations? Please file once this is completed.

d) Please update the table and chart to September 30, 2017.

Response:

a) Yes the $11 million is included in the table.

b) Please refer to Exhibit C1, Schedule 1, Tab 7 for more details on Common Corporate Functions and Services, Exhibit C1, Tab 1, Schedule 8 for Planning, Exhibit C1, Tab 1, Schedule 9 for Information Technology ("IT") and Exhibit C1, Tab 1, Schedule 4 for Operations OM&A.

c) Referring to the Hydro One Consolidated Plan on page 4 provided in Exhibit A-3-1-2, there are no recommendations identified for Audit to review.

d) It's noted that this interrogatory requests Q3 information, however Hydro One intends to update this interrogatory and others requesting 2017 actuals when the 2017 actuals are available and believes this will fulfill the intent of the interrogatory.

Consumers Council of Canada Interrogatory # 2

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

Interrogatory:

Please provide all materials provided to HON's senior management, executives and to its Board of Directors when HON was seeking approval of the requests set out in the Application.

Response:

See response to Exhibit I-3-SEC-4.

Consumers Council of Canada Interrogatory # 3

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
None

Interrogatory:
Please describe, in detail, the overall planning process that HON undertook in developing its rate plan and in putting together its Application. Please include a complete timeline. Please provide all budget directives and guidance provided to employees.

Response:
The business planning process at Hydro One typically starts in the spring each year. Hydro One's planning group prepares the investment plan as described in section 2.1 of the DSP (Exhibit B1, Tab 1, Schedule 1) and then the common corporate costs are compiled and layered onto the investment plan. The result is run through Hydro One's business plan models to determine revenue requirement and average rate increases, and the written business plan documents are prepared and reviewed for presentation to Hydro One's Executive Leadership Team followed by its Board of Directors. The Dx Business Plan forms the basis for this Application. Supporting evidence for the Application is prepared based on the approved business plan.

Please see Exhibit I-24-SEC-36 for a timeline for the process.

Please see Exhibit I-3-SEC-1 for budget guidance documents.

Consumers Council of Canada Interrogatory # 4

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

Interrogatory:

Please explain, how the acquisition of Avista Corporation could potentially impact HON's Distribution costs over the term of the plan. Have any studies been produced assessing the potential impacts? If so, please provide copies of those studies.

Response:

Please refer to Exhibit I-21-SEC-32.

Consumers Council of Canada Interrogatory # 5

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01 Page 3

Interrogatory:

Please provide a copy of the 2018-2022 Distribution Business Plan referred to on p. 3 (Attachment 1 is the 2017-2022 Distribution Business Plan). Please provide a copy of the most recent Transmission Business Plan. When is the next Distribution Business Plan to be completed?

Response:

The 2018-2022 Distribution Business Plan referred to on page 3 is the same as the 2017-2022 Distribution Business Plan provided as Attachment 1. The most recent Transmission Business Plan is out of scope for this proceeding. The elements common to Hydro One's transmission and distribution businesses are covered in the Consolidated Business Plan 2017-2022 provided as Attachment 2 to Exhibit A, Tab 3, Schedule 1 and in Attachment 1 to Exhibit I-26-VECC-23.

The next Distribution Business Plan will be prepared as part of Hydro One's next business planning cycle in 2018.

Consumers Council of Canada Interrogatory # 6

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01 Page 36

Interrogatory:

The evidence sets out the Total Bill Impacts by rate class. Please provide a schedule setting out the Total Bill impacts assuming the application of the Fair Hydro Plan. Please explain, in detail, the process HON undertook to apply the elements of the Fair Hydro plan in arriving at the bill impacts. Please provide a sample residential bill that has been derived by applying the Fair Hydro Plan.

Response:

Please see the response to Exhibit I-4-PWU-4.

A sample residential bill that has been derived by applying the Fair Hydro Plan is provided as an Attachment to this response.

SEC/101
1/29/18 11:47:18 AM
TOU:X Dial:
OOB:

MR JOHN DOE
Your account number is: **1234 5612 3456**
This statement is issued on: **January 9, 2018**

Filed: 2018-02-12
EB-2017-0049
Exhibit I-3-CCC-6
Attachment 1
Page 1 of 2

Your Electricity Statement

For the period of: **December 1, 2017 - January 4, 2018**

What do I owe?

$122.18

See reverse for a summary of your charges

How much did I use?

You powered your home with

750 kWh

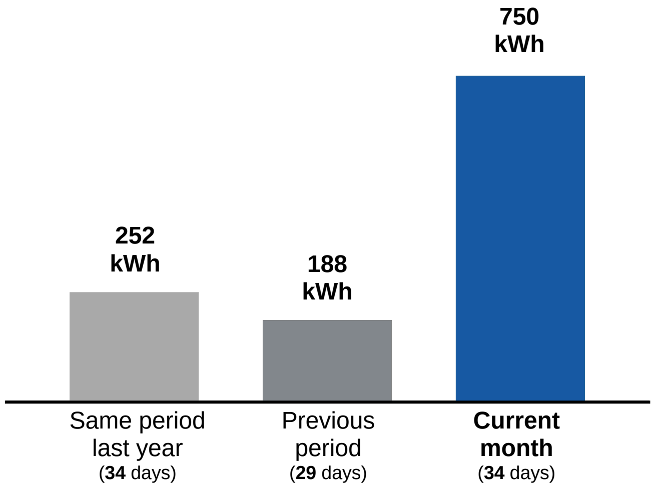
of electricity this period

When is it due?

Jan 28, 2018

What does my electricity usage look like?

Find out more by logging into ***my*Account** at www.HydroOne.com



What do I need to know?

Ontario's Fair Hydro Plan saved you $58.39 on your bill. This amount includes the 8% Provincial Rebate.

For billing, quick answers and much more, visit **www.HydroOne.com**

For emergencies or reporting outages **1-800-434-1235** (24 hrs)

For service inquiries and payment **1-888-664-9376** Mon to Fri 7:30 a.m. - 8 p.m.

Hydro One Networks Inc.
PO Box 5700
Markham, ON L3R 1C8

Please return this slip with your payment.

Your account number: **1234 5612 3456**

Total amount you owe **$122.18**

Amount enclosed $

MR JOHN DOE
123 MAIN ST
SOMETOWN ON X0X 0X0

HYDRO ONE NETWORKS INC.
PO BOX 4102 STN A
TORONTO ON M5W 3L3

123456123456000122185

What am I paying for?

Balance carried forward from previous statement		**$0.00**
Amount from your previous period	$60.71	
Amount we received on Dec 26/17	−$60.71	
Your electricity charges		**$122.18**
Total amount you owe		**$122.18**

If payment is not received by Jan 28, 2018, a late payment charge of 1.5% compounded monthly (19.56% per year) will be calculated from the statement date and applied to your account.

Powering 123 MAIN ST

Point of Delivery: 11111111 — **Residential - Medium Density**

Electricity $61.51

This is the cost of generating the electricity you used this period. Usage is measured in kilowatt-hours (kWh) and depends on the wattage of devices you use and how long you use them. The Ontario Energy Board (OEB) sets the cost per kWh and the **money collected goes directly to the electricity generators**.

Delivery $51.45

This is the cost of ensuring you have reliable power when you need it. **Hydro One collects this money** to build, maintain and operate the electricity infrastructure, which includes power lines, steel towers and wood poles covering 960,000 sq. km. A portion of this cost is fixed and a portion varies depending on the amount of electricity used.

Regulatory Charges $3.40

The Independent Electricity System Operator (IESO) uses this money to manage electricity supply and demand in the province, which is necessary to ensure that there is enough electricity to meet Ontario's needs at all times.

HST (87086-5821-RT0001) $15.13

8% Provincial Rebate .... −$9.31

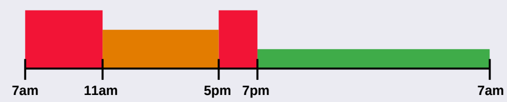
Total of your electricity charges **$122.18**

What is my Time-of-Use breakdown?

Dec 1/17 to Jan 4/18	Usage (kWh)	Rate (¢)	Amount
On-Peak	140.102	13.2	$18.49
Mid-Peak	112.2738	9.5	$10.67
Off-Peak	497.6243	6.5	$32.35

My current Time-of-Use schedule

Winter: Weekdays - Nov 1 to Apr 30

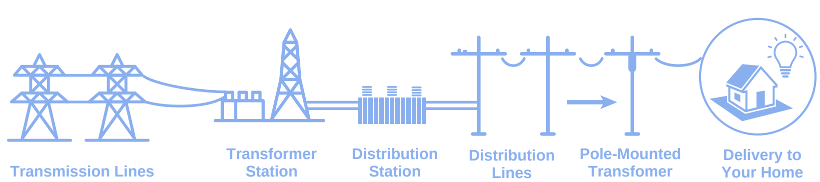


Weekends & holidays are always Off-Peak

Meter Number	Current Reading	Previous Reading	Difference	Usage in kWh
J1234567	Jan 4/18 12404.0568	Dec 1/17 11654.0568	750.0	(x1) = 750.0

Hydro One - How the System Works

Hydro One's role is to make sure that Ontario's electricity can flow directly to you, our customers, through our system safely and reliably.



Energy Saving Tip

Phantom Power

Electronics use energy even when off. Plug them into power bars with timers or auto-shutoff to lower energy use.

Consumers Council of Canada Interrogatory # 7

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
A-03-01-01

Interrogatory:
The 2017-2022 Business Plan is dated December 2, 2016. Please provide a timeline setting out the steps that led to this final Business Plan. How describe how HON operates in the context of two separate business plans given many of the resources are shared between Transmission and Distribution (e.g.; work force, Common Corporate Costs)?

Response:
Please refer to Exhibit I-24-SEC-36 for the timeline.

Hydro One prepares business plans for its transmission and distribution businesses simultaneously, focusing on their specific business requirements. As far as operating with shared resources, work is planned for each business to balance the workforce available with the planned work. Similarly, the groups that perform common corporate functions and services are staffed appropriately to balance their work requirements between the businesses.

Consumers Council of Canada Interrogatory # 8

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-02 Page 8 Table 3

Interrogatory:

Based on the proposed revenue requirement figures set out in Table 3 please confirm that HON is seeking to recover (on average) approximately an additional $52 million per year from its customers over the plan term relative to current rates. Please provide the total amount per year (increases relative to current rates) inclusive of the deferral and variance account amounts.

Response:

As outlined in the table below, Hydro One is seeking to recover (on average) an additional $50.7 million per year from its customers over the plan term relative to current rates inclusive of deferral and variance account amounts. Hydro One notes that the appropriate proposed revenue requirement figures for this calculation are provided in the application update filed in Exhibit Q, Tab 1, Schedule 1.

Year	Revenue Requirement (A) **	DVA Disposition (B) ***	Total (C = A+B)	Change in Total (C) Relative to Prior Year
2017	$ 1,467.58	$ 11.08	$ 1,478.66	-
2018	$ 1,517.11	$ 6.18	$ 1,523.29	$ 44.63
2019	$ 1,564.06	$ 6.18	$ 1,570.24	$ 46.95
2020	$ 1,610.67	$ 6.18	$ 1,616.85	$ 46.60
2021	$ 1,684.41	$ 6.18	$ 1,690.59	$ 73.75
2022	$ 1,725.87	$ 6.18	$ 1,732.05	$ 41.46
			Average Annual Change	$ 50.68

* All dollar figures are in millions.
** Revenue requirements reflect values in Exhibit Q, Tab 1, Schedule 1.
*** DVA refers to deferral and variance account balances for disposition.

Consumers Council of Canada Interrogatory # 9

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01

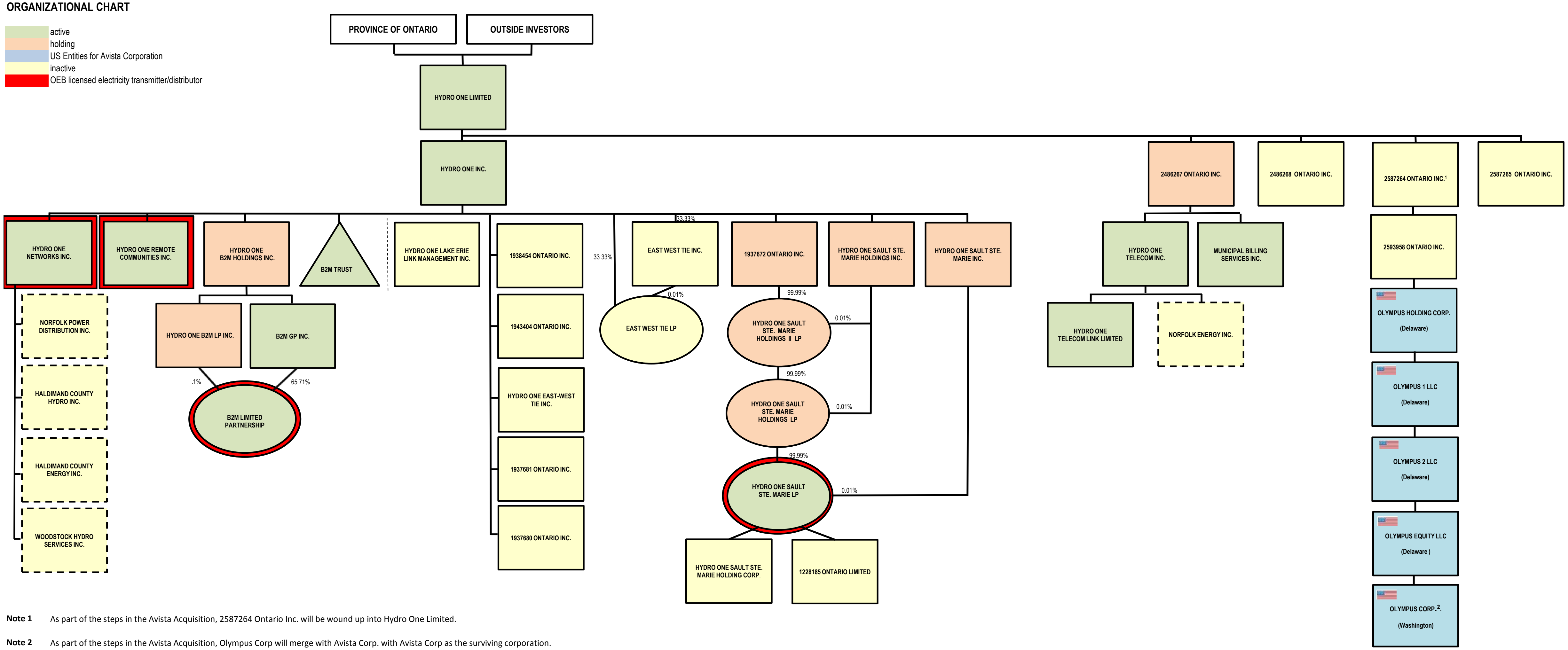
Interrogatory:

HON has provided a Corporate Organization Chart as it relates to HON Distribution. Please provide a complete corporate organization chart that includes all legal entities within HON Limited's organizational structure. In addition, please provide a complete organization chart for Hydro One Networks Inc. that includes both HON Transmission and Distribution (Please include employees down to the Director Level).

Response:

Please see Attachment 1 which reflects the corporate organizational structure. Please see Exhibit I-3-SEC-5 for the organizational chart for Hydro One Networks.

HYDRO ONE
ORGANIZATIONAL CHART



Note 1 As part of the steps in the Avista Acquisition, 2587264 Ontario Inc. will be wound up into Hydro One Limited.

Note 2 As part of the steps in the Avista Acquisition, Olympus Corp will merge with Avista Corp. with Avista Corp as the surviving corporation.

Canadian Manufacturers & Exporters Interrogatory # 42

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-02-05 Updated
C1-07-02-06 Updated

Interrogatory:

A comparison of the number of eligible positions in 2016 (Attachment 6) and the forecast for 2018 through 2022 (Attachment 5) shows significant reductions for the Ontario Co-op Education Credit (358 to 247), the Ontario Apprenticeship Credit (394 to 346 in 2018 and to 268 in subsequent years) and the Federal Apprenticeship Tax Credit (245 to 169).

a) Please explain the significant reduction in the eligible positions for each of the above noted tax credits.

b) Please confirm that the wages & salaries included in OM&A costs for the 2018 through 2022 period reflect the reduction in eligible positions.

c) Please explain why the average annual Ontario Apprenticeship Credit per eligible position is about $3,000 per year when the credit is $5,000 per year.

Response:

a) The 2016 Ontario Co-op Education, Ontario Apprenticeship and the Federal Apprenticeship credits (the "Tax Credits") in Exhibit C1-7-2, Attachment 6 were estimates as the 2016 Hydro One Networks Inc. tax return was not filed at the time when the 2016 Tax Credits were compiled. These Tax Credits were subsequently trued up to actual amounts on the 2016 tax return as follows:

Summary of Tax Credits ($ Thousands)			
	2016 (1)	**2018 (2)**	**2019 (2)**
Ontario Coop Education Credit	$ 760	$ 740	$ 740
Eligible Positions	254	247	247
Ontario Apprenticeship Credit	$ 2,644	$ 1,430	$ 860
Eligible Positions	385	346	268
Federal Apprenticeship Credit	$ 323	$ 320	$ 320
Eligible Positions	171	169	169

(1) Per 2016 Hydro One Networks Inc. tax return
(2) Per Exhibit C1-07-02, Attachment 5

As illustrated above, the actual eligible positions for Ontario Co-op Education Credit and Federal Apprenticeship Credit in 2016 are consistent with those reported for the test years in Exhibit C1-07-02, Attachment 5.

The number of eligible positions for Ontario Apprenticeship Credit was decreased mainly due to an Ontario legislative change, which reduced the eligible period for Ontario Apprenticeship Credit by 12 months, from the first 48-month of the apprenticeship program to the first 36-month for apprenticeship programs commencing after April 23, 2015. As summarized below, the group of employees in 2016 that qualify for Ontario Apprenticeship Credit is larger than in future years such as 2019 onwards.

Summary of Ontario Apprenticeship Positions

Fiscal Years	Eligible Positions	Period	Approx. Yrs
~~2016~~	385	2013 to 2016	4 Years
2018	346	January 1, 2015 to April 23, 2015 2016 to 2018	< 4 years
2019 +	268	2017-2019	3 Years

b) As discussed in (a), eligible positions for the Ontario Co-op Education Credit and the Federal Apprenticeship Credit for the test years were consistent with the 2016 tax return. The number of eligible positions that qualified for the Ontario Apprenticeship Credit declined due to a change in the Ontario legislation and not the number of eligible apprentices employed by Hydro One.

c) The maximum annual Ontario Apprenticeship Credit is $5,000 per year. However, Hydro One estimated average annual Ontario Apprenticeship Credit to be $3,000 to reflect apprentices enrolled in an eligible program for part of the year.

Canadian Manufacturers & Exporters Interrogatory # 46

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-01
EB-2016-0160 Decision and Order dated November 9, 2017

Interrogatory:

a) What is the impact on the 2018 distribution revenue requirement if Hydro One were to quantify and reflect the OEB findings in the November 9, 2017 EB-2016-0160 Decision and Order related to the regulatory income taxes recoverable from ratepayers.

Response:

In the November 9, 2017 EB-2016-0160 Decision and Order, OEB ordered Hydro One to give ratepayers an allocation of the future tax savings based on benefits follow costs "Actual FMV Sales and Payments" allocation factor that was established in the September 28, 2017 EB-2016-0160 Decision and Order ("September Decision"). As of January 1, 2018, 47.4% of the Province shares in Hydro One Limited ("HOL") were sold, and another 2.4% of the Province shares in HOL were sold to First Nations on January 4, 2018, for a total of 49.8% of HOL shares that were owned by new shareholders. Using the same methodology as illustrated in the September Decision, the benefits follow costs allocation ratio in favour of shareholders for Distribution is estimated to be 61.6% and is calculated as follows:

Actual FMV Sales and Payment Ratios - Distribution

	49.8% Shares Sold		
Actual Payment Proportions toward FMV bump			
- By new shareholders (47.4% + 2.4% First Nation)	49.8%	4,171.0	2,077
- Departure tax on remainder	50.2%	984.0	494
			2,571
		$2,571/$4,171 =	61.6%

Based on this updated ratio, the revised regulatory income taxes for 2018 would be reduced from $65.4 million as reported in Exhibit Q, Tab 1, Schedule 1 to $40.3 million.

This was noted in Procedural Order No. 2 of this proceeding which stated:

> “The OEB understands that Hydro One’s proposed treatment of tax savings resulting from the Government of Ontario’s decision to sell its ownership interest in Hydro One Limited by way of an IPO and subsequent sale of shares in this Distribution Rates Application is consistent with its proposed approach to those savings in the Transmission application. That is, Hydro One does not intend to apply any tax savings resulting from the IPO to reduce Hydro One’s distribution revenue requirement. As Hydro One notes “Neither the departure tax nor the change in tax regime will have any impact on ratepayers. For regulatory purposes, income tax expenses will continue to be calculated according to the method prescribed by the Board’s 2006 EDR Tax Model and 2006 EDR Handbook, Section 7.1 “OEB 2006 Regulatory Taxes Expense Methodology”[1]. The OEB does not intend to have that matter re-litigated in the current proceeding while the motion and appeal are pending. Accordingly, the OEB will not permit the Tax Savings Determination issue to be addressed in the distribution case, pending the outcomes of the Hydro One Motion and Appeal.” (Decision on Issues List, Interim Rates and Procedural Order No. 2, December 1, 2017, page 3-4)

Canadian Manufacturers & Exporters Interrogatory # 65

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

E1-01-01 Updated

Interrogatory:

a) Please update all of the tables in Schedule 1, along with the Revenue Requirement Workform, to reflect any changes made as a result of the responses to the interrogatory responses, and/or any updates or revisions made prior to the filing of the interrogatory responses.

Response:

a) Please refer to Exhibit I-33-Staff-179 for updated tables.

The Revenue Requirement Workform is filed as MS Excel I-03-CME-65-01.

Energy Probe Research Foundation Interrogatory # 2

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

E1-01-02 Page: 2 Table 1

Interrogatory:

Please explain the large variance in Regulated Revenues between 2016 Actual and 2016 Approved.

Response:

The large variance in the Regulated Revenues is due to the Decision and Order in EB-2015-0141 (Rogers Communication Partnership et al.). In late 2016, the OEB issued the decision which determined Hydro One's Joint Use telecom rate for calendar years 2015-2017. In this decision, the OEB approved a rate of $41.28 per attacher, per pole.

In late 2016, Hydro One back billed for the difference of the interim rate, and the approved rate for 2015 and 2016, which equated to $10.4M. The majority of the 2016 variance is due to the increase in Joint Use Revenues.

Witness: BOLDT John

Power Workers' Union Interrogatory # 1

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Issue 5: Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?

Reference:

N/A

Interrogatory:

a) Which Hydro One rate classes benefit from bill protection pursuant to the terms of the Fair Hydro Plan (FHP)?

b) In 2016, how many customers were in each of these rate classes?

c) What percentage of Hydro One's total customers in 2016, do these customers represent?

d) In 2016, how much distribution revenue did Hydro One receive from these customers?

e) In 2016, what percentage of Hydro One's total distribution revenue was received from these customers?

Response:

a) Hydro One's R1 and R2 customers specifically benefit from the Distribution Rate Protection Program as set out in the Fair Hydro Plan.

   Hydro One notes that there are certain aspects of the Fair Hydro Plan that benefit customers of all distributors in Ontario, including: i) reduced Global Adjustment charges and the Ontario Rebate for Electricity Consumers ("OREC") credits for residential and low volume general service customers, ii) reduced regulatory charges (OESP charge eliminated, RRRP charge reduced) and iii) lower eligibility threshold for the Industrial Conservation Initiative ("ICI") program so more large general service customers can participate.

b) In 2016, there were 441,836 R1 customers and 328,766 R2 customers.

c) In 2016, in terms of number of customers, R1 represented 34% of total and R2 represented 26% of total. Former Norfolk, Haldimand and Woodstock customers were not included in this analysis as these customers had not been integrated into Hydro One's rate structure.

d) In 2016, Hydro One received $295.7 million and $476.2 million (including the RRRP credit) in base distribution revenue from R1 and R2 classes, respectively.

e) In 2016, in terms of base distribution revenue, R1 represented 22% of total and R2 represented 35% of total. Former Norfolk, Haldimand and Woodstock customers were not included in this analysis as these customers had not been integrated into Hydro One's rate structure.

School Energy Coalition Interrogatory # 1

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

Interrogatory:

Please provide a copy of all budget guidance documents that were issued regarding the 2018-2022 budgets that underlie the application.

Response:

Please see the attached budget guidance documents.

Attachment 1 – Common Corporate Costs Validation Kick-off 2017-2022 (June 15/16, 2016)
Attachment 2 – Regulatory Expectations for the Dx Filing (June 2, 2016)
Attachment 3 – Kick-off Investment Planning Process 2017-2022 (June 2, 2016)
Attachment 4 – Investment Planning Training 2017-2022 (Winter 2016)

Common Corporate Costs Validation Kick-off

2017 - 2022

June 15/16, 2016

Key Points of Discussion

- Key Points for Investment Plan Instructions
- Key Regulatory Points
- Common Corporate Costs Validation approach
- Schedule

Constraints are in place to guide Investment Plan Development

Constraints/Considerations	
Financial	Asset need, 4.2% rate base growth, productivity, and inflation
Regulatory	OM&A follow the OEB decision for 2017, and then for 2018-2022 assume IRM rate regime (inflation less productivity)
Forecast	Exception updates only
Schedule	Strict adherence to deadlines within IPP to meet established milestones
Common	Costs held in 2017 & 2018 due to Tx Rate Filing; approved changes must neutral or a “blue page update”
Resources	Work Program Levels must be achievable

Expectations: Regulatory

Hydro One's previous RRFE Distribution rate application not accepted by OEB in March 2015

At highest level, application not accepted due to insufficient alignment with RRFE

- However, 2015-2017 rates were accepted on a Cost of Service basis

Several specific reasons cited:

- Inconsistency with outcome-based regulation
- Lack of externally imposed incentives to inform productivity and efficiency gains
- Weak benchmarking evidence
- Limited prospects for continuous improvement
- Unclear demonstration of value to customers

In addition, OEB highlighted ten specific studies to complete and address in subsequent filing

- Largely focused on productivity and benchmarking

Key steps being taken to address areas of concern in upcoming Distribution application

Incorporate incentive rate structure to drive RRFE's desired performance outcomes

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

Heavily leverage customer engagement findings to inform Distribution System Plan

- Customer need and preferences to drive investments

Reflect thorough internal and external benchmarking to support:

- Levels of planned spend
- Opportunities for improvement / efficiency

Include an Earnings Sharing Mechanism to align financial incentives with customers

Remove complexity wherever possible

Expectations: Regulatory

hydro one

5-year Distribution filing will fall under an incentive rate mechanism…

Three available incentive rate mechanisms:

- **Annual index -** rate increases limited to inflation less a productivity improvement factor
- **Price Cap –** similar to annual index, with tools for recovery of capital from unforeseen events
- **Custom –** applicant must define a custom formula to capture 5-year capital and OM&A needs

Selection of mechanism to be based on balancing flexibility (required to meet Hydro One's needs) with complexity (which drives regulatory risk)

Several features common to all 3 mechanisms:

- Comprehensive coverage (capital and OM&A)
- Productivity – capital and OM&A
- Sharing of benefits – earnings sharing mechanism
- Off-ramps for certain unforeseen events
- Variance and deferral accounts – including capital in-service variance account
- Performance reporting and monitoring

…necessitating an increased focus by Hydro One on three areas

1. **Living within our means – staying within capital envelope**
2. **Improving rigour in planning and execution – need to ensure we "get it right"**
3. **Becoming more efficient – driving and measuring productivity across lines of business**

Common Corporate Costs Validation

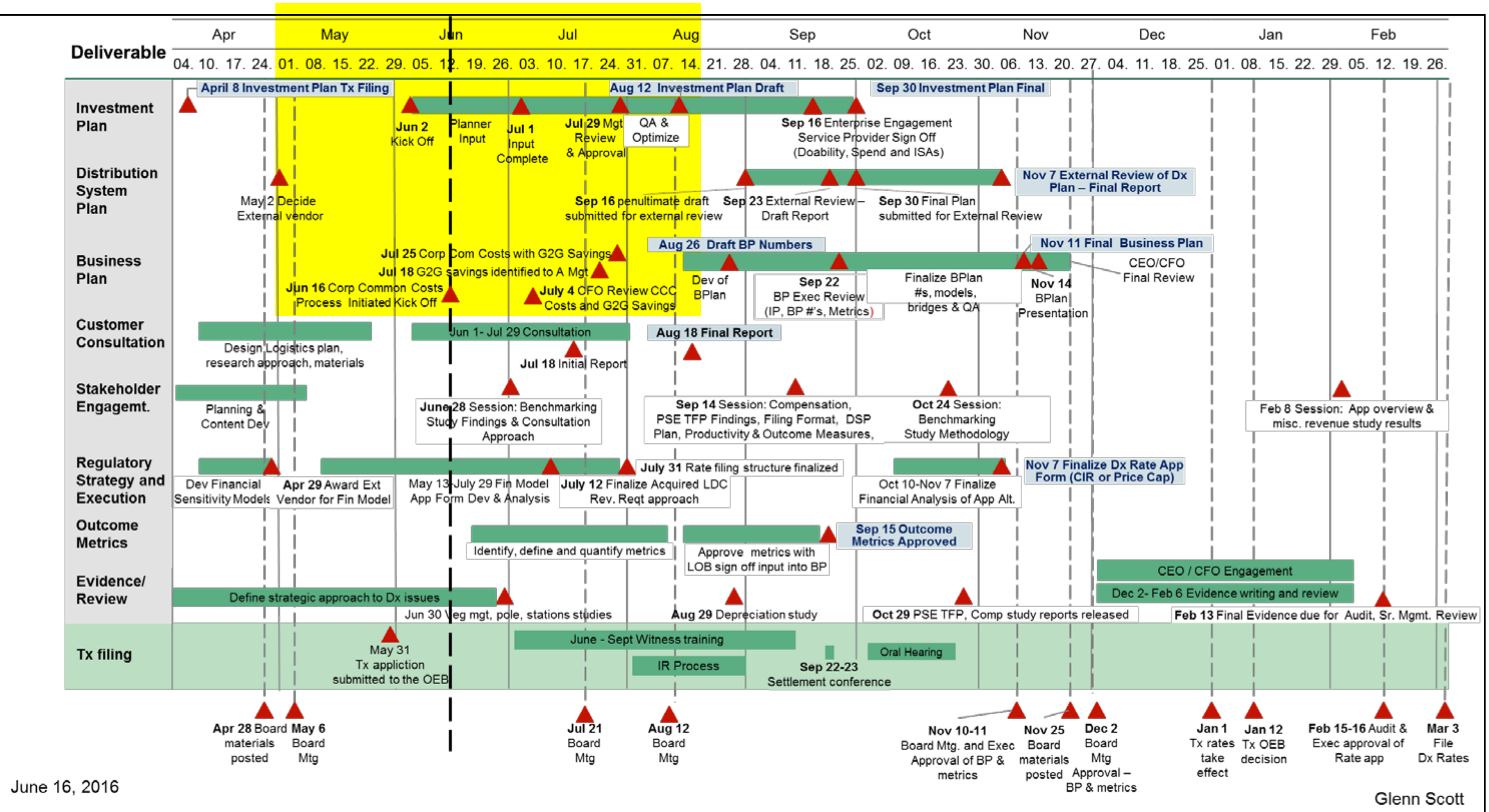
- Good to Great productivity opportunities identified in numerous groups
- Manifest in staffing reductions in some CCC groups
- Staff level baselined as of January 15, 2016.
- Reductions from there identified.

NOTE: Savings identified in 2016 are expected to carry forward year over year

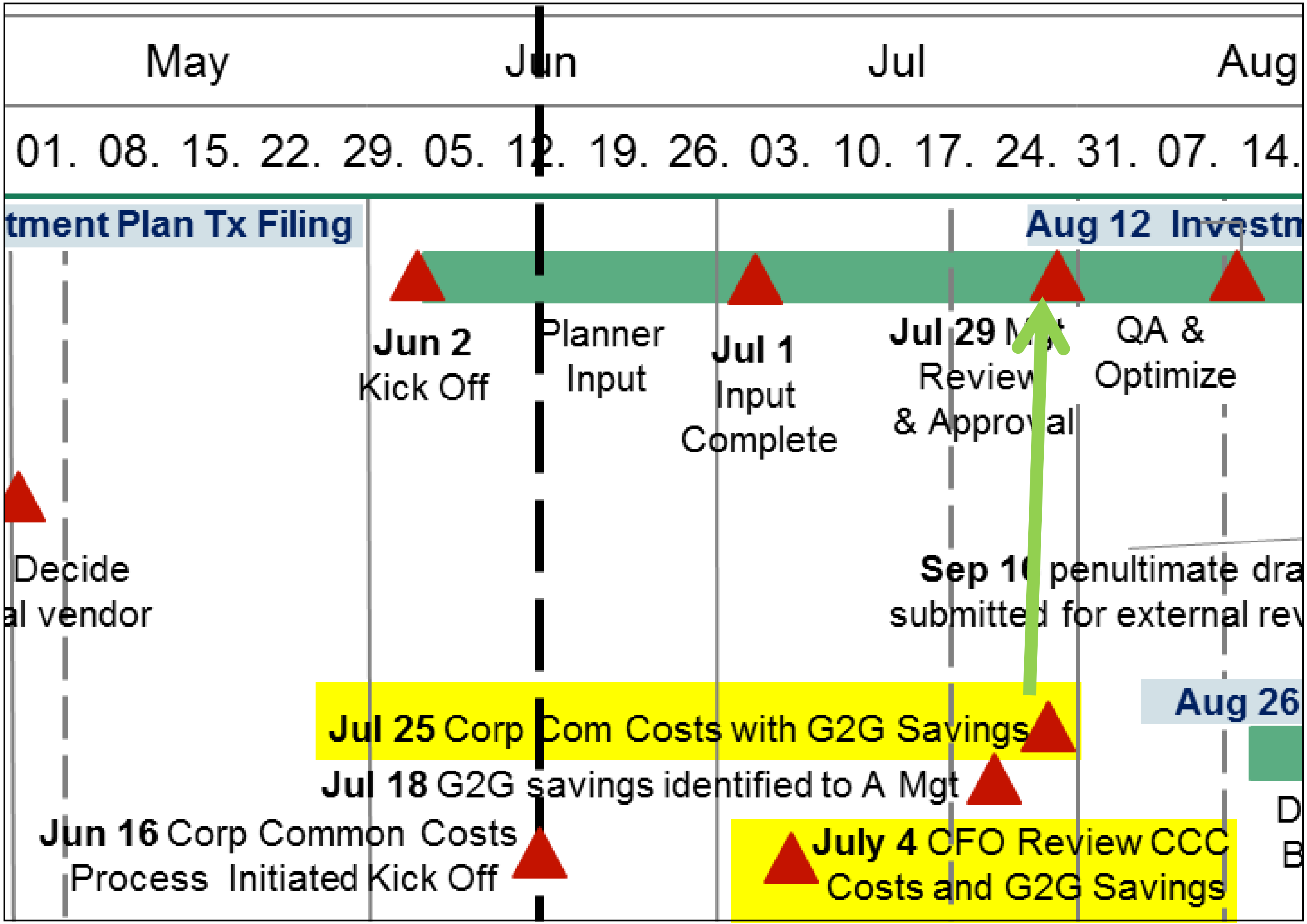
Common Corporate Costs Validation

- Information for you to review for your Cost Centers:
  - January 15, 2016 staff level
  - Agreed to BCG number
  - Current staff level
- Follow up next week with revised Green Sheets based on agreed to BCG numbers
  - Need to update non-labour costs based on new staff numbers

Timeline for activities leading up to Dx rate filing



Key Dates for Common Corporate Costs
July 4 and 25



Common Corporate Costs Validation

- Any increases offset by decrease elsewhere.
- Focus on BCG agreed to staff levels
- Revise non-Labour costs in Green Sheets

- July 4 CFO review (info to Scot by June 29 for Mike pre-read)
- July 25 Final numbers into AIP (info to Scot by July 20)

Regulatory Expectations for the Dx Filing
June 2, 2016

Expectations: Regulatory

Hydro One's previous RRFE Distribution rate application not accepted by OEB in March 2015

At highest level, application not accepted due to insufficient alignment with RRFE

- However, 2015-2017 rates were accepted on a Cost of Service basis

Several specific reasons cited:

- Inconsistency with outcome-based regulation
- Lack of externally imposed incentives to inform productivity and efficiency gains
- Weak benchmarking evidence
- Limited prospects for continuous improvement
- Unclear demonstration of value to customers

In addition, OEB highlighted ten specific studies to complete and address in subsequent filing

- Largely focused on productivity and benchmarking

Key steps being taken to address areas of concern in upcoming Distribution application

Incorporate incentive rate structure to drive RRFE's desired performance outcomes

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

Heavily leverage customer engagement findings to inform Distribution System Plan

- Customer need and preferences to drive investments

Reflect thorough internal and external benchmarking to support:

- Levels of planned spend
- Opportunities for improvement / efficiency

Include an Earnings Sharing Mechanism to align financial incentives with customers

Remove complexity wherever possible

Expectations: Regulatory

5-year Distribution filing will fall under an incentive rate mechanism…

Three available incentive rate mechanisms:

- **Annual index -** rate increases limited to inflation less a productivity improvement factor
- **Price Cap –** similar to annual index, with tools for recovery of capital from unforeseen events
- **Custom –** applicant must define a custom formula to capture 5-year capital and OM&A needs

Selection of mechanism to be based on balancing flexibility (required to meet Hydro One's needs) with complexity (which drives regulatory risk)

Several features common to all 3 mechanisms:

- Comprehensive coverage (capital and OM&A)
- Productivity – capital and OM&A
- Sharing of benefits – earnings sharing mechanism
- Off-ramps for certain unforeseen events
- Variance and deferral accounts – including capital in-service variance account
- Performance reporting and monitoring

…necessitating an increased focus by Hydro One on three areas

1. **Living within our means – staying within capital envelope**
2. **Improving rigour in planning and execution – need to ensure we "get it right"**
3. **Becoming more efficient – driving and measuring productivity across lines of business**

Expectations: Regulatory

OEB's expectations regarding Hydro One's Distribution System Plan (DSP) are set out in the Board's Filing Requirements. Meeting these requirements is mandatory.

OEB's evaluation of the DSP is focused on outcomes and will consider the following:

- Responsiveness to customer needs and preferences;
- Value proposition for customers in terms of economic efficiency and cost-effectiveness;
- Integrated/regional planning/alternatives;
- Operational effectiveness – continuous improvements in productivity and cost performance while delivering explicitly stated system reliability and quality objectives;
- How the DSP has been integrated and rationalized to enable timely and appropriate expenditures in relation to government-mandated obligations; and
- Financial viability and operational effectiveness – sustainability of efficiencies in OM&A and capital (planning and execution).

DSP must also address OEB's comments in March 12, 2015 Decision relating to 2015 to 2017 distribution rates.

Regulatory Affairs will provide considerations relevant for the preparation and documentation of proposed distribution investments in a follow-on meeting.

Expectations: Regulatory

Integrated Organizational Effort

Draft – for discussion purposes only

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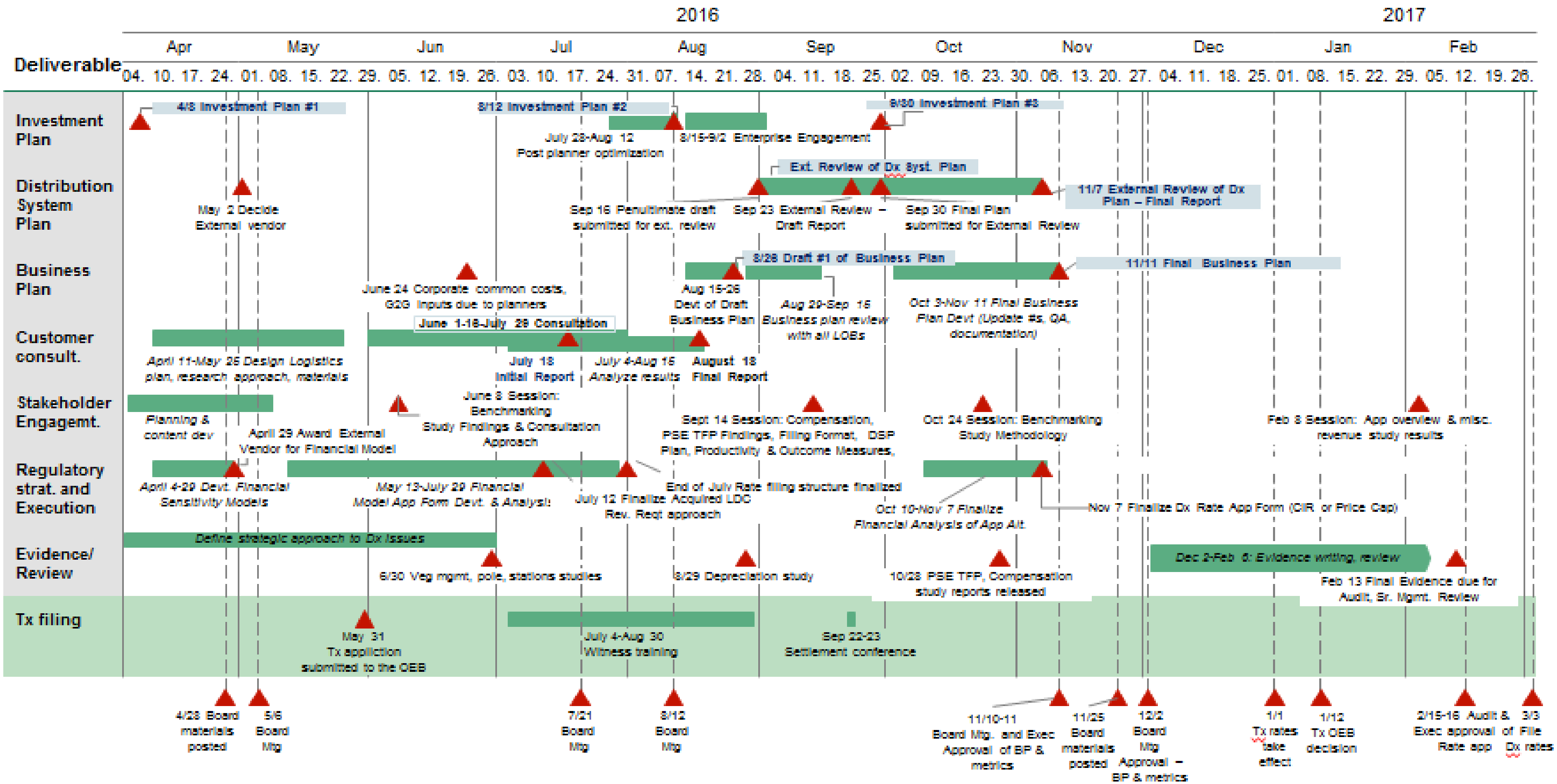
Timeline for activities leading up to Dx rate filing



Summary of Key Expectations

- Where the regulatory environment is subject to uncertainty (eg cost responsibility and contribution level to SECTR/Leamington, or policy risk if non-recover of certain costs, consult with Reg Affairs and highlight the risk

Kick-off
Investment Planning Process

2017 - 2022

June 2, 2016

Key Points of Discussion

- Cycle is for Distribution Investments
  - Objectives
  - Constraints
- Creating an Optimized Plan
- Investment Plan Review
- Schedule

Prioritized IPP Pain Points to be Addressed this cycle:

Pain points prioritized by criticality and ease of addressing

1 Lack of clarity of financial boundary conditions

2 Spend categories not linked to outcome-driven objectives

3 Business values/weights do not reflect current corporate strategy

4 Planners/managers do not understand optimization process

5 Lack of feedback received on input to IPP process

6 Planner inputs are of inconsistent quality

7 Insufficient time for investment definitions + quality check

8 Inaccuracy / lack of cost-estimates for potent. investments

9 Risk evaluation process is not consistently applied

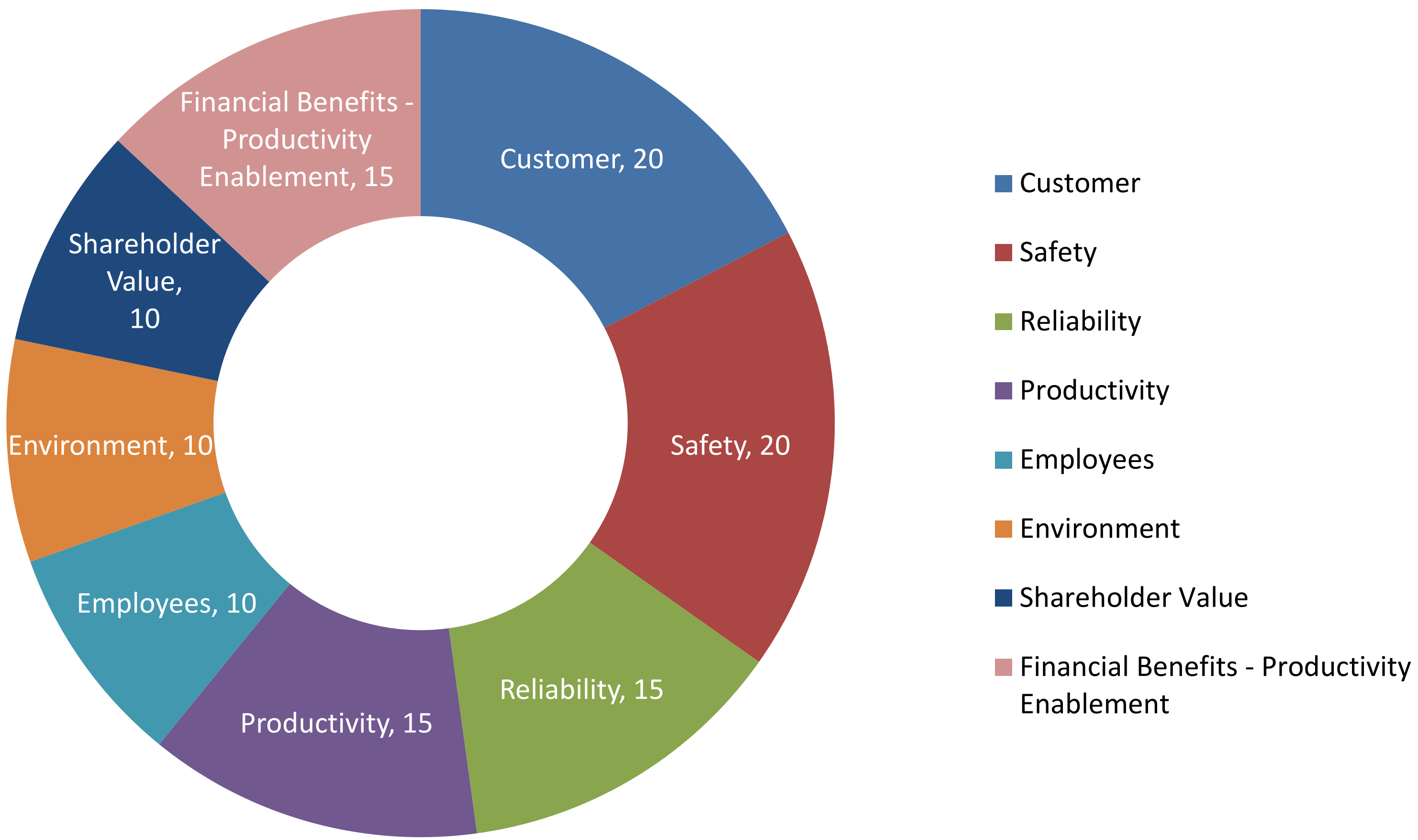
10 Invest. not tracked against expected perform. outcomes

"Quick wins" **Intermediate targets** **Long-term efforts**

Planning Cycle to establish an Optimized Plan for Dx Rate Filing

Objective
Finalize Dx CapEx & OMA Components of the 2017-2022 Investment Plan….
Validate & Document Investment Risk Assessment
Calibrate Risk Assessment across Business Units
Align Investment Strategy to Customer Consultations
Incorporate Feedback as a result of OEB Mandated 3rd Party Review
Develop efficiencies based on outcome of Productivity Studies
Ensure Alignment between Planning and Operations
To establish an Optimized Plan for Dx Rate Filing in Spring 2017

No Change to the Current Business Objectives and Weightings is Assumed



Note: individual weightings are determined through the allocation of 115 total value points

Constraints are in place to guide Investment Plan Development

Constraints/Considerations	
Financial	Asset need, 4.2% rate base growth, productivity, and inflation
Regulatory	OM&A follow the OEB decision for 2017, and then for 2018-2022 assume IRM rate regime (inflation less productivity)
Forecast	Exception updates only
Schedule	Strict adherence to deadlines within IPP to meet established milestones
Common	Costs held in 2017 & 2018 due to Tx Rate Filing; approved changes must neutral or a “blue page update”
Resources	Work Program Levels must be achievable

Investment Plan will be formed by multiple inputs and result in changes throughout the planning process

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Requirements	
Pricing	Agreement on costing between Planning & Operations; *Unit Prices will need to be updated with any G2G productivity savings.*
Investment Categorization	Identification of investments as Foundational vs Enhancement work; Reporting Framework for Rate Filing
Risk Calibration Session	Check that investment levels are appropriate and risk is consistently applied across all business units
Customer Consultation	Feedback to drive enhancement work; to be incorporated as information becomes available – during Manager/Director sign-off (late July).
3rd Party Review	Regulatory review of Dx Investment Plan to benchmark against other utilities
Productivity Studies	Outcome to be determined in summer with efficiencies to be included as deemed appropriate
Multi-Stage Review	Investments to undergo detailed review pre-optimization to eliminate tedious post-optimization changes; Post-optimization portfolio review to ensure cross-functional alignment

Investments segmented into foundational and enhancement categories with different purposes

	Investment category	Purpose
	Note: Will also consider applicability to Tx	
1 Foundational	a Asset renewal / maintenance b Customer connections c Safety, security, enviro (compliance) d Customer projects (ongoing) e Outage response f Facilities g Enterprise IT	**Maintain current reliability risk and system performance** • Continue to prioritize based on existing risk model / investment planning process
2 Enhancement	a Reliability enhancement b Grid mod (comms / automation) c Advanced analytics d Distributed Energy Resources enablement e Additional capacity / reserves f Grid hardening	**Enhance performance and deliver outcomes desired by customers**

Outcome	Metric
Improved reliability	$ / ACI
Reduced O&M	Annual savings / $ invested
Avoided CapEx	20-year NPV
Cust. energy efficiency / conservation	Load reduction / $ invested
New cust. products / services	Qualitative assessment

Customer input will help determine enhancement outcomes to prioritize in investment plan

1. Note: Foundational investments are those that are required for Hydro One to continue to deliver safe, reliable, and efficient service to all customers

Investment Plan will be formed by multiple inputs and result in changes throughout the planning process

Requirements	
Pricing	Agreement on costing between Planning & Operations; *Unit Prices will need to be updated with any G2G productivity savings.*
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Risk mitigation is a **consistent standard** used to value investments, and is used to **facilitate trade-offs between investments**

Risk Assessment Process

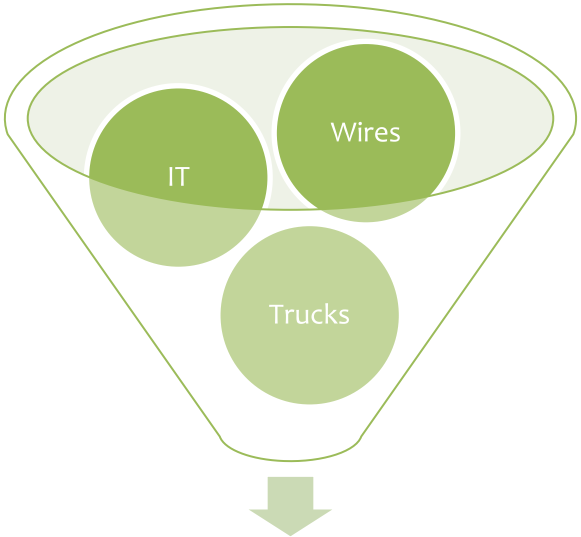
- For each identified investment need, risk is assessed against the potential impact on the Company's Business Values; investment alternatives are developed which may reduce the probability (risk abatement) and/or the consequence (risk mitigation) of the risk occurrence.
- **The risk assessment process allows investments to be compared** to one another on a value basis **across different portfolios**.

Investment Optimization Process

- The Investment Optimization process considers different investment increments/timing comprised of different risk management alternatives to facilitate tradeoffs between risk, cost and performance.
- The result is an investment plan that manages risk consistent with corporate direction and directs resources ($) to where they provide the maximum business value within the financial guidance provided.

Role of Calibration Session

- **If risk assessments are not properly calibrated** across business units, the optimized **investment portfolio may not** adequately **reflect the Company's priorities**
- The calibration sessions will focus on two dimensions:
  - Investment Flexibility
  - Risk Assessment Validation



Optimized Investment Plan

Why calibrate risk across LOBs?

Everyone **competes for funding** – if there is **too much "mandatory"**, **other work is reduced/deferred**

Observation:

- An increasing portion of the enterprise portfolio is being deemed "mandatory"

Workshop Purpose:

- To understand the level and composition of "mandatory" investments
- **Distinguish between investments that are beyond the control of the Company** *("mandatory")* **and those that are at the discretion of the Company** *("flexible").*

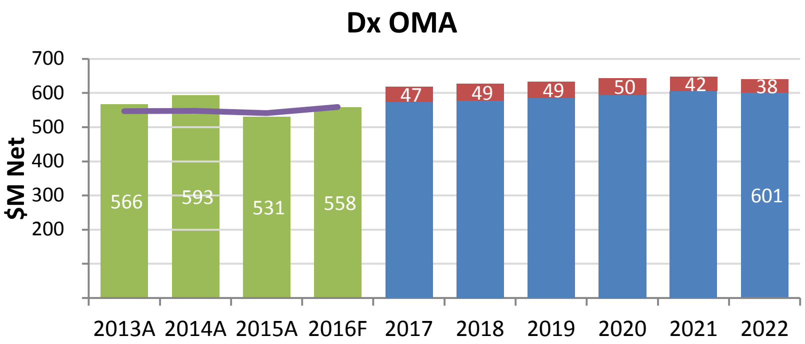
Implication:

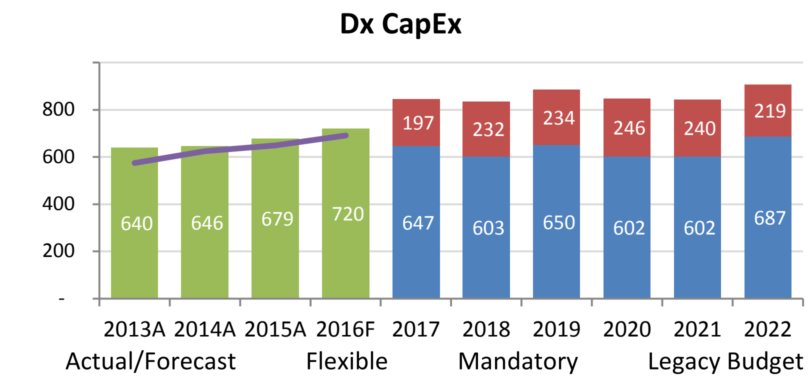
- You are all competing for limited resources
- **If too much** of the investment portfolio is deemed to be **"mandatory" there is limited ability to accommodate more discretionary work** *(i.e. select projects/incremental volumes get "squeezed out").*

Potential Outcomes:

- **Acceptance** of "mandatory" investments **or reclassification** of "mandatory" investments
- Separation of investment elements into base (mandatory) and enhancement (flexible)

Why discuss investment flexibility?





Mandatory investments include:

- Executing Projects
- Demand/Contract based programs
- Vulnerable(minimum) level of programs
- Single alternative programs
- Non-shift-able, unreleased projects

Data as of March 14th, 2016

Flexible investments include:

- Incremental Project/Program levels
- Shift-able, unreleased projects (shift-able by 1 year or more)

Everyone competes for funding – if risk assessments are not aligned, the investment plan may not reflect the Company's priorities

Observation:

- Risk assessments across LOBs may not be consistent

Workshop Purpose:

- To understand each LOB's approach to risk assessments
- **To normalize risk assessment outliers and improve consistency**

Implication:

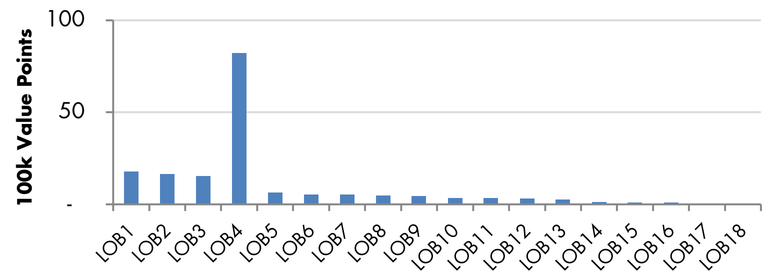
- You are all competing for limited resources
- The optimization process seeks to maximize value within the financial guidance identified
- **If an investment's risk mitigation** or productivity enhancement is **"overstated",** that investment may be selected in the optimization process, while **other worthwhile, higher operational risk investments** may be deferred *(assuming the mandatory level of investment does not exceed the financial guidance)*

Potential Outcomes:

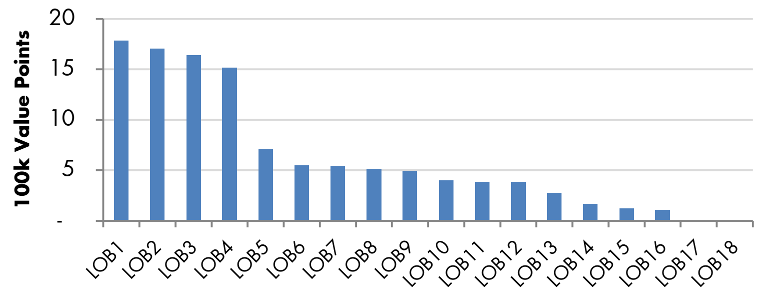
- **Acceptance or revisions** to risk assessment

Why validate investment risk assessments?

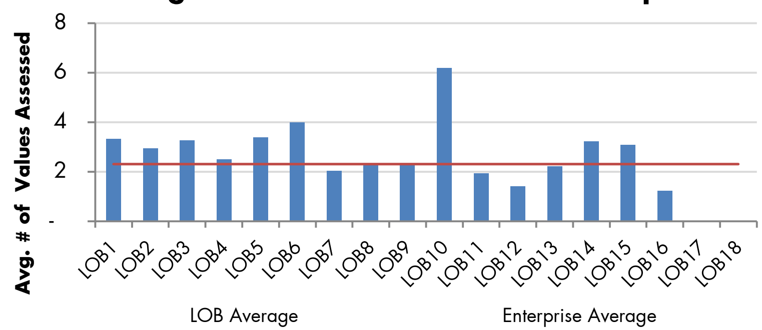
Average Value per Investment (All Business



Average Baseline Risk per Investment (All



Average # of Business Values Assessed per



Data as of March 14th, 2016

The Risk Calibration session will cover Investment Flexibility and Risk Analysis

Session	Key Questions to Consider/Address
Investment Flexibility	**Portfolio Questions:** • Is there variability in your investments? • How did you arrive at your mandatory/vulnerable/minimum funding level request? • What type of work is included in your mandatory bucket? • If the investment is mandatory, why now or at the time proposed? • Did you contemplate +/- 10% adjustments to your portfolio? • Did you consider a 1 or 2 year deferral? • Is the entire investment mandatory, or are there flexible/discretionary elements? • Is your mandatory level aligned with historic budgets or historic expenditures? **Select Investments:** • How did you determine your minimum funding level?
Risk Analysis	**Portfolio Questions:** • What are the largest risks facing your portfolio? • What would the impact of a +/-10% change to your investment portfolio be? • How did you determine the business values applicable to your portfolio and the level of risk mitigated? • Are you relatively aligned with other planning groups? **Select Investments:** • How did you assess the baseline and residual risk?

What will be covered?

6 week outlook includes investment development, customer consultations, risk calibration and management review

- **Risk calibration session is scheduled for July 12**
- A **standard template** will be developed and communicated to all participants; the expectation is that all materials will have a similar look/feel
- **Data will be pulled approximately 15 days before the calibration session** and sent to participants *(week of June 27)*:
  - Historic/forecast expenditures vs. current minimum/flexible investment outlook
  - Average risk/value assessment relative to other LOBs
  - Listing of significant investments to be covered as part of the workshop; significant investments may be identified based on:
    - » Risk/value score;
    - » Planned expenditures;
    - » Baseline risk assessment;
    - » Value per $; or
    - » Other considerations

What's next?

Investment Plan will be formed by multiple inputs and result in changes throughout the planning process

Requirements	
Pricing	Agreement on costing between Planning & Operations; *Unit Prices will need to be updated with any G2G productivity savings.*
Investment Categorization	Identification of investments as Foundational vs Enhancement work; Reporting Framework for Rate Filing
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Multi-Stage Review	**Investments to undergo detailed review pre-optimization to eliminate tedious post-optimization changes; Post-optimization portfolio review to ensure cross-functional alignment**

Multi-stage review to minimize pre-optimization changes and ensure cross-functional alignment

	Investment Health Report	Manager's Checklist	AIP Workflow	Enterprise Engagement	Executive Review
	Manager/Director			Director	CEO/CFO
Objective	Report data quality issues Completion/ Approval targets to manage workload	Verification of key investment details	Official record of investment approval	Assess resource requirements to ensure work program, including planning timelines are achievable	Verify Investment Plan Alignment to Corporate Objectives
Reporting	Email Communication Based on Driver Owner	Manager via SharePoint Investment Planning Process Metrics	Manager/ Director in AIP Investment Planning Process Metrics	Meeting Minutes	Meeting Minutes
Outcome	Adherence to deadlines, improved data quality	Improved data quality	Record of Approval	Cross-functional alignment for an achievable plan	Internally approved plan

Dx Investment Plan Schedule

June 2	• Director Kickoff
June 6 - 30	• Planner Input
July 4 - 29	• Manager/Director Review • Risk Calibration Session – July 12
Aug 1 – 12	• QA & Optimization • **First Draft of Accomplishment File**
Aug 15 – Sept 16	• 3rd Party Review • Enterprise Engagement • iPAD Development
Sept 19 – 30	• Investment Plan Finalization • CEO/CFO Plan Review – Sept 26 • **Final Draft of Accomplishment File**

Customer Consultations

Productivity Studies

Prioritized IPP Pain Points to be Addressed this cycle:

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Pain points prioritized by criticality and ease of addressing

#	Pain point		Resolution
1	Lack of clarity of financial boundary conditions	✓	Multi business unit review
2	Spend categories not linked to outcome-driven objectives	✓	Investment Categorization
3	Business values/weights do not reflect current corp. strategy	✓	Maintain status quo
4	Planners/managers do not understand optimization process	✓	Management Training
5	Lack of feedback received on input to IPP process		TBD – Prior to Next Cycle
6	Planner inputs are of inconsistent quality	✓	Manager's Checklist
7	Insufficient time for investment definitions + quality check	✓	Manager's Checklist
8	Inaccuracy / lack of cost-estimates for potent. investments		TBD
9	Risk evaluation process is not consistently applied	✓	Risk Calibration Session
10	Invest. not tracked against expected perform. outcomes		TBD

"Quick wins" (1–4) Intermediate targets (5–7) Long-term efforts (8–10)

Regulatory Expectations

Karen Taylor

APPENDIX

Dx Investment Plan Schedule

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Date	Segment	Key Stakeholder(s)	Description
May 25 - 31	Director/Management Training	Investment Management, Planning	AIP Team to provide insight into AIP's optimization process and review requirements for the new Manager's Checklist
June 2	Investment Planning Kickoff	Planning, Operations, Finance, Regulatory & Investment Management	AIP Team to review schedule, requirements etc of the Dx Investment Planning Process with key stakeholders at Director/Management Level
June 6 – July 1	Planner Input	Planning (Operations)	AIP Tool Open to Planners with investments under Dx CapEx & Dx OMA only
July 4 – July 29	Management Review & Approval	Planning (Operations)	Management Review including Manager's Checklist with Final Investment Approval through AIP Workflow
July 12	Risk Calibration	Planning	AIP Team to facilitate Risk Calibration Session(s) to determine consistent risk approach across the all Planning organizations
Aug 1 –12	QA Optimization	Investment Management	AIP Team to run QA & optimization on Dx CapEx & Dx OMA only
August 12	**Hand-off for 3rd Party Review**	**Investment Management**	**Updated Accomplishment File due for 3rd Party Review**
Aug 15 – 26	3rd Party Review	Regulatory	Optimized Dx Work Program to undergo 3rd Party Review
Aug 15 - Sept 16	Enterprise Engagement	Planning, Operations, Finance, Regulatory & Investment Management	Planning and Operations to review Accomplishment File as a result of all changes identified, provide feedback with any remaining adjustments required, final Director Approval
Aug 15 – Sept 16	iPad Development	Planning	Planning to document investment strategy and outcome as a result of the Planning Process in their respective iPADs
Sept 19 - 30	Accomplishment File #3 Finalization	Planning & Investment Management	AIP Team to finalize updates prior to Business Planning Hand-off
Sept 26	CEO/CFO Investment Plan Review	Planning, Operations, Finance, Regulatory & Investment Management	Investment Plan Review Session for CEO/CFO Approval (previously IRRC)
Sept 30	**Business Planning Hand-off**	**Investment Management**	**Updated Accomplishment File due for Business Planning Board Prep**

Foundational Investment Categorization

Category	Description
Asset renewal / maintenance	Investments focused on minimizing life-cycle asset costs while maintaining an acceptable risk and continuously delivering reliable service
Customer connections (new customers)	Investments related to providing service to new customers, including construction, meter installations, and other required investments to address load growth
Safety, security and enviro (compliance)	Investments to ensure transmission and distribution facilities and operations are in compliance with environmental, safety, and other regulations
Customer projects (existing customers)	Investments related to customer-requested work from existing customers, including design and relocation of services
Outage response	Investments (primarily O&M) focused on responding to outages and restoring service
Facilities	Routine investments for building required facilities for customer and workforce needs
Enterprise IT	IT capital programs related to hardware replacement, secure access to information and technology and investments related to Hydro One's Enterprise Information Systems

Enhancement Investment Categorization

Category	Description
Reliability enhancement	Investments focused on providing improved reliability (e.g., reducing SAIFI / CAIDI) through addressing root causes of reliability issues or mitigating reliability impact from routine events
Grid modernization (comms / automation)	Investments to modernize the electrical grid to provide real-time visibility and control capabilities . May include smart meters, remote controllable devices. or enhanced communication capabilities.
Advanced analytics	Investments focused on databases, software, and analytics applications to collect and utilize operational data (e.g. meters, assets, customers)
DER enablement	Investments focused on enabling the integration of significant amounts of new distributed resources, such as rooftop PV
Additional capacity / reserves	Investments which improve system resiliency through increased circuit redundancy, additional load capacity, and storage capabilities
Grid hardening	Investments which increase the grid's ability to reliably operate during major events related to weather or other adverse conditions

Investment Planning Training 2017-2022

Winter 2016

Introduction

- Who's Who?
- Safety Moment
- Guest Address

Agenda

Course	Duration
Investment Planning Process	1 hour
Risk Assessment Methodology - Featuring Net Income & Revenue Requirement	1.5 Hours
AIP Tool Training	3 hours

Introduction to Hydro One's Investment Planning Process

Winter 2016

Agenda

- Overview
- Module 1: Business Planning vs Investment Planning
- Module 2: The World Affecting your Investment
- Module 3: Your Responsibility as an Investment Owner
- Module 4: How Investments are Selected
- Module 5: Investment Planning Approvals
- Module 6: Related Processes

Objectives

- Learn about the Investment Planning Process (IPP) and its interdependencies to the corporate Business Planning Process
- Understand the context within which the Investment Plan is being developed and the process goals/metrics
- Recognize the steps in the high-level IPP
- Be able to identify focus areas and expectations of the IPP, including productivity and related metrics
- Understand the relationship between investment planning and parallel processes such as work release, budgeting, resource planning, etc.
- Understand the basics of the optimization process

Module 1

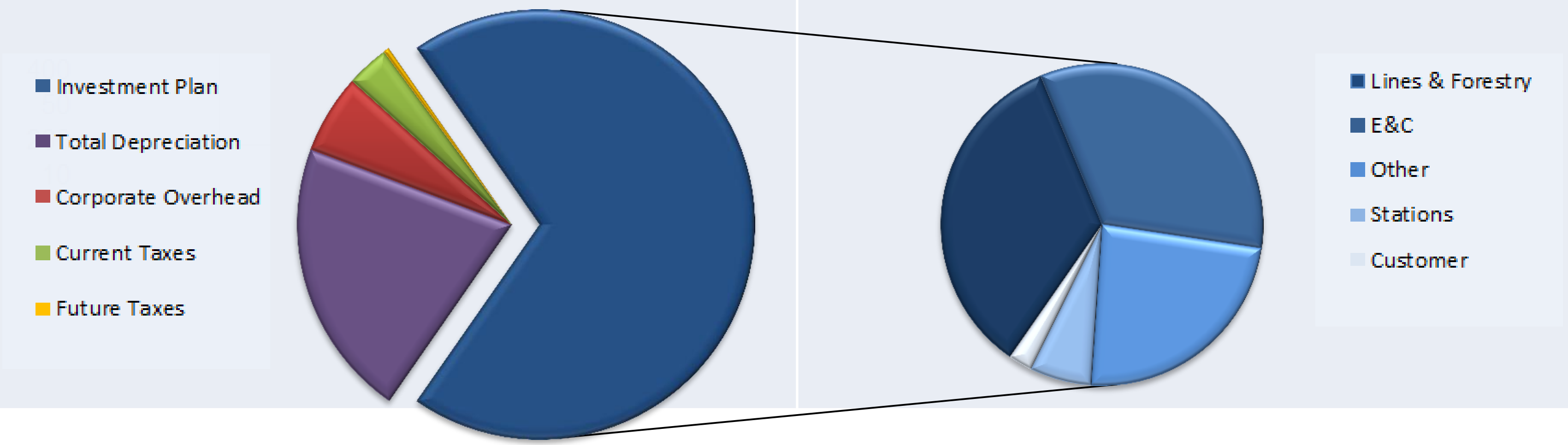
BUSINESS PLAN VS. INVESTMENT PLAN

Business Plan vs Investment Plan

Corporate Business Plan	Investment Plan
Overall 5 year Financial Outlook for *Hydro One Limited.* that spans: • Subsidiaries (Networks, Remotes, Telecom, Acquisitions) • Investments • Staffing & Overheads • Revenue Forecasts • Other (Tax, Depreciation, Working Capital, etc.)	**The *Hydro One Networks* investments planned for the selected time period (all the work that we do):** • Sustainment • Development • Operations • Customer • Other **The Plan Considers:** • Asset Needs (Short-term and Long-Term Risks) • Corporate Objectives • Financial, Regulatory, and Resource Constraints

$3.6B CapEx and OM&A

$2.5B CapEx and OM&A



Your Role in the Investment Planning Process

Module 2

THE WORLD AFFECTING YOUR INVESTMENT

2016-2020 Investment Plan Update

- 2016 was approved by the Board for budgetary purposes on January 14th
- 2016-2018 to be submitted to the Board in early May for approval prior to Tx Rate Filing at the end of the month

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Lessons Learned

- Dedicated Quality Assurance period to resolve issues/discrepancies
- Enhance Coordination/Collaboration between planning groups
- Remodel Training Material and Tool Packages
- Consistent Risk Approach
- Direction regarding concept and effects of Investment Shifting and Alternative Levels
- Lessons Learned Report

Corporate Strategy: Becoming Canada's Leading Utility

	Uniting Behind the Goal 2014	Enabling our People 2015-16	Unlocking Performance 2017-18
Safety	Creating an injury free workplace and maintaining public safety		World Class safety performance
Customer	Satisfying our customers		Satisfying experience & trusted partner
People	Championing people and culture		High performance culture
Business Excellence	Reliable, affordable Tx & Dx systems Improve productivity and cost effectiveness Increasing value for our shareholder		Reliable Power Cost Effective Pride in Shareholder Value Creation

Strategic Plan 2014-2019

Corporate Scorecard 2014-2019

Canada's Leading Utility

Our Employees, Customers, and the people of Ontario

BELIEVE

We are a company of great people providing

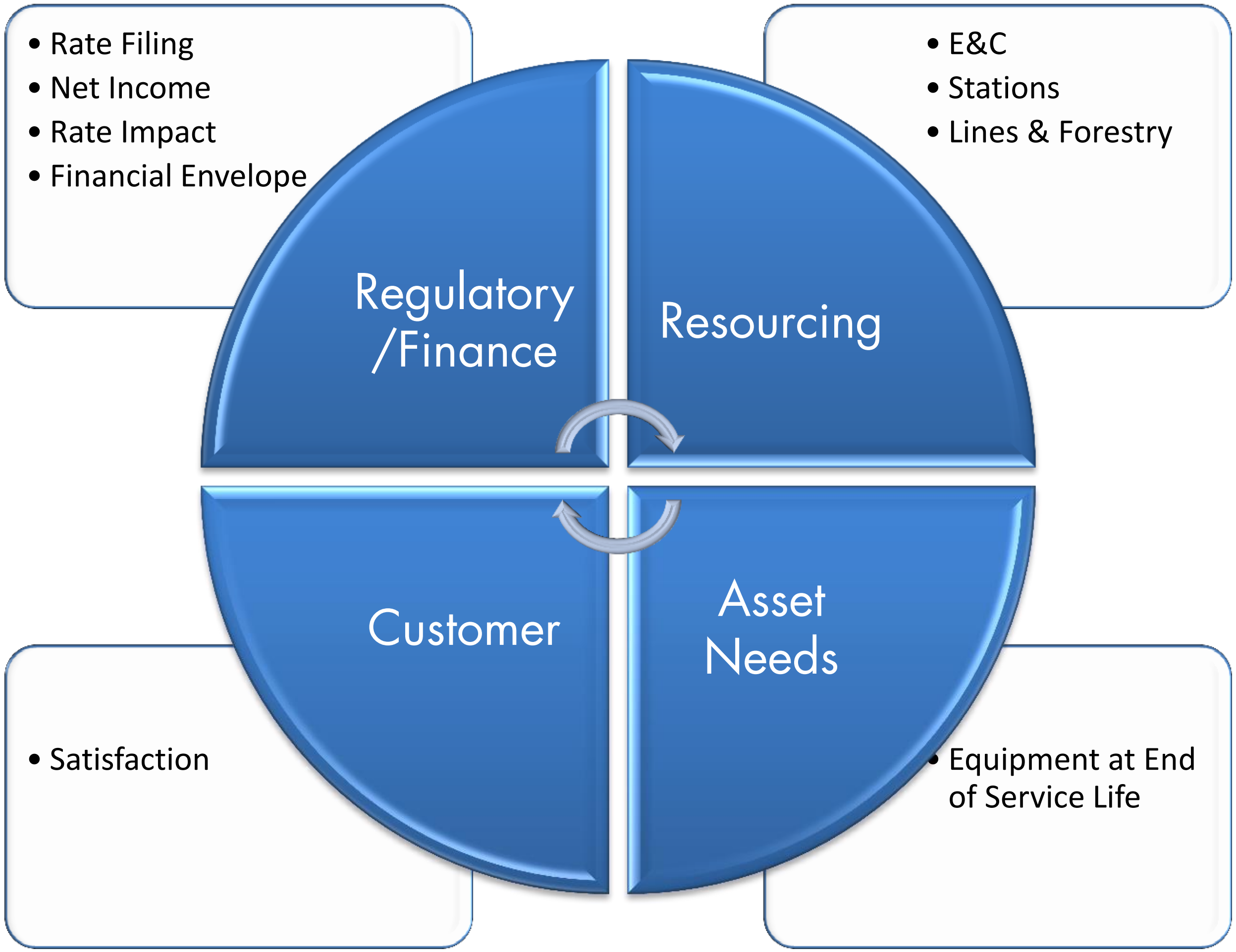
safe, reliable, excellent and affordable service

Parameters → Investment Input → Investment Review → Optimization → Enterprise Engagement → Approval

Hydro One's Business Values

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Constraints



Financial Framework

Financial Envelope

Asset Need	Inflation	Productivity	Rate Base Growth 4.2%

Investment Plan Guided by Financial Envelope of Previous Plan

Regulatory Framework

- Plans should be consistent with approved rate decisions/applications in-flight
- Transmission
  - Consistent with 2016-2020 Plan and align to rate filing for years 2017-2018
- Distribution
  - To follow OEB Decision for 2017 and assume IRM rate regime (inflation less productivity) for 2018-2022

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Benchmarking

- OEB has mandated productivity studies for both Transmission and Distribution
- Outcome from results of the Studies to be expected in the summer
  - May cause potential changes to the plan between internal approval and Board Approval submission

Touch point

- Name 3 Key Business Values for Hydro One

- What expected decisions may result in a change to the Investment Plan?

Module 3

YOUR RESPONSIBILITY AS INVESTMENT OWNER

Role of Investment Owner

Determine Investment Need

Evaluation and Quantification of Options

Risk Analysis

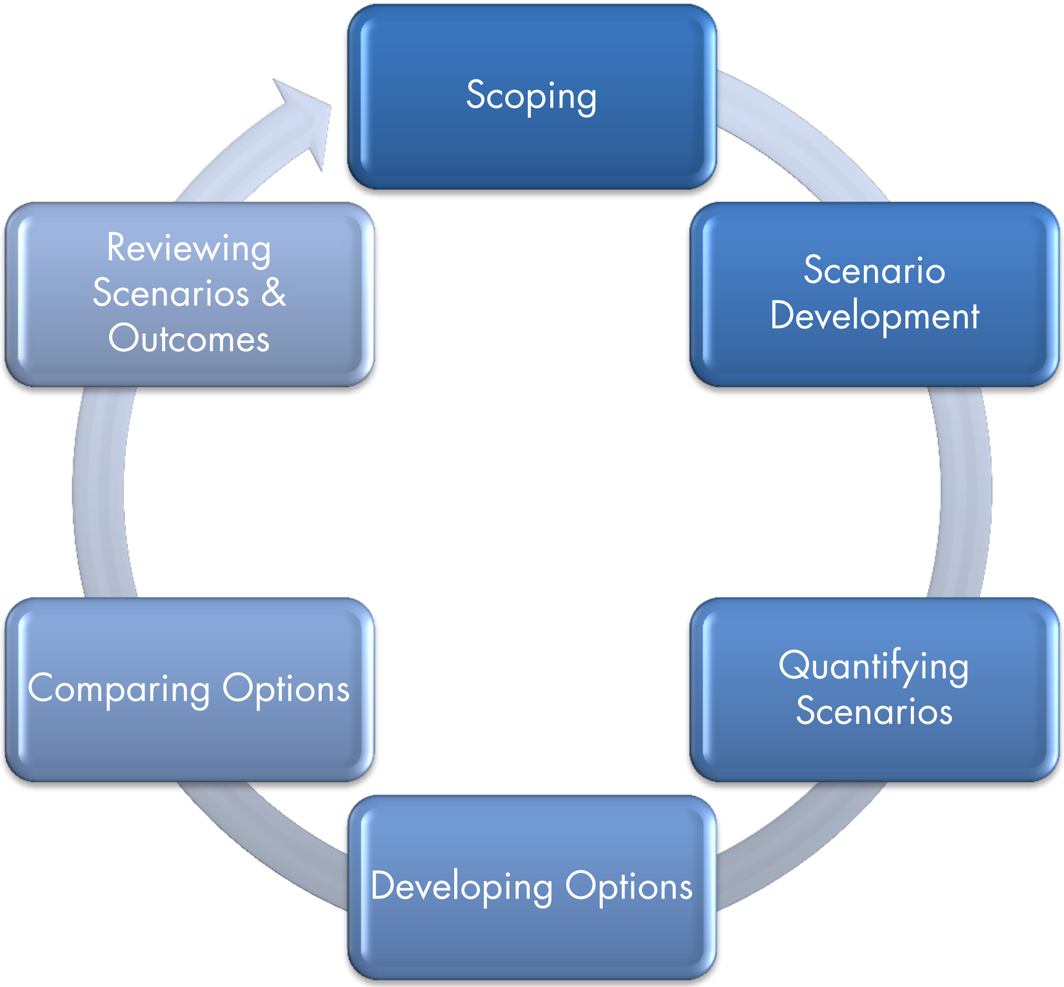
Alignment to Investment Expectations

Workflow Submission

Investment Strategy

- Audit Approach to Investment Planning
- All investments must be justified through data analysis with supporting documentation
- Focus on Productivity with emphasis on unit accomplishments

Investment Assessment Process



Program

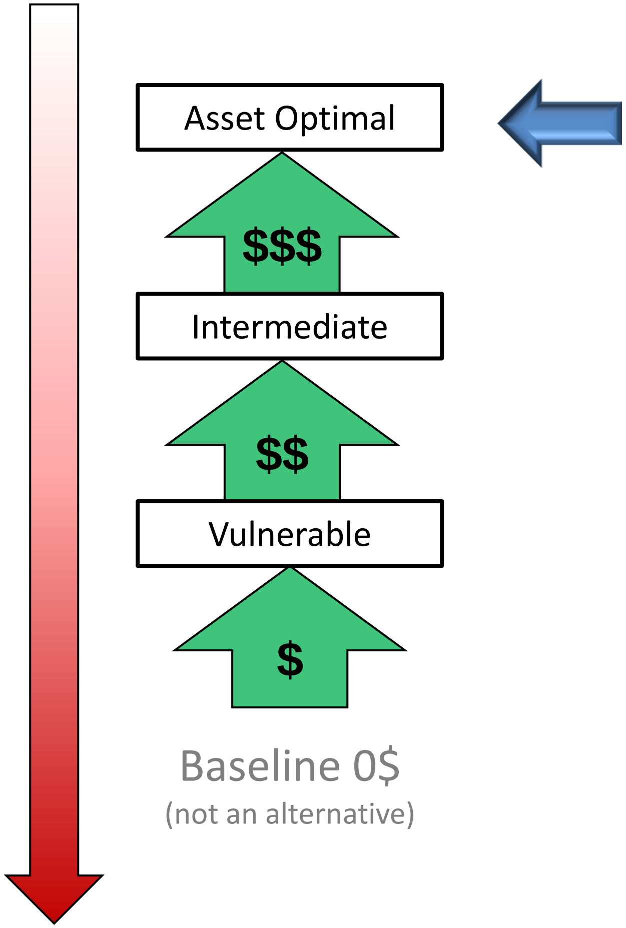
Definition **(as per SP1078)**

The total of all transactions relating to a specific body of work where the type of work **recurs year over year**. The extent of the work executed in any particular year, may change from year to year depending on its ranking in the prioritized programs and the overall availability of funds. Alternative approaches do not exist to achieve the objective.

NOTE:

In-Service Additions calculated on a ***ratio*** basis

Program Alternatives



Recommended or Proposed Alternative should align to your Investment Strategy based on your analysis and in turn align with the Corporate Strategy

Every Alternative is a valid option for consideration

Note: Demand Programs will only have one alternative

Project

Definition (as per SP1078)

The total of all transactions relating to a specific body of work that is a **one-time event** that occurs during a specific time period. This period may cover more than one fiscal year. **Alternative** approaches can be taken to achieve the objective and there is a greater level of risk.

NOTE:

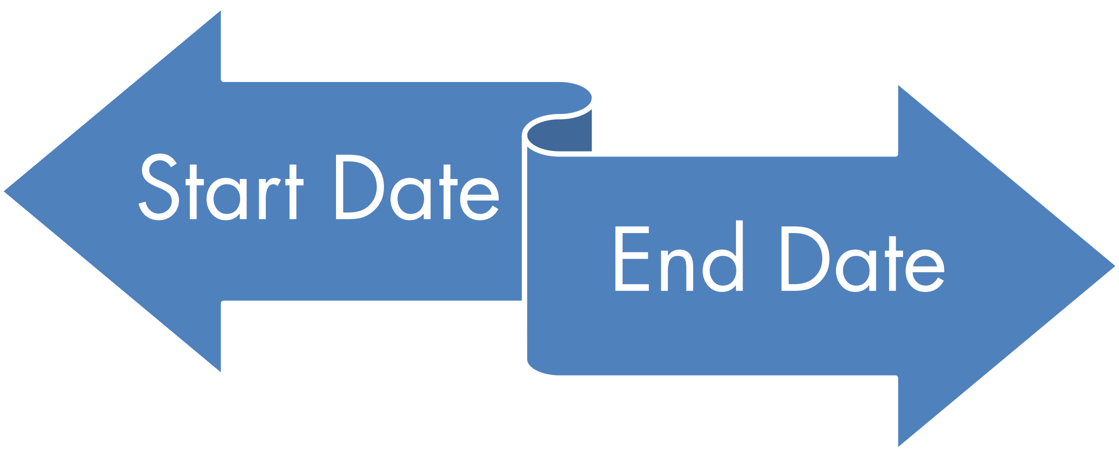
In-Service Additions determined by ***In-Service Date of total Net Costs***

All Integrated Investments are now **PROJECTS**

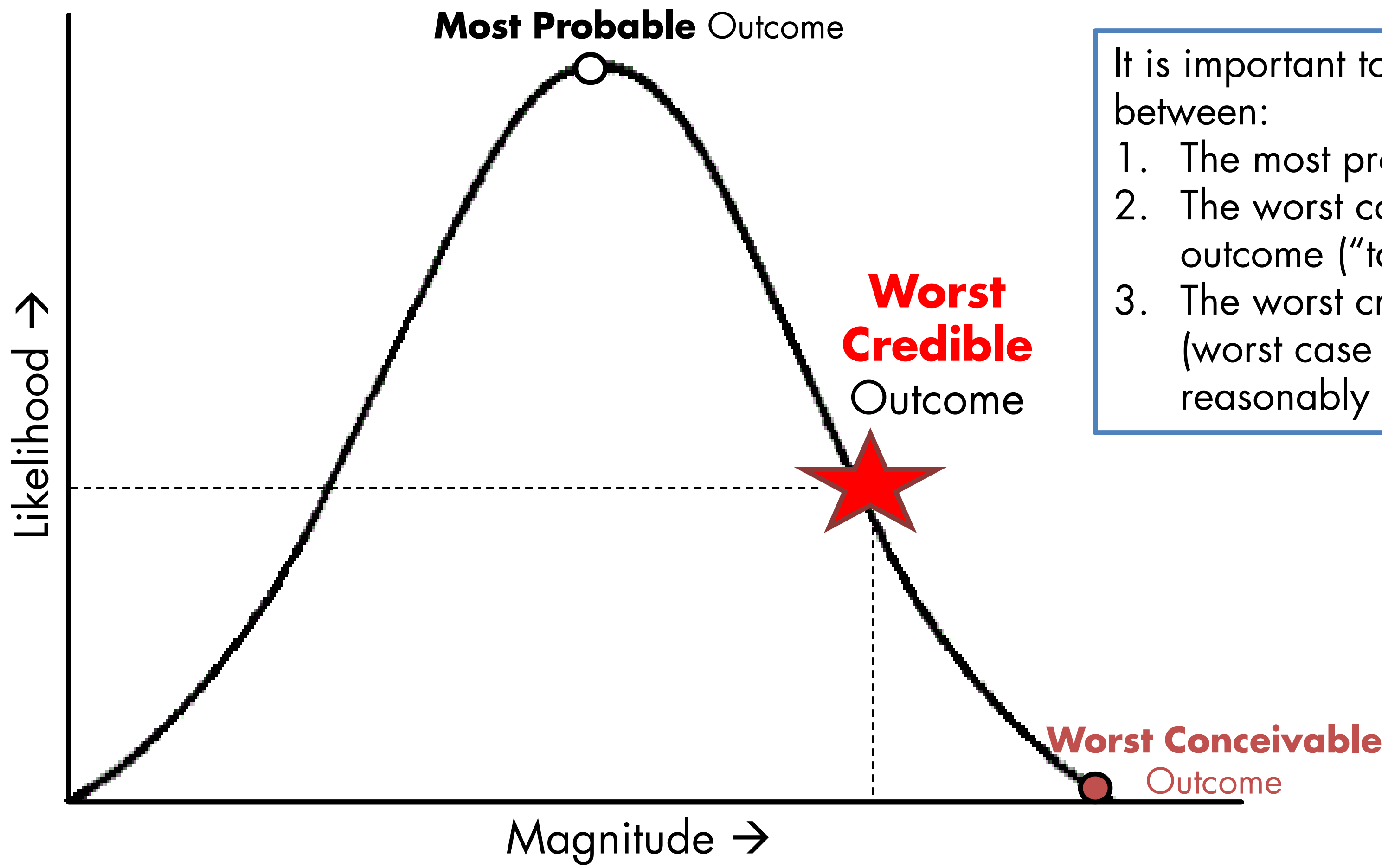
Updates to **Released Projects** are based on Multi-year Forecast from Service Provider and therefore are not the responsibility of the Investment Planner

Project Alternatives

- Project Alternatives are determined by the ability to **Shift** an investment
- Criteria based on the Earliest Start Date and the Latest Start Date
- Multiple Alternatives may be provided where appropriate
- Allows a level of confidence for those investments containing:
  - Signed Customer Agreement
  - Currently in the estimating process
  - Long-lead material



Hypothetical Risk Distribution Curve



It is important to differentiate between:

1. The most probable outcome
2. The worst conceivable outcome ("tail risk")
3. The worst credible case (worst case that may reasonably occur)

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

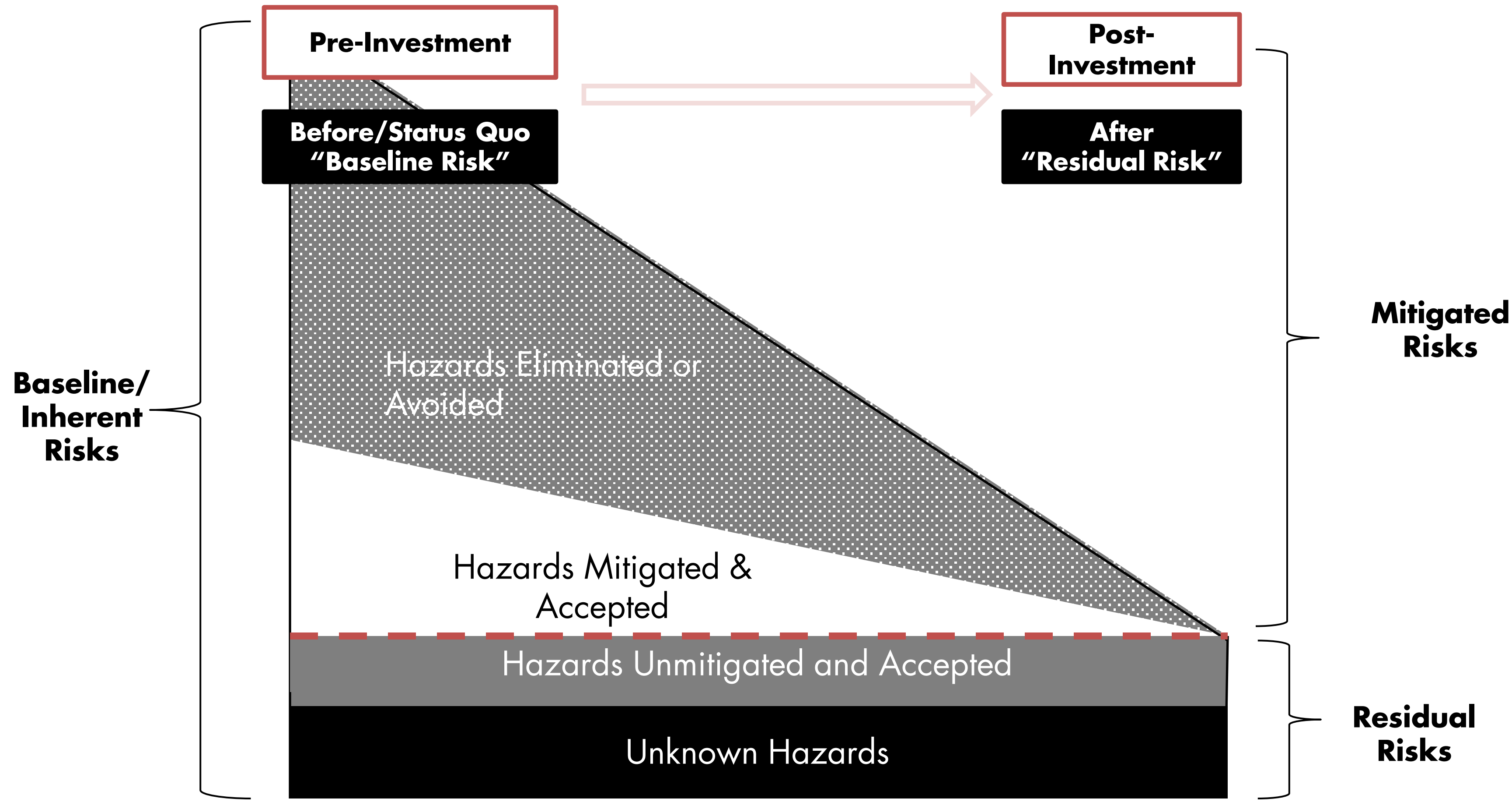
Investment Planning Risks Assessments

Hazards/Threats
- Fire
- Explosion
- Severe Weather
- Hazardous materials spill or release
- Mechanical breakdown
- Equipment condition
- Cyber Attack
- Physical Attack
- Theft and vandalism
- Obsolescence
- Inefficient processes
- Non Compliance

Assets at Risk
- People
- Power system facilities
- Customer Relationship
- Systems/Equipment
- Information Technology
- Operational performance
- Business Operations
- Financial profile
- Regulatory and legal obligations
- Environment
- Company Reputation

Consequences
- Workforce/Public Injuries
- Performance and reliability
- Erosion of customer goodwill
- Environmental release/contamination
- Financial loss
- Loss of Shareholder confidence
- Regulatory credibility
- Regulatory compliance
- Fines, penalties and sanctions

Risk Informed Investment Decisions



Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Expectations & Metrics

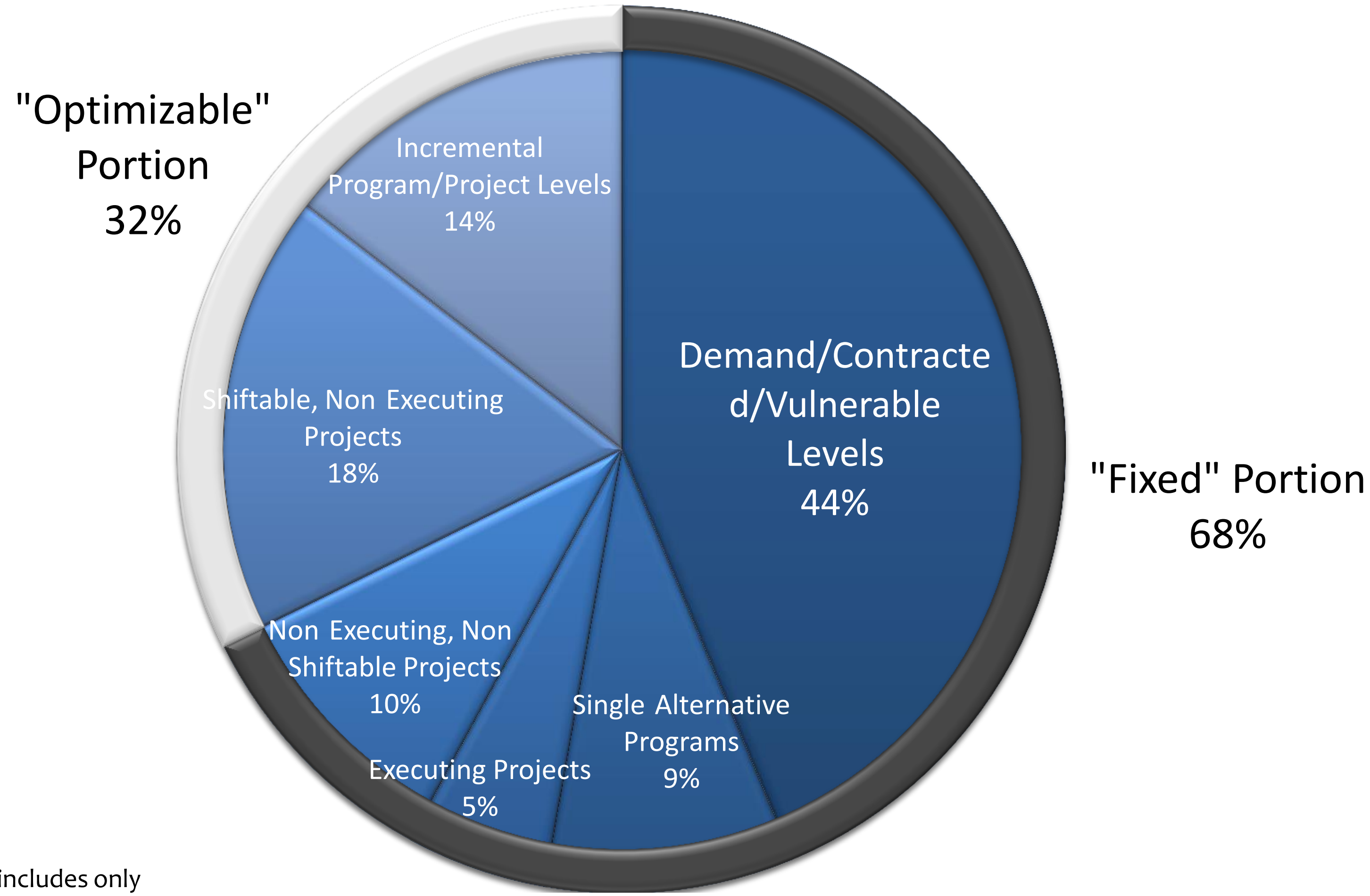
- Key Performance Indicators (KPIs) will be implemented to measure the end-to-end Investment Planning Process

- Including overall metrics such as:
  - Plan contributes to acceptable rate increase
  - Balanced plan developed & aligned to corporate guidance
  - Increase the "optimizable" portion in the plan

Note: ⍓ indicates metric

Investment Plan Optimization

5-Year Net Total (2016-2020)



As of May 14, 2015; includes only selectable alternatives

Investment Input Expectations

Category	Components	Metric
Supporting Documentation	Asset Analytics	⍓
	Investment Development & Justification	⍓
	Scope	⍓
	Financial & Asset evaluations	⍓
	Risk/Value Assessment	⍓
	Potential Need Notifications	⍓
Ability to Optimize	Shifting of Non-Executing Projects	⍓
	Viable Alternatives for Non-Demand/Non-Contract Programs	⍓
	No Near-Term Placeholders	⍓
Planning Timelines	Logical and aligned to Estimating guidelines	⍓
	No Year End In-Service Dates (ISD)	
Enterprise Engagement	Discussion of Key Investment Details such as:	
	• All cost assumptions are to be agreed by Work Program Management	⍓
	• UPC	⍓
	• Sourcing Model	
	• Planning Timelines	

Tx Investments with Dx Contributions

- Both ARs to have same Service Provider

- Funding Party (Dx) has a Gross Plan equal to the receiving party's (Tx) Capital Contribution from Dx
  - Note: Tx may have capital contributions in addition to Dx

- The timing of the matching Dx Gross $ and Tx Cap Contribution must be equal on an annual basis and offset one another

Investment Input Quality & Analysis

- IM Team to complete Pre & Post Investment Submission Review with feedback provided on data quality and completeness
- Reviewer Feedback will be provided to the investment owner via a meaningful Manager Check-list
  - Checklist will serve as a basis for many KPIs
- Essential for Investment Quality, as minimal changes will be allowed post-optimization

Metric

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Investment Approval Workflow

Investment Owner (IO)		e.g. Don Mastrangelo
Interim Reviewer #1	Optional	Ken McNeil
Driver Owner (Manager/ Director)	Mandatory	Bruno Jesus
Interim Reviewer #2	>$15M/10M Optional	
Portfolio Owner (Director)	>$15M/10M Mandatory	CK Ng

- All Investments must be approved through Workflow and status will be tracked and reported

Metric

Investment Approval Submission

- Investment Planning Approval Documents (iPADs) are to be submitted post Workflow Approval for each Driver
- Asset Portfolio Documents (APDs) are to be submitted for asset types where appropriate
- Developed by the Director and based on investment owners proposed scenario for investments contained in associated Driver
- Used during IRRC Planning Review to provide insight into Strategies and Risk associated with Investments within the Plan

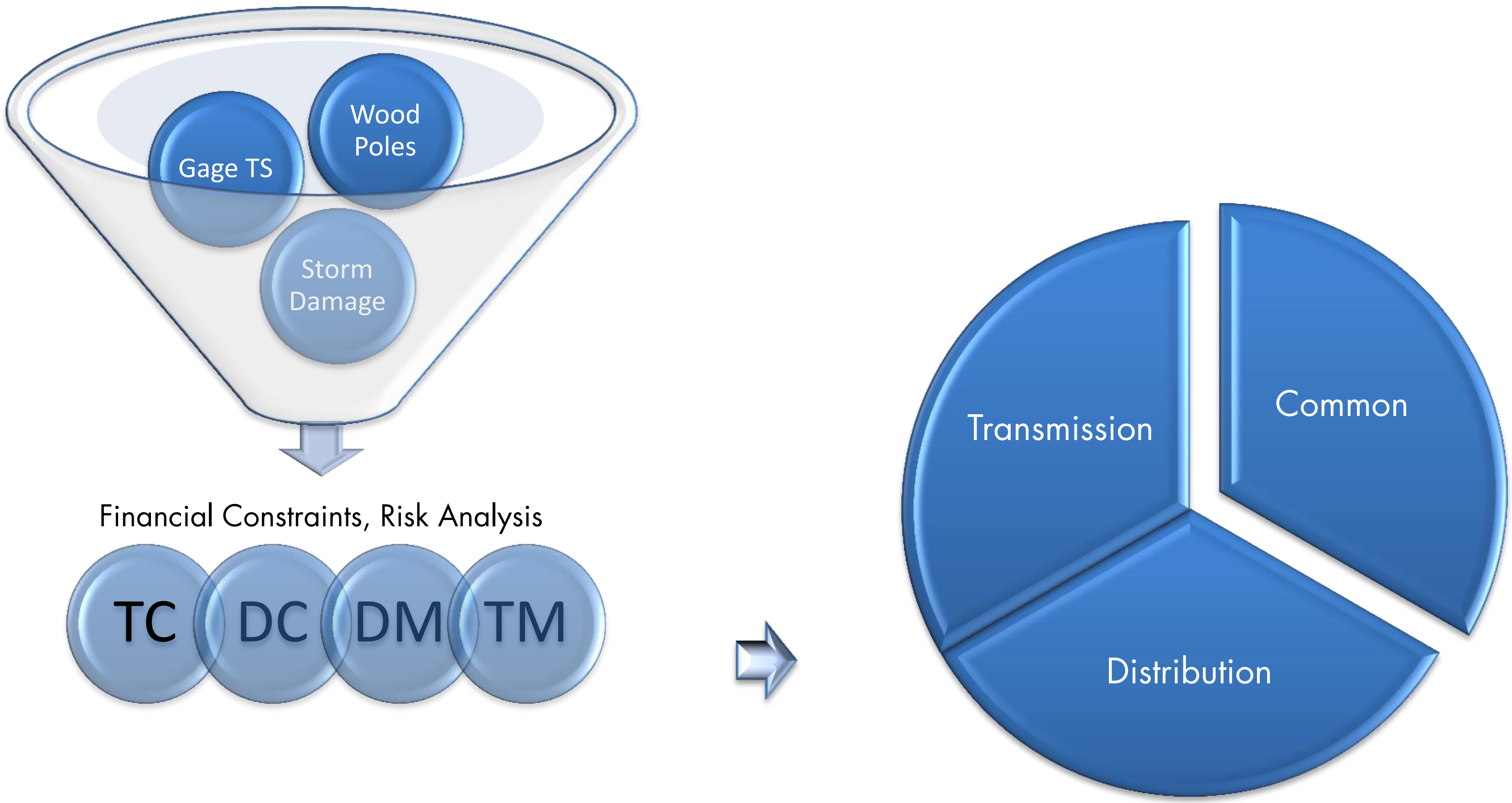
Touch Point

- What are the key responsibilities of an Investment Owner?
- Name three expectations for an investment that will be tracked as a metric

Module 4

HOW INVESTMENTS ARE SELECTED

Optimization



Best Selection and timing of investments

Optimization Analysis

- Various scenarios are run by the IM Team to understand the data and achieve an optimal plan

- Risk Calibration sessions will be completed pre-optimization

Enterprise Engagement

Enterprise Engagement Expectations

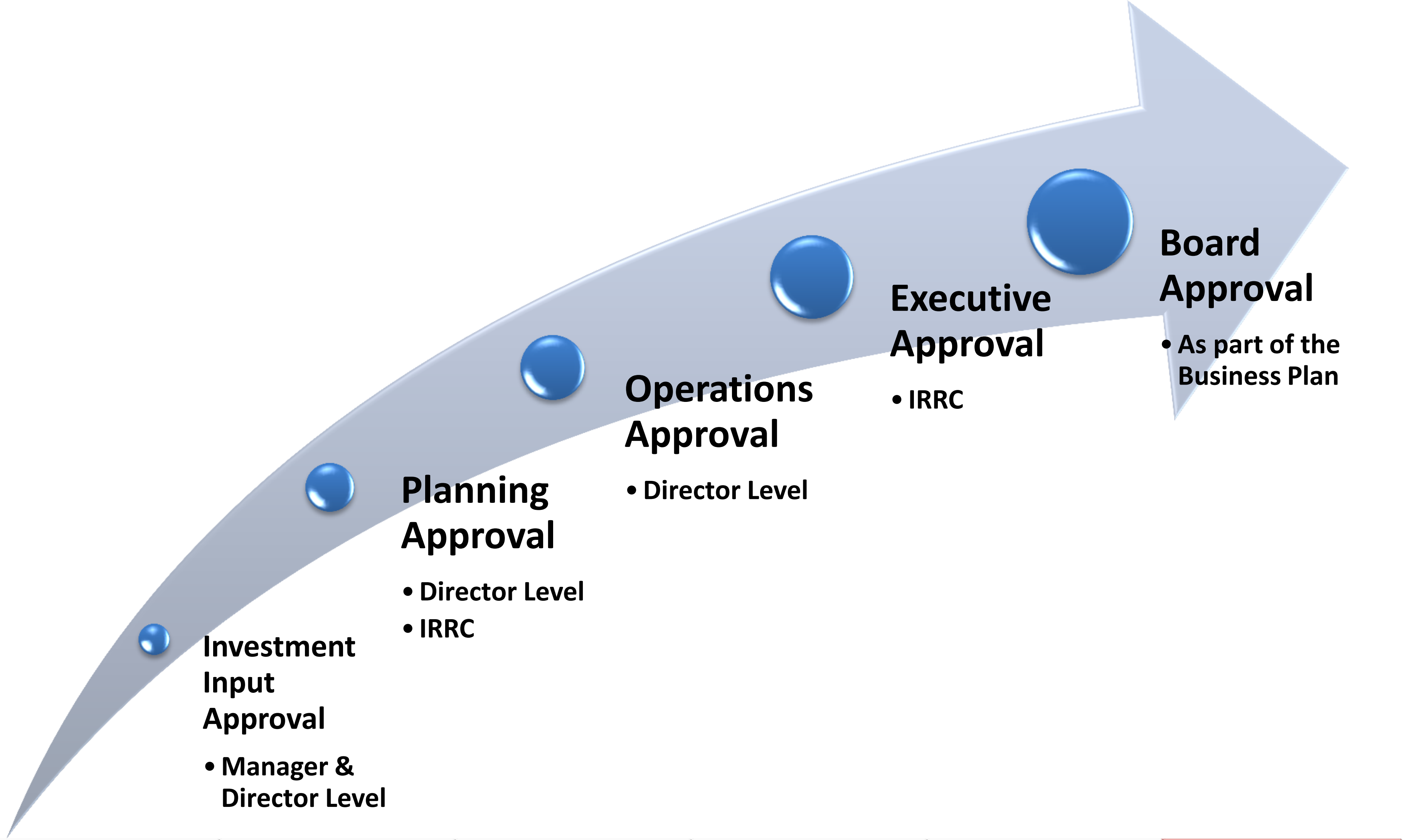
Expectation	Metric
Unit Prices from Operations are available to Planners and have been agreed to by both parties	☒
Operations (thru Finance) will provide a multi-year forecast of released projects Monthly	
Collaborative Effort between Planning and Operations for Funding Redirection	
Collaborative process to ensure investments have accurate costs and realistic timelines considering resource constraints	
All LOBs will participate in the finalization of the Investment Plan	☒

☒ Metric

Module 5

INVESTMENT PLANNING APPROVALS

Investment Plan Approval Stages



Parameters > Investment Input > Investment Review > Optimization > Enterprise Engagement > Approval

Module 6

RELATED PROCESSES

Related Processes

- ACER/Work Release
- Budgeting
- Resource Planning
  - Estimating
  - Stations including CMS
  - Construction Services
  - Lines & Forestry
- Outage Planning

Schedule

Date	Segment	Duration
Training		
Jan 11 - Feb 10	Planner & Manager Training	4 weeks
Input		
Jan 30	Operations provides Unit Price Catalogue; Planning accepts Unit Price Catalogue	1 day
Feb 1 - Mar 28	Planner Input	8 weeks
Feb 24	Investment Planning Drop-in Session	½Day
Mar 9 - 16	QA Review	1 week
Mar 22	Investment Planning Drop-in Session	½Day
Mar 28 – May 4	Manager/Director Review of Input	4 weeks
Apr 27 – May 3	Investment/Risk Calibration	1 weeks
Optimization and Review		
May 5 – May 18	QA and Optimization	2 weeks
May 19 – 25	Director Review of Optimization Results	1 week
May 26 – June 1	Executive Review	1 week
Enterprise Engagement		
June 2 – 20	Executing LOB Review (Lines, Forestry, Stations, E&C)	3 weeks
Investment Plan Approval		
June 30	IRRC IPP Review and Approval	1 day
June 30	Investment Plan Proposal Complete	

Investment Planning Team

[redacted]

- Training Site
- AIP Tool
- Draft Accomplishment File
- AR Docs
- Risk Consequence Table
- Project Hub – Gantt Chart Directory

Questions??

School Energy Coalition Interrogatory # 2

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

Interrogatory:

Please provide a copy of Hydro One's 2015-2017 corporate scorecards.

Response:

Please see attached team scorecards for the period 2015-2016. For the 2017 scorecard, please see Attachment 4 to Exhibit C1, Tab 2, Schedule 1.

APPENDIX

HYDRO ONE INC.

Recommended 2015/2019 Corporate Scorecard[1,2,3]

Strategic Objective	Performance Measure	2014 Target	2014 Actual	Targets 2015	Targets 2019
Injury Free Workplace	Total Recordable Rate (OHSA Recordable) # Recordable per 200,000 hours worked	1.9	1.8	1.7	0.9
Satisfying our Customers	**Customer Satisfaction – Transmission[4] (% satisfied)**	**n/a**	**76**	**78**	**90**
	Customer Satisfaction – Distribution[4] (% satisfied)	**n/a**	**84**	**86**	**90**
	Connection of New Services (% completed in ≤ 5 days)	90	97	95	95
	Billing Success (NEW) (%)	**n/a**	**97**	**99**	**n/a**
	First Call Resolution (NEW) (%)	**n/a**	**81**	**83**	**87**
Continuous Improvement & Cost Effectiveness in the Building and Maintaining of Reliable Distribution and Transmission Systems	Transmission Unit Costs (OM&A/Gross Fixed Assets)[5] %	2.9	2.7	2.8	2.5
	Distribution Unit Costs (OM&A/Gross Fixed Assets)[5] %	5.7	6.1	5.4	4.7
	Duration (SAIDI) – Transmission (minutes per delivery point)	8.9	11.8	10.0	8.8
	Duration (SAIDI) – Distribution (hours per customer)	6.7	7.4	7.1	6.9
Maintaining a Commercial Culture that Increases Shareholder Value	Net Income After Tax ($M)[5]	668	747	750	941
	In-Service Capital – Transmission (% of Plan)[5]	85	99	95	100
	In-Service Capital – Distribution (% of Plan)[5]	87	97	95	100

1 New measures are in bold.

2 2015 targets are based on historical data, benchmarking (where available) and approved Business Plans. Targets reflect the Company's strategic objectives and consideration of the audited 2014 year-end results for review and approval by the accountable Executive and Hydro One Committees and Board.

3 Safety, including major safety events, will be an important consideration of the Board in determining the level of short term incentive pool.

4 The Customer satisfaction measures have moved away from measuring top-line customer satisfaction and instead shifted to measuring satisfaction with relevant business processes and transactional customer experience. The Distribution Customer Satisfaction measure also includes an additional transactional survey called "My Account".

5 The targets do not reflect the impact of the Distribution Rate decision. Targets will be updated once the 2015 Business Plan and Gross Fixed Assets numbers are released.

Executive Summary

2016 Team Scorecard					
	Weight	Threshold	Target	Maximum	Description
Net Income	**50%**	582.2	685.0	736.0	$M
Customer Sat.	**20%**	74%	75%	80%	% Customer Satisfaction
Work Program	**20%**	97%	101%	106%	% Work Program Complete
Safety*	**10%**	1.7	1.6	1.5	Recordable Rate per 200,000 Hrs.
** If the company has a fatality, the attained Safety measure will be reduced by 50% based on the findings of the System Investigation*					

The 2016 Team Scorecard is developed to provide feedback that helps ensure the Company remains on track to achieving its Strategic Objectives.

The Team Scorecard is made up of four weighted measures (with a minimum of 10% given to any one measure) with the majority weighting on the financial measure.

The 2016 Team Scorecard is a key input into 2016 Management Compensation, specifically the Short Term Incentive Plan (STIP) Fund, as it relates to overall corporate performance in 2016.

Each Scorecard measure includes performance expectations expressed as Threshold/Target/Maximum to provide clear expectations at the Company level that can be translated into personal expectations for achievement.

Team Performance, expressed by the Team Scorecard, plays an increasingly larger role in Management Compensation based on level.

Bank	Team Weighting	Individual Weighting
Sr. Exec. (1-2)	80%	20%
Exec. (3-4)	80%	20%
Director (5)	70%	30%
Mgmt./Prof. (6-7)	70%	30%
Support (8-10)	50%	50%

The combination of these four performance measures are expected to drive the following behaviours:

1. A focus on finding ways to maximize net earnings without compromising work program delivery.
2. Focusing the organization on achieving activities that are meaningful and impactful to customers, in addition to continuing the focus on ensuring positive transactional outcomes.
3. Making it clear to the organization that an appropriate balance between satisfying all stakeholders, including ratepayers, shareholders and customers is the path to maximizing value.
4. Reinforcing the continuing importance of safety to the organization.
   NOTE: This metric has a modifier attached to it, which will require that, in the case of a fatal incident, the overall safety measure will be reduced by 50%. This appropriately demonstrates a fatality on our watch is unacceptable and must be heavily weighted.

School Energy Coalition Interrogatory # 3

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

Interrogatory:

Please provide a copy of all benchmarking analysis, reports, opinions and/or assessments, undertaken by Hydro One or for Hydro One since 2014, regarding any aspect that directly or indirectly relates to its distribution business that is not already included in this application.

Response:

Hydro One has provided two studies as attachments to this response.

Attachment 1	Willis Towers Watson - Hydro One PWU Benchmarking
Attachment 2	CEA – 2016 Electric Power System Reliability Assessment

Hydro One
PWU Benchmarking

Willis Towers Watson

Segmented Workforce Philosophy

Comparator Group Approach and Criteria

Hydro One's comparator groups have been differentiated to reflect the segmented labour markets for talent, i.e., Operations and Core Services roles, and will be applied consistently for the following employee groups to ensure a consistent end-to-end approach for understanding market position holistically:

- Executives
- Management Group
- PWU represented roles
- Society represented roles *(benchmarking has yet to commence)*

	Segment Definition	Comparator Group Selection Criteria
Operations	▪ Requires specific education, skills and knowledge in a professional area, directly related to concepts and methods associated with the transmission, distribution and regulation of power. Examples include: Operations, Engineering, Skilled Trades, Maintenance	▪ *Predominant focus on industry/nature of work*: reflects organizations where comparable specialized skill sets reside ▪ **Industry:** Utility ▪ **Geography:** Canada, with <30% Alberta representation ▪ **Size**: Revenue size > $500M ▪ **Ownership:** Balance of public and private-sector ownership models
Core Services	▪ Roles requiring education, skills and knowledge not specific to the transmission, distribution and regulation of power. Examples of such functions include Finance, Human Resources and Information Technology	▪ *Predominant focus on range of Ontario talent sources*: incorporates a variety of organizations based on labour market – assumes an Ontario labour market and recognizes the importance of Hydro One as an Ontario employer ▪ **Industry:** General Industry *(excluding subsidiary Retail and Consumer Products)* ▪ **Geography:** Ontario-based employers ▪ **Size**: Private sector: >$500M, Public sector: >$100M & Subsidiaries: >$1B ▪ **Ownership:** All structures

A detailed company listing of both peer groups are noted in Appendix I

Background and Context

Willis Towers Watson was engaged by Hydro One to benchmark its represented roles. This preliminary report provides competitive market data for Hydro One's PWU represented roles

Current Workforce Population Composition*

Hydro One Employee Group	Employee Distribution		Total 2016 Payroll Costs (in Millions)
	# of Employees	% of Total	
Management and Non-Represented Employees	762	7.4%	$105.6
Represented Employees (including Casual and Hiring Hall)	**9,569**	**92.6%**	**$806.6**
Total	10,331	100%	$912.2

PWU population accounts for approximately **80%** of the represented population. Society represents approximately **20%**

The represented population accounts for over **90%** of total Hydro One employees, accounting for **88%** of total 2016 payroll.

*Source: Hydro One 2016 Actual Payroll Summary
Society roles to be benchmarked at a later date

Background and Context

Willis Towers Watson benchmarked over 90% of Hydro One's PWU represented workforce in this review

Hydro One PWU workforce summary

PWU Segment	N count	% of PWU Incumbents benchmarked
Core Services	533	13%
Operations	3711	87%

Over **90%** of all PWU represented staff are in jobs included in the benchmarking analysis *(4244 of 4671)*

The prevalence of represented roles matched to Willis Towers Watson's compensation surveys varies significantly across the segmented peer groups

Peer Group Summary Statistics

Hydro One Peer Group	Prevalence of Annual Incentive Plan (AIP)*	% of unionized roles in the survey
Core Services	60%	9%
Operations	80%	56%

Broad-based AIP's are common among western-based utility comparators as a means to remain competitive with the oil & gas sector

Salary surveys are typically used as a means to review the competitiveness of an organization's non-represented workforce. A higher proportion of unionized roles are prevalent in the operations peer group (a reflection of the nature of work)

* Represents the percentage of peer companies offering a broad-based AIP *(levels below Management & Professional roles)*

Hydro One Salary Schedules

- PWU compensation is administered across a wide range of salary schedules that create internal equivalencies between jobs that are typically differentiated in the market place. Market benchmarking results provide some indication as to the differences

- At a high level, a summary of the typical titles and types of roles by schedule and by segment are summarized below:

PWU Schedule	Typical Titles by PWU Schedule
	Operations & Core Services
Schedule 20	Clerical/Technical/Technologist
Schedule 21	Helicopter Positions
Schedule 25	Trades
Schedule 26	Working Supervisors
Schedule 27	Motive Power Trades
Schedule 28	Regional Maintainers
Schedule 30	Controller/Dispatcher
Schedule 32	Trades - Services
Schedule 50	Certified Trades (other than civil trades)
Schedule 86/87	University/College Students

Benchmarking Methodology

- PWU job steps within each schedule have been matched to a comparable job within Willis Towers Watson's Compensation Database, based on segmented peer groups outlined on Page 2
- For the purposes of this internal exercise, an additional comparator group is used for the Core Service segment which reflects the utility and energy sector companies used to assess operations jobs. This peer group is not aligned with the segmented compensation philosophy, nor does it reflect direct competitors for talent in Ontario for these roles. This perspective is provided as an additional data point, as it reflects a highly unionized sample
- The following pages outline market comparison as follows:
  - **Operations Segment** – aligned to the agreed operations peer group
  - **Core Services (Primary Comparison)** – aligned to the agreed core services peer group
  - **Core Services (Secondary Comparison)** – reflecting core services roles (i.e., clerical positions), assessed against companies in the Operations peer group
- All market data is presented on a base salary and total target cash compensation basis as follows:

Compensation Element	Hydro One	Market
Base salary	Actual base salary	Actual base salary
Total Target Cash Compensation	Actual base salary + actual share grant plan award *(target 2.7% of salary)*	Actual base salary + target incentive plan awards

Executive Summary

- Market Compensation benchmark results have been provided on a segmented basis for the benchmarked PWU roles, covering 90% of the PWU represented workforce

Competitive Analysis

- On an overall basis, Hydro One's target total cash is, on average positioned at market (within +/- 10%) of its 50th percentile target market reference

Hydro One Segment	% +/- Target Market Positioning		Employee Distribution
	Base Salary	Target Total Cash (TTC)	
Operations	-4%	-8%	87%
Core Services	63%	64%	13%
Overall	**9%**	**7%**	**100%**

Note: Overall market positioning represents an incumbent weighted average spanning both employee segments

Over **90%** of all PWU represented staff are included in the benchmarking analysis *(4244 of 4671 incumbents)*

Compensation Element	Hydro One	Market Data
Base salary	Actual base salary	Actual base salary
Total Target Cash Compensation	Actual base salary + actual share grant plan award *(target 2.7% of salary)*	Actual base salary + target incentive plan awards
Market data were sourced from Willis Towers Watson's 2017 General Industry and 2017 Energy Services, Middle Management, Professional and Support (MMPS) database		

Competitive Positioning

Detailed Summary by Schedule

PWU Schedule	Average Competitive Positioning vs. Market Median						Employee % Distribution	
	Operations & Core Services		Operations		Core Services (Primary)			
	Base Salary	Target Total Cash (TTC)	Base Salary	Target Total Cash (TTC)	Base Salary	Target Total Cash (TTC)	Operations	Core Services
Schedule 20	26%	25%	6%	5%	78%	77%	18%	8%
Schedule 21	-	-	-	-	-	-	0%	0%
Schedule 25	7%	-18%	7%	-18%	-	-	2%	0%
Schedule 26	-11%	-18%	-11%	-18%	-	-	4%	0%
Schedule 27	-15%	-14%	-15%	-14%	-	-	2%	0%
Schedule 28	-12%	-14%	-12%	-14%	-	-	36%	0%
Schedule 30	-	-	-	-	-	-	3%	0%
Schedule 32	43%	47%	-	-	43%	47%	0%	2%
Schedule 50	-2%	-5%	-11%	-16%	45%	46%	22%	3%
Schedule 86	-	-	-	-	-	-	0%	0%
Schedule 87	-	-	-	-	-	-	0%	0%
Overall	9%	7%	-4%	-8%	63%	64%	87%	13%

Hydro One PWU workforce summary

PWU Segment	N count	% of PWU Incumbents benchmarked
Core Services	533	13%
Operations	3711	87%

Appendix I

Comparator Groups by Segment

Peer Group – Operations

For roles requiring an industry focus

Utilities Peer Group (n=21)		
Alberta Electric System Operator	Emera Inc.	NB Power
AltaLink	Enbridge Inc.	Nova Scotia Power
ATCO Ltd.	ENMAX Corporation	Ontario Power Generation
BC Hydro Power & Authority	EPCOR Utilities Inc.	Spectra Energy Transmission
Bruce Power LP	FortisAlberta Inc.	Toronto Hydro
Capital Power Corporation	GE Energy	TransAlta Corporation
Corix Group of Companies	Hydro Quebec	TransCanada Corp.

Percentile Statistics	Revenue	Assets
25th Percentile	$1,568,050,000	$5,047,225,000
50th Percentile	$2,801,000,000	$10,052,937,500
75th Percentile	$4,965,000,000	$29,830,750,000
Hydro One	**$6,500,000,000**	**$25,300,000,000**
Percentile Positioning	86P	72P

Ownership Structure	% of Total
Government Agency	38%
Public Parent	28%
Wholly Owned Subsidiary	24%
Joint Venture	5%
Private Parent	5%

Peer Group – Core Services
General industry focus

Core Service Peer Group (n=93)			
AIG Insurance Company of Canada	CPP Investment Board	Johnson and Johnson Canada	RGA Canada
Air Canada	Eaton Canada	Kinross Gold	RioCan Real Estate Investment Trust
Algonquin Power and Utilities Corp.	Economical Insurance	LifeLabs	Rogers Communications
Allstate Insurance Company of Canada	Element Fleet Management	Loblaw Companies Limited	Royal Bank of Canada
Aviva Canada Inc.	Export Development Canada (EDC)	LoyaltyOne Co.	RSA
Avnet International Canada	Facebook, Inc. (Canada)	MacDonald, Dettwiler and Associates Ltd.	Samuel Son and Co.
Bank of Montreal	FCA Canada Inc.	Magna International Inc.	Scotiabank
Bayer Inc.	Ford Motor Company of Canada, Limited	Manulife Financial Corporate	Stantec Inc.
Bell Canada	Four Seasons Hotels and Resorts	Maple Leaf Foods	Sun Life Financial
Bunge Canada	GE Aviation Canada	McCain Foods Limited	TD Bank Financial Group
Canada Post Corporation	General Dynamics Land Systems - Canada	Microsoft Canada	TELUS Corporation
Canadian Imperial Bank of Commerce	General Electric Canada	Molson Coors Canada	The Co-operators Group Limited
Canadian Natural Resources Ltd.	Gerdau Long Steel North America	Munich Reinsurance Company of Canada	The Empire Life Insurance Company
Canadian Nuclear Laboratories	Gordon Food Service Canada	NAV Canada	TMX Group Limited
Canadian Tire Corporation	Great Canadian Gaming Corp.	Nissan Canada, Inc.	Toronto Hydro
Canadian Tire Financial Services	Great-West Lifeco Inc.	Northbridge Financial Corporation	Travelers Insurance Company of Canada
Capital One Canada	Holt Renfrew	Novelis Inc.	Treasury Board of Canada Secretariat
CBC/Radio Canada	Home Capital Group	Ontario Power Generation	Univar Canada
Celestica Inc.	HP Canada Co.	Ontario Teachers' Pension Plan	University Health Network
CH2M Hill Canada	Husky Injection Molding Systems Ltd.	Parmalat Canada	VIA Rail Canada Inc.
Chubb Insurance Company of Canada	Independent Electricity System Operator	PepsiCo Canada	Workplace Safety & Insurance Board
City of Mississauga	Intact Financial Corporation	Pfizer Canada Inc.	
CNH Industrial Canada	Investors Group Inc.	Purolator Inc.	
Compass Group Canada	John Deere Canada ULC	Revera Inc.	

Percentile Statistics	Revenue	Assets
25th Percentile	$1,201,145,500	$2,500,773,000
50th Percentile	$2,271,811,000	$8,020,730,000
75th Percentile	$7,984,113,000	$28,188,750,000
Hydro One	**$6,500,000,000**	**$25,300,000,000**
Percentile Positioning	73P	74P

2016

Service Continuity Data on Distribution System Performance in Electrical Utilities

Electric Power System Reliability Assessment

www.electricity.ca

Acknowledgements

The Canadian Electricity Association gratefully acknowledges the support of the participant utilities whose data was used in the preparation of this report. We also wish to thank the Service Continuity Committee (SCC) for their support and guidance throughout the year.

Participation

If your utility is interested in participating in the Service Continuity Committee, please contact CEA at the contact information shown below.

Version Control

Document release date: June 5, 2017

This document supersedes all earlier versions.

This document is considered: FINAL

Canadian Electricity Association
Contact: Daniel Gent
gent@electricity.ca
www.electricity.ca

INTRODUCTION

This report presents the results of the fifty-fourth consecutive survey of the performance of the Distribution Systems in electrical utilities. The report, prepared by the Canadian Electricity Association (CEA), presents a statistical summary of the Distribution Systems Performance for the year 2016 and compares it to 2015, as well as to the 2012-2016 five-year average.

The report presents some industry standard metrics for the Electricity Distribution including:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- Index of Reliability (IOR)
- Customer Interruptions per Kilometre (CIKM)
- Customer Hours per Kilometre (CHIKM)

By using the above metrics in combination with the cause of an electricity interruption, utility companies can

- set targets for improvement
- develop programs in support of their improvement targets
- make design/build decisions that try to mitigate interruption causes

Major Event Days (MEDs) are included in all statistics within this report. Major Event Days -- also referred to as Most Prominent Events -- events that exceed reasonable design and or operational limits of the electric power system.

National significant events (or catastrophic events) are a subset of MEDs. These are generally events that are larger than most MEDs, are outside the control of the utility, and have an impact on the national composite statistics. These are evaluated on a case-by-case basis by the Service Continuity Committee.

Members of the Service Continuity Committee and participants in the Service Continuity program follow a systematic procedure for collecting and analyzing data with regard to the Distribution System Performance according to definitions set by the Committee. This procedure follows the guidelines set out by CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system continuity statistics for the entire electricity system. This includes the statistics captured in this report for the Distribution system and also statistics captured in the Bulk Electric System (BES) for service interruptions within the Transmission system. The EPSRA program is governed by the Consultative Committee on Outage Statistics (CCOS). The CCOS Committee was chaired until early 2010 by Dr. Roy Billinton of the University of Saskatchewan, a world renowned expert in the field of Electricity Equipment and Systems Reliability. The mission and vision of the Service Continuity Committee is below:

Mission:
Provide a mechanism to collect, analyze and report system distribution outage data, processes and functions in order to encourage members to gain and share insights and benefits through a community of practice.

Vision:
To be recognized as a trusted forum in distribution reliability practices through shared experiences and data analysis.

Objectives:

- Act as governing body that will oversee changes and enhancements of the database application and the data itself, while ensuring a high level of data quality/integrity.
- Act as distribution experts under the auspices of the CEA Analytics department and collaborate with the other Consultative Committee on Outage Statistics (CCOS) committees to share and present an overall view of Canadian electricity reliability.
- Actively perform/seek new research/analysis that will provide insight into enhancing distribution reliability.

- Add value to SCC members by providing a confidential forum for distribution system personnel to identify, develop and monitor the relevancy of distribution performance reliability measures, through shared practices, lessons learned and data analysis.
- Facilitate development of inter-utility networking for distribution system reliability.
- Maintain, update and provide guidance on common definitions and terms used in service continuity performance measurements, consistent with Canadian and International utility practices.
- Coordinate research efforts with other CEA groups as required.
- Be recognized nationally and internationally as a credible and trusted source for reliability information.

The membership of SCC includes one member of each of the participating CEA Corporate member utilities. It is chaired by Riaz Shaikh of PowerStream. The Vice-Chair is Betsy Matamoros of Fortis BC.

ACKNOWLEDGEMENT

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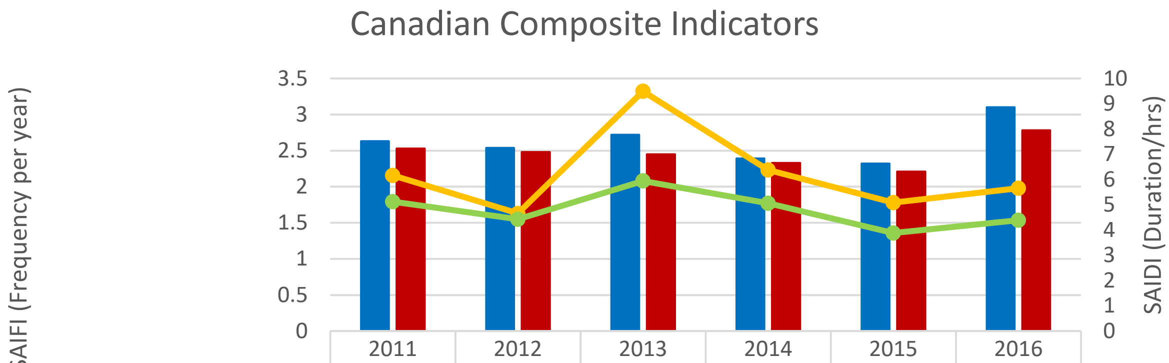
Yukon Electrical Co. Ltd.
Yukon Energy

Executive Summary

Service Continuity Committee (SCC) 2016 System Performance Report

Overview



	2011	2012	2013	2014	2015	2016
SAIFI	2.63	2.54	2.72	2.39	2.32	3.1
SAIFI (Significant Eventss Removed)	2.53	2.48	2.45	2.33	2.21	2.78
SAIDI	6.16	4.66	9.49	6.38	5.08	5.66
SAIDI (Significant Eventss Removed)	5.12	4.43	5.94	5.06	3.88	4.39

Highlights (all events):

- Tree Contacts contributed to 2 hours of the 5.66 SAIDI hours, they remain the largest contributor to SAIDI, the number of tree contacts has increased from 14% (2015) to 16% (2016) of interruptions or almost 10,000 interruptions, and 9,000,000 customer hours.
- Equipment Failure contributed to 0.85 hours of the 5.66 SAIDI hours, the 2nd largest contributor to SAIDI. Even though the SAIDI value was flat the number of interruptions due to equipment failures decreased slightly to 18.5% from 20% in 2015.
- The third largest contributor to SAIDI was Loss of Supply, contributing 0.57 hrs. This was a slight increase in interruptions from 2.6% to 2.9% (2016), however was a large increase in customer hours by almost 600,000 hours.

All Recorded Interruptions Summary				
Interruptions	Customer Interruptions	Customer Hours of Interruptions	SAIFI	SAIDI
292,906	44,929,125	82,127,861	3.10	5.66

Significant Events (SE) are those major events that the committee has deemed completely outside the control of the utility, and significantly impact the Canadian Index.				
Interruptions	Customer Interruptions	Customer Hours of Interruption	Contribution to Composite SAIFI	Contribution to Composite SAIDI
11,367	4,558,770	18,270,708	0.32	1.27

- Events classified as Significant Events, included two separate ice-storms, a lightning storm and the Fort McMurray fires. They represent 22% of the total hours of outages from 2016.

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1.0 DEFINITIONS

1.0 DEFINITIONS

1.1 DEFINITION OF TERMS

DISTRIBUTION SYSTEM

A Distribution System is that portion of an electric power system which links the Bulk Electricity System (BES) or sources with the customer's facilities.

Subtransmission lines, distribution substations, primary feeders, distribution transformers, secondaries and customers' services all form different parts of what can generally be called Distribution Systems. The Delivery Point (DP) is the delineation point between the BES and the Distribution System. It is the low voltage busbar of the step down transformer station, whereby the transformer busbar is considered part of the BES System. At the transformer station the voltage is stepped down from a transmission voltage, which may cover a range of 60-750kV to a distribution voltage of under 60kV.

Where the reporting company does not own the equipment up to the Delivery Point as defined above, the delineation point shall be at the point of ownership.

CUSTOMERS

The average number of customers served in the region during the reporting period. This means the number of customer services fed at secondary, primary and subtransmission voltages. A customer is defined as a metered service. Municipal utilities buying power from Provincial utilities should not be reported as customers by the Provincial utility.

INTERRUPTION

An *interruption* is the loss of service to one or more customers and is the result of one or more component outages. A *momentary interruption* is defined as an interruption with a duration of less than one (1) minute. These are interruptions generally restored by automatic reclosure facilities, which are of a very short duration (on the order of a few seconds).

INTERRUPTION-DURATION

This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

INTERRUPTION START TIME

An interruption is deemed to have occurred when the utility supplying power is made aware that a customer is without power. This is either the time the customer calls in or the time remote monitoring devices indicate a power interruption. It may be for either a full or part power interruption.

INTERRUPTION END TIME

An interruption is deemed to have ended when the utility supplying power is made aware that a customer's power has been restored. This is either the time the restoring crew reports the restoration is complete or the time remote monitoring devices indicate a power has been restored.

CUSTOMER-HOURS OF INTERRUPTION

This is the product of the customer services interrupted by the period of interruption.

CUSTOMER-INTERRUPTIONS

This is the sum of products of the customer services interrupted by the number of interruptions that affect those customer services.

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

This index is defined as the average number of interruptions per customer served per year.

$$\textbf{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (MOMENTARY) SAIFI (MI)

This index is defined as the average number of interruptions per customer served per year for momentary interruptions (interruptions of a duration less than 1 minute).

$$\textbf{SAIFI (MI)} = \frac{\text{Total Momentary Customer-Interruptions}}{\text{Total Customers Served}}$$

(in area where momentary interruptions are monitored)

SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

This index is defined as the system average interruption duration for customers served per year.

$$\textbf{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

This index is defined as the customer average interruption duration for customers interrupted during a year.

$$\textbf{CAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

CUSTOMER INTERRUPTIONS PER KM

$$\textbf{Customer Interruptions per KM} = \frac{\text{Customer Interruptions}}{\text{Circuit Km}}$$

CUSTOMER HOURS PER KM

$$\textbf{Customer Hours per KM} = \frac{\text{Customer Hours}}{\text{Circuit Km}}$$

INDEX OF RELIABILITY

The per unit of annual customer-hours that service is available.

$$\textbf{Index of Reliability} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

1.2 CLASSIFICATION OF INTERRUPTIONS BY CAUSE

A customer interruption has been defined in terms of primary cause of the interruption. These causes have been assigned the following codes:

0 - ***Unknown/Other***

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - ***Scheduled Outage***

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 - ***Loss of Supply***

Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.

3 - ***Tree Contacts***

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 - ***Lightning***

Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.

5 - ***Equipment Failure***

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 - ***Adverse Weather***

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 - ***Adverse Environment***

Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 - ***Human Element***

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.

9 - ***Foreign Interference***

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

2.0 PERFORMANCE OF UTILITIES

2.0 PERFORMANCE OF UTILITIES

2.1 COMPARISON OF 2016 CANADIAN SYSTEM INDICES TO 2015

SAIFI	The average number of interruptions per customer per year was 3.10, which represents an increase of 33.4% over the 2015 figure of 2.32.
SAIDI	The system average interruption duration for customers served was 5.66 hours per year, which represents an increase of 11.5% over the 2015 figure of 5.08 hours.
CAIDI	The average customer interruption duration per interruption was 1.83 hours, which represents a decrease of 16.4% over the 2015 figure of 2.19 hours.
Index of Reliability	or the per unit annual customer hours that service is available was 0.999354, as compared to 0.999420 in 2015.
CHIKM	The average customer hour interruptions per KM was 100.50, which represents an increase of 12.7% over the 2015 figure of 89.14.
CIKM	The average customer interruptions per KM was 54.98, which represents an increase of 34.9% over the 2015 figure of 40.75.

2.2 COMPARISON OF 2016 INTERNATIONAL SYSTEM INDICES TO 2015

SAIFI	The average number of interruptions per customer per year was 8.22, which represents an increase of 36.54% over the 2015 value of 6.02.
SAIDI	The system average of interruption duration for customers served was 15.28 hours per year, which represents an increase of 91.48% over the 2015 value of 7.98.
CAIDI	The average customer interruption duration per interruption was 1.86 which represents an increase of 40.91% over the 2015 value of 1.32.
Index of Reliability	The Index of Reliability was 0.998256, as compared to 0.999090 in 2015.
CHIKM	The average customer hour interruptions per KM was 423.5, which represents an increase of 39.87% over the 2015 value of 302.79.
CIKM	The average customer interruptions per KM was 227.70, which represents a decrease of 0.47% over the 2015 value of 228.78.

2.3 General Statistics Summary:

Canadian Utilities:

	2016	2015
Total Customers:	14,509,663	14,329,556
Total Distribution System Peak (KW):	77,578,797	89,056,407
Average Distribution System Peak (KW):	1,891,1657	2,283,498
Total Area Served (SQ.KM):	5,863,913	5,863,146
Total Distribution Circuit (KM) Overhead:	668,582	667,728
Total Distribution Circuit (KM) Underground:	148,579	149,025
Total Distribution Circuit (KM) Both:	817,161	816,753

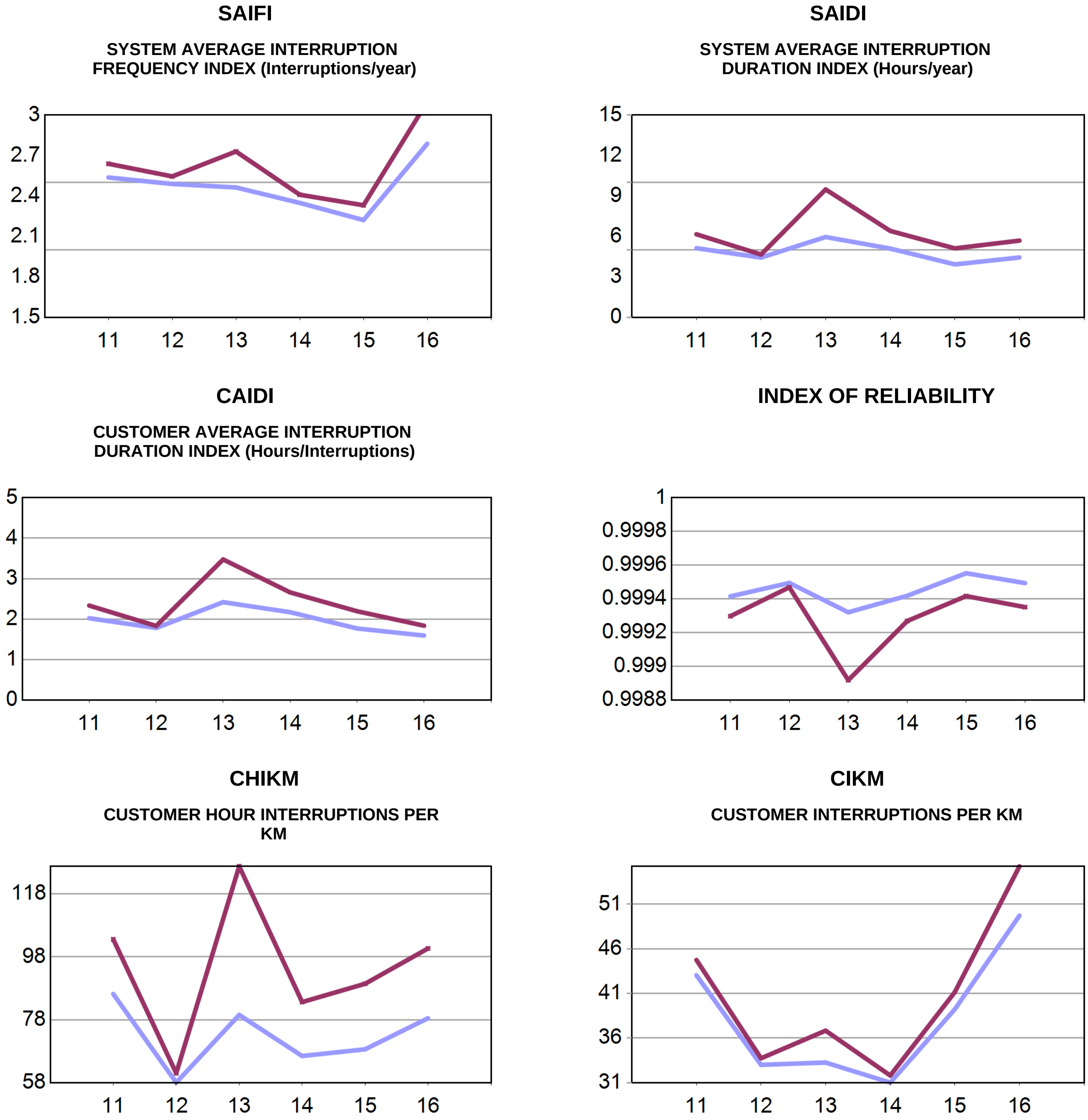
International Utilities:

	2016	2015
Total Customers:	276,529	361,737
Total Distribution System Peak (KW):	278,510	2,097,169
Average Distribution System Peak (KW):	564.2	349,528
Total Area Served (SQ.KM):	2,821	3,771
Total Distribution Circuit (KM) Overhead:	9127	4,721
Total Distribution Circuit (KM) Underground:	858	4,806
Total Distribution Circuit (KM) Both:	9985	9,527

Combined:

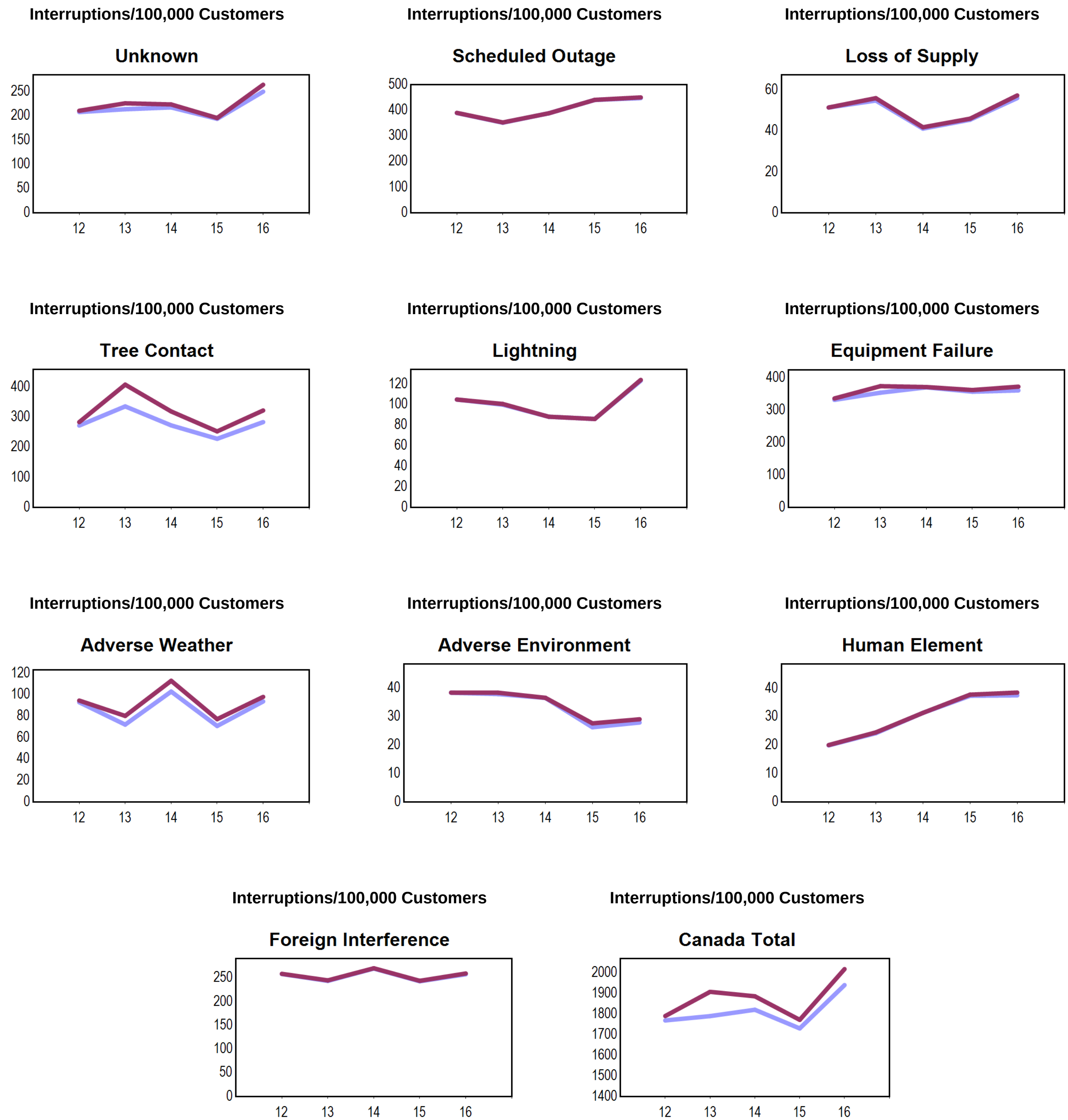
	2016	2015
Total Customers:	14,786,192	14,691,293
Total Distribution System Peak (KW):	77,854,332	91,153,576
Average Distribution System Peak (KW):	1,692,550	2,025,635
Total Area Served (SQ.KM):	5,866,734	5,866,917
Total Distribution Circuit (KM) Overhead:	677,709	672,449
Total Distribution Circuit (KM) Underground:	6,544,443	153,831
Total Distribution Circuit (KM) Both:	827,146	826,280

The annual variations in the service indices for Canadian data for the period 2011 to 2016 are shown below in Graph 2.1.



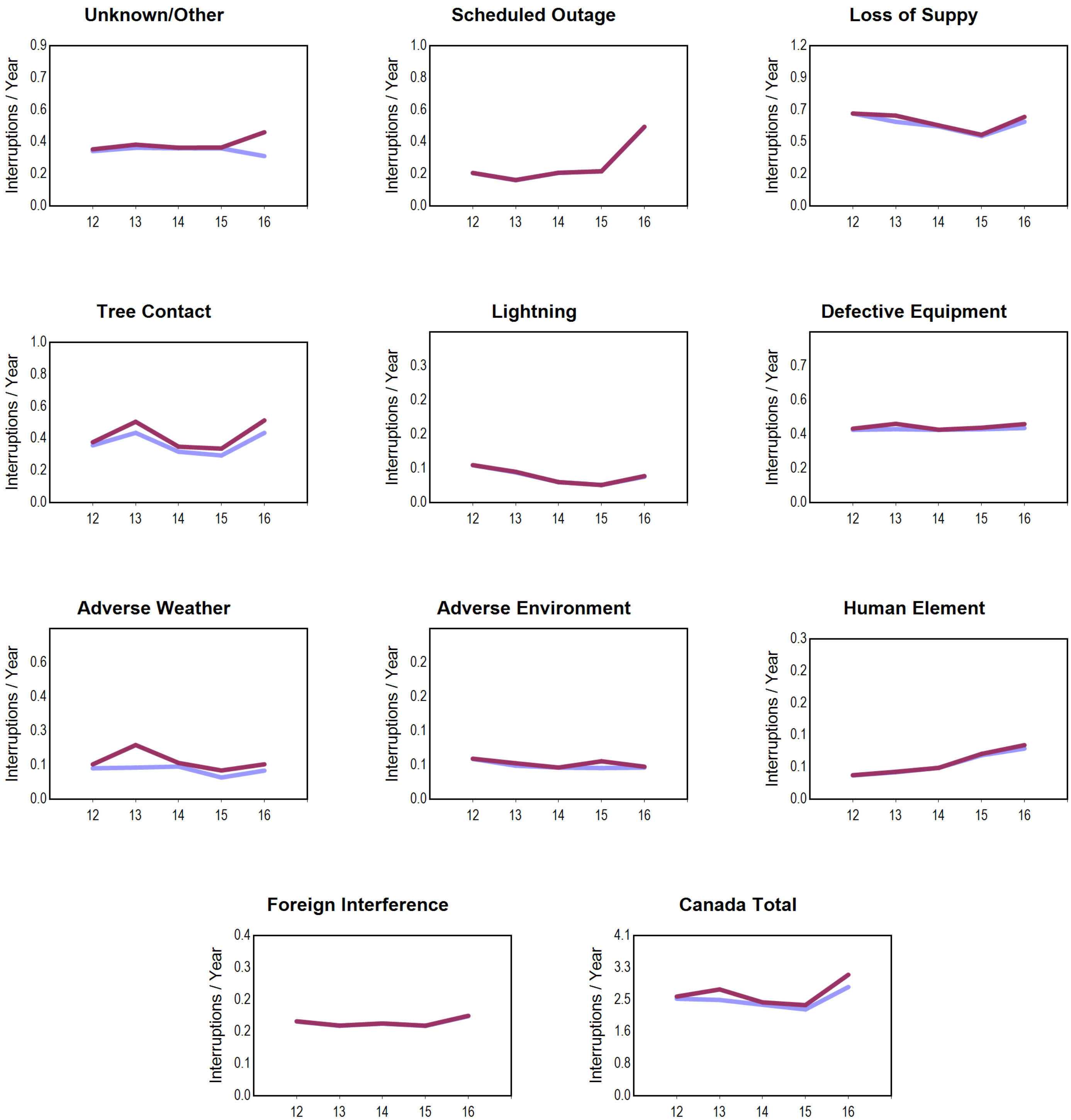
Note: denotes the exclusion of Significant Event data.

Graph 2-1 System Indices of SAIFI, SAIDI, CAIDI & IOR for 2011-2016 Canadian Data



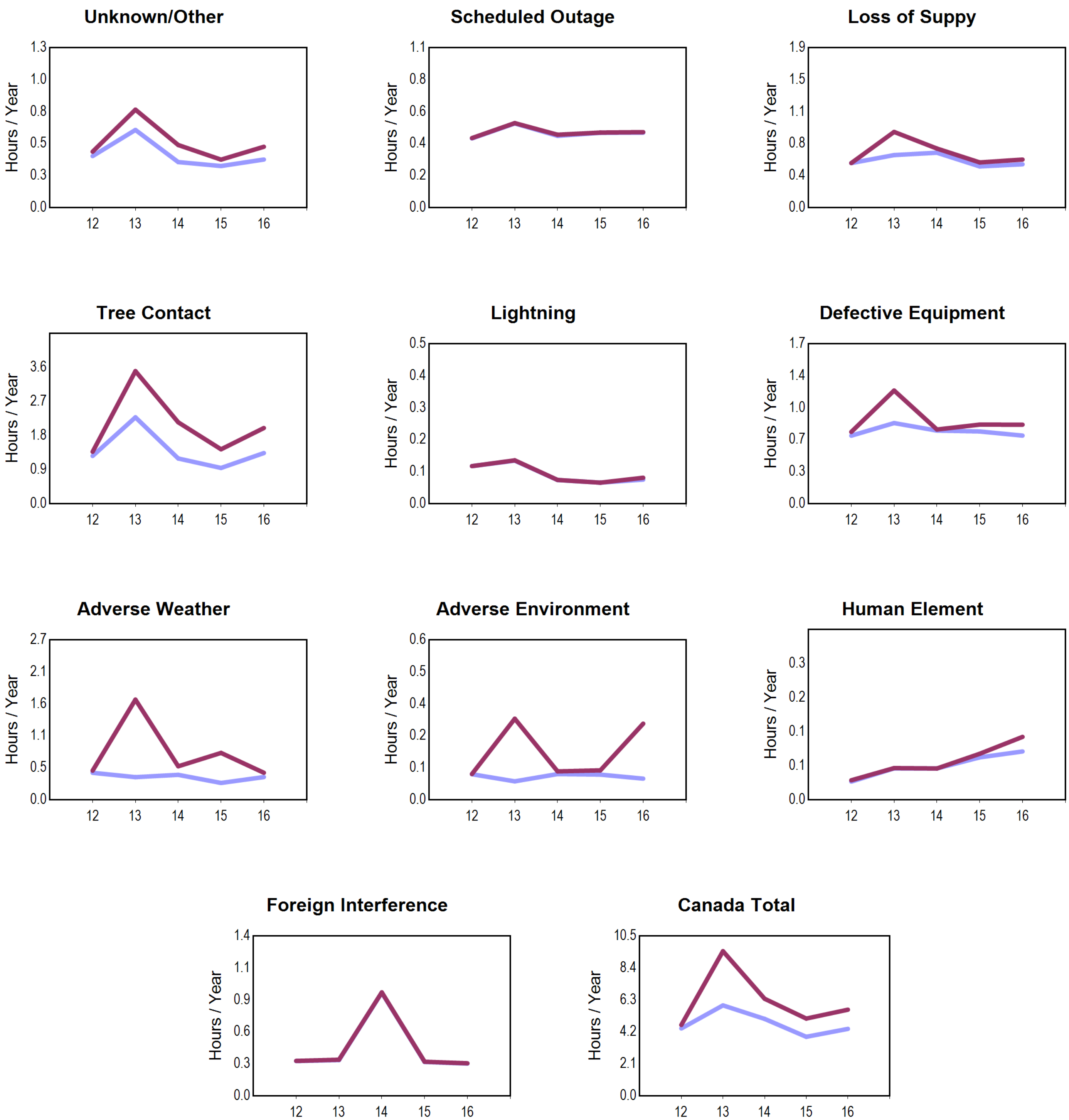
Note: ▬▬ denotes the exclusion of Significant Event data.

Graph 2-2 Causes of Interruptions for 2012-2016 Canadian Data - normalized to 100,000 customers



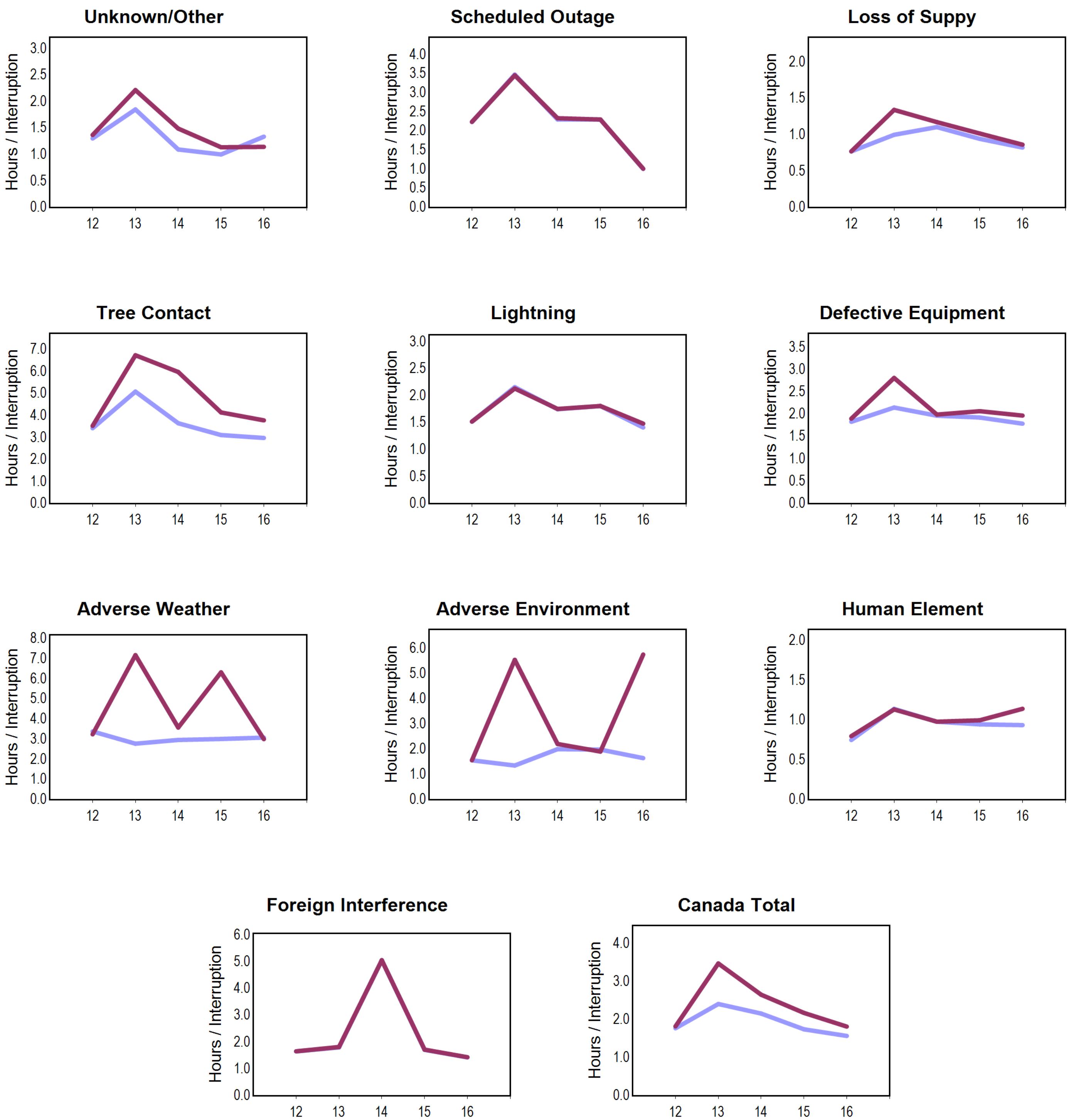
Note: denotes the exclusion of Significant Event data.

Graph 2-3 Contribution to SAIFI by Cause for 2012-2016 Canadian Data



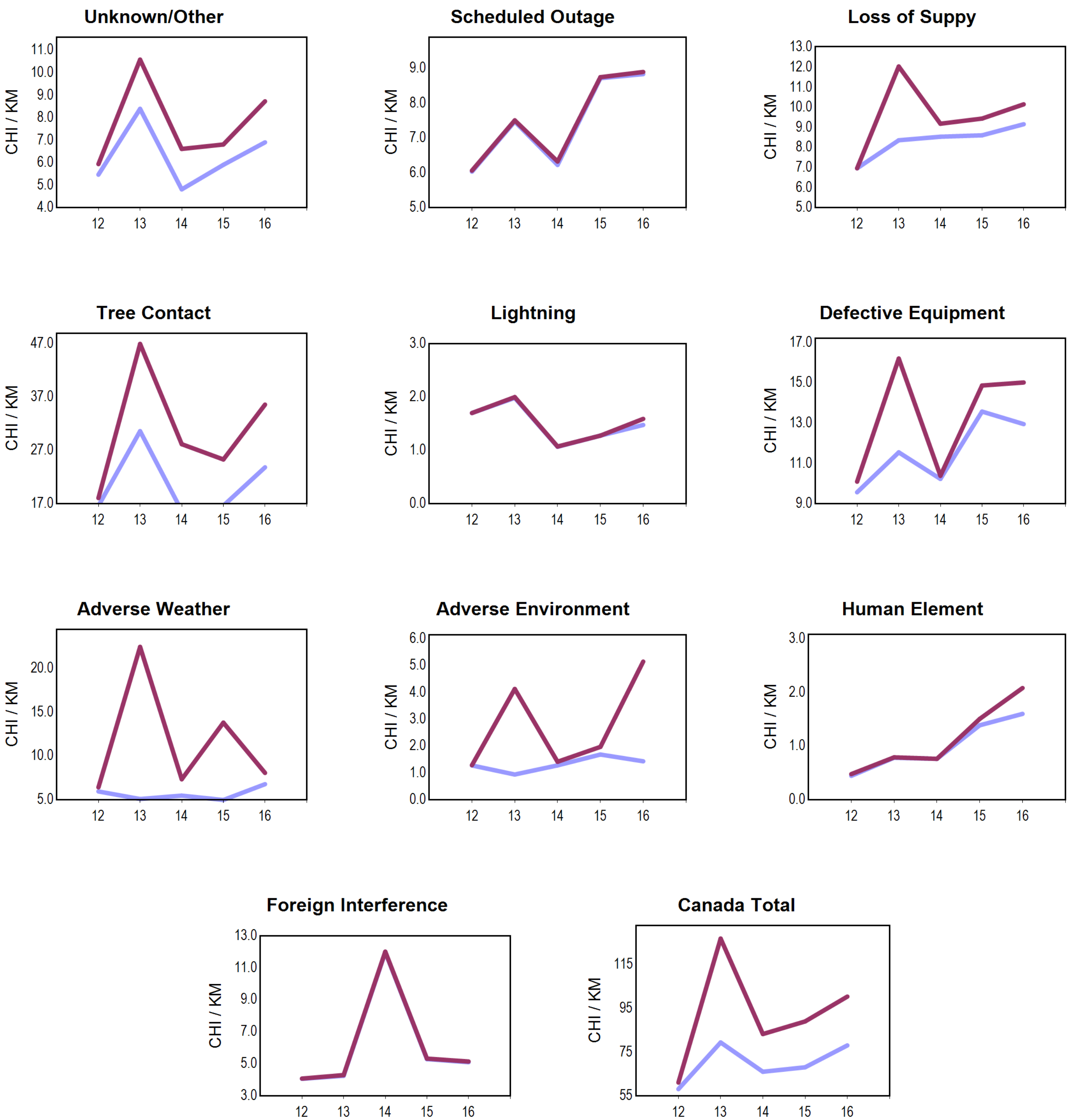
Note: denotes the exclusion of Significant Event data.

Graph 2-4 Contribution to SAIDI by Cause for 2012-2016 Canadian Data



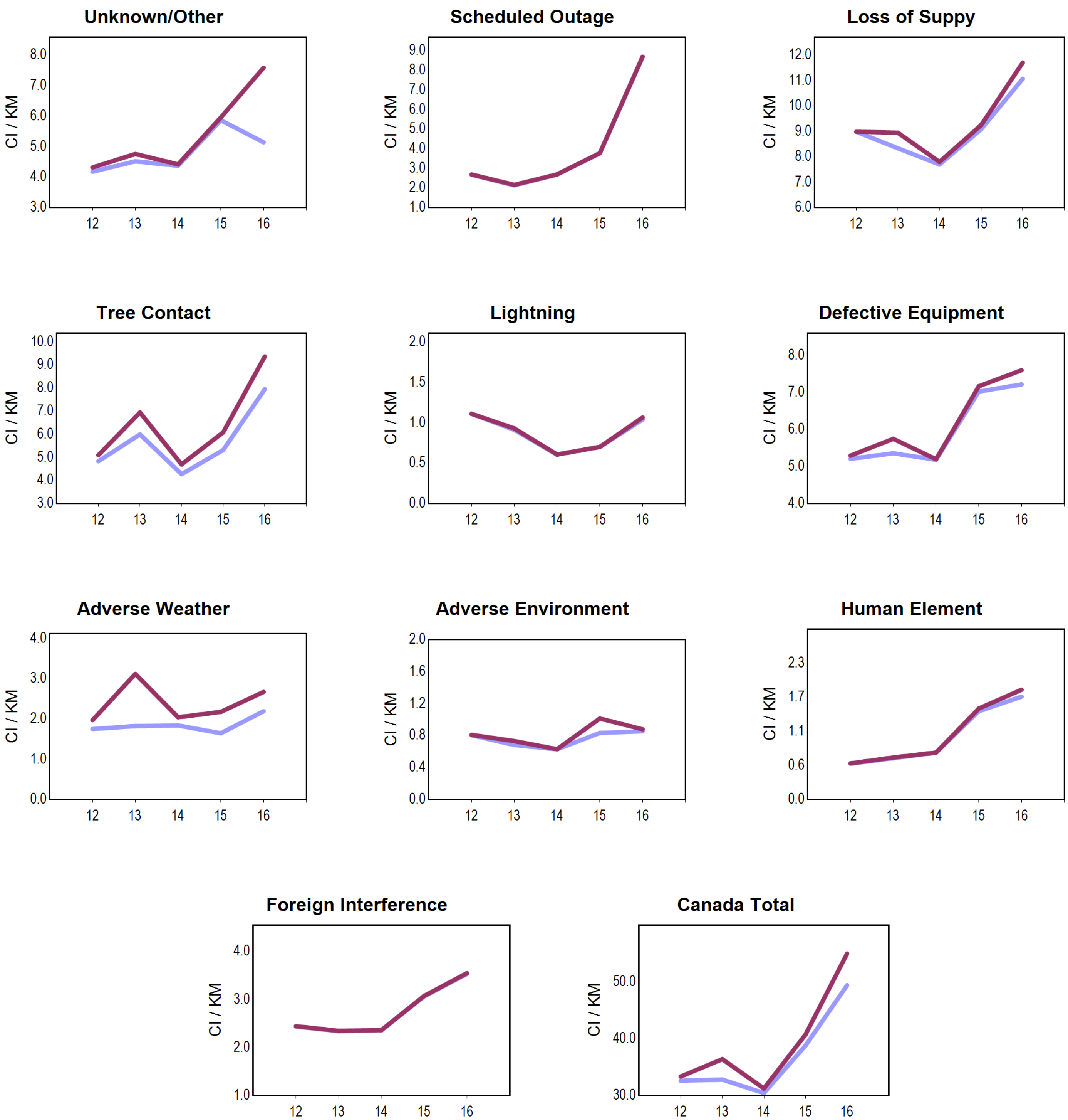
Note: denotes the exclusion of Significant Event data.

Graph 2-5 Contribution to CAIDI by Cause for 2012-2016 Canadian Data



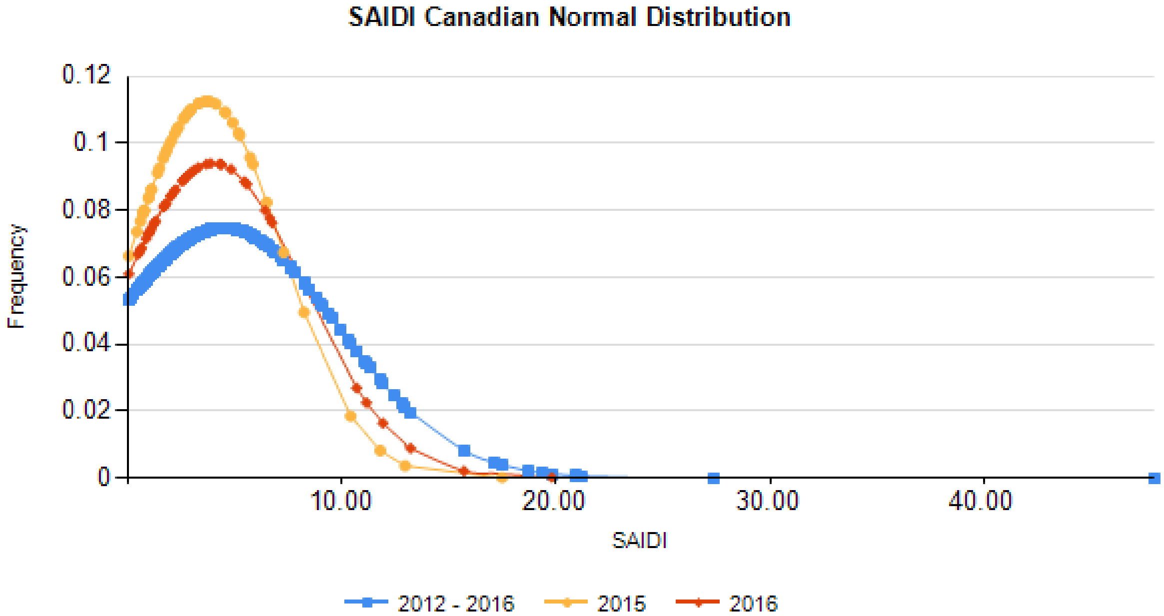
Note: denotes the exclusion of Significant Event data.

Graph 2-6 Contribution to CHIKM by Cause for 2012-2016 Canadian Data



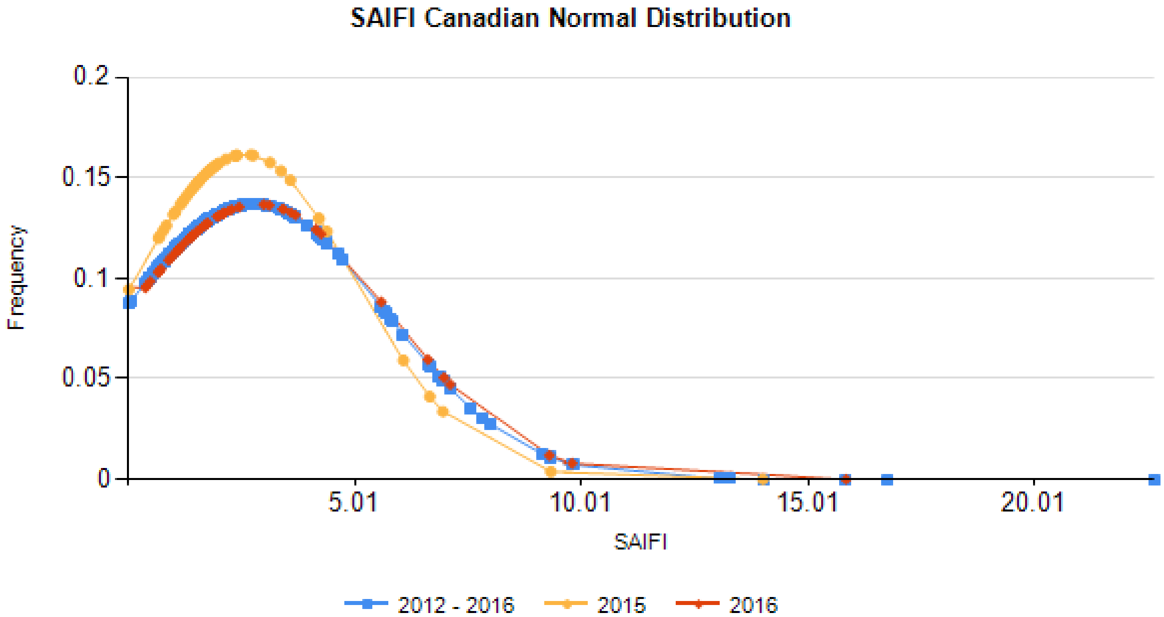
Note: denotes the exclusion of Significant Event data.

Graph 2-7 Contribution to CIKM by Cause for 2012-2016 Canadian Data



2016 SAIDI normal distribution confidence level: 95% 3.95 +/- 1.03

2016 SAIDI Standard Error 0.57



2016 SAIFI normal distribution confidence level: 95% 2.86 +/- 0.71

2016 SAIFI Standard Error 0.41

3.0 TABULATION AND ANALYSIS OF SERVICE INTERRUPTION DATA

TABLE 3-1

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2011 - 2016

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.
IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2016

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2011	13,166,791	247,330	34,640,048	81,099,286	115,341,089,160	0.999297
2011**	13,166,791	238,144	33,292,588	67,434,099	115,341,089,160	0.999415
2012	13,404,198	240,053	34,048,735	62,443,872	117,420,774,480	0.999468
2012**	13,404,198	237,178	33,295,600	59,383,340	117,420,774,480	0.999494
2013	13,737,830	262,160	37,393,115	130,409,957	120,343,390,800	0.998916
2013**	13,737,830	245,962	33,704,732	81,641,090	120,343,390,800	0.999322
2014	13,972,670	263,607	33,413,324	89,095,948	122,400,589,200	0.999272
2014**	13,972,670	254,488	32,560,856	70,666,529	122,400,589,200	0.999423
2015	14,321,390	253,821	33,247,310	72,732,010	125,455,376,400	0.999420
2015**	14,321,390	247,863	31,665,128	55,618,878	125,455,376,400	0.999557
2016	14,509,663	292,906	44,929,125	82,127,861	127,104,647,880	0.999354
2016**	14,509,663	281,539	40,370,352	63,857,155	127,104,647,880	0.999498

*** Excludes Significant Events*

INTERNATIONAL UTILITIES IN 2016

2011	160,859	6,898	919,580	737,138	1,409,124,840	0.999477
2012	106,299	2,924	718,946	751,786	931,179,240	0.999193
2013	585,553	16,734	3,083,530	3,743,124	5,129,444,280	0.999270
2014	787,143	19,769	6,597,349	5,656,404	6,895,372,680	0.999180
2015	361,737	2,420	2,178,927	2,884,883	3,168,816,120	0.999090
2016	276,529	2,447	2,273,771	4,224,430	2,422,394,040	0.998256
2016**	276,529	2,418	2,154,361	2,481,424	2,422,394,040	0.998976

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

TABLE 3-2

SYSTEM CAUSES OF SERVICE INTERRUPTION

FOR YEAR 2016

Canadian

14,509,663 CUSTOMERS IN 2016
14,321,390 CUSTOMERS IN 2015

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI	CHIKM	CIKM
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)		
Unknown/Other											
2016	38,384	13.1	6,202,046	13.8	7,140,281	8.7	0.43	0.49	1.15	8.74	7.59
2015	28,048	11.1	4,861,498	14.6	5,561,781	7.6	0.34	0.39	1.14	6.82	5.96
5 YEAR AVERAGE	31,407	12.0	5,017,274	13.7	7,342,642	8.4	0.36	0.52	1.46	7.73	5.28
Scheduled Outage											
2016	65,477	22.4	7,108,581	15.8	7,274,051	8.9	0.49	0.50	1.02	8.90	8.70
2015	63,241	24.9	3,088,320	9.3	7,140,992	9.8	0.22	0.50	2.31	8.75	3.79
5 YEAR AVERAGE	56,805	21.6	3,611,215	9.9	7,016,796	8.0	0.26	0.50	1.94	7.39	3.80
Loss of Supply											
2016	8,350	2.9	9,569,504	21.3	8,303,407	10.1	0.66	0.57	0.87	10.16	11.71
2015	6,610	2.6	7,547,355	22.7	7,710,151	10.6	0.53	0.54	1.02	9.45	9.25
5 YEAR AVERAGE	7,093	2.7	8,763,332	23.9	9,063,751	10.4	0.63	0.65	1.03	9.54	9.23
Tree Contacts											
2016	46,867	16.0	7,659,748	17.0	29,091,503	35.4	0.53	2.00	3.80	35.60	9.37
2015	36,277	14.3	4,968,953	14.9	20,659,014	28.4	0.35	1.44	4.16	25.32	6.09
5 YEAR AVERAGE	44,423	16.9	5,998,854	16.4	29,310,743	33.6	0.43	2.10	4.89	30.86	6.32
Lightning											
2016	18,014	6.2	873,627	1.9	1,301,101	1.6	0.06	0.09	1.49	1.59	1.07
2015	12,332	4.9	574,224	1.7	1,043,276	1.4	0.04	0.07	1.82	1.28	0.70
5 YEAR AVERAGE	14,119	5.4	839,107	2.3	1,456,574	1.7	0.06	0.10	1.74	1.53	0.88
Defective Equipment											
2016	54,103	18.5	6,212,250	13.8	12,280,405	15.0	0.43	0.85	1.98	15.03	7.60
2015	51,904	20.4	5,848,664	17.6	12,138,735	16.7	0.41	0.85	2.08	14.88	7.17
5 YEAR AVERAGE	50,896	19.4	5,785,496	15.8	12,497,304	14.3	0.41	0.89	2.16	13.16	6.09
Adverse Weather											
2016	14,221	4.9	2,186,308	4.9	6,606,817	8.0	0.15	0.46	3.02	8.09	2.68
2015	11,063	4.4	1,778,234	5.3	11,274,665	15.5	0.12	0.79	6.34	13.82	2.18
5 YEAR AVERAGE	12,956	4.9	2,274,490	6.2	11,076,588	12.7	0.16	0.79	4.87	11.66	2.39
Adverse Environment											
2016	4,226	1.4	729,476	1.6	4,212,058	5.1	0.05	0.29	5.77	5.15	0.89
2015	3,965	1.6	839,606	2.5	1,613,736	2.2	0.06	0.11	1.92	1.98	1.03
5 YEAR AVERAGE	4,753	1.8	770,949	2.1	2,582,899	3.0	0.06	0.18	3.35	2.72	0.81
Human Element											
2016	5,594	1.9	1,484,051	3.3	1,702,980	2.1	0.10	0.12	1.15	2.08	1.82
2015	5,417	2.1	1,227,977	3.7	1,231,523	1.7	0.09	0.09	1.00	1.51	1.51
5 YEAR AVERAGE	4,291	1.6	974,109	2.7	1,012,029	1.2	0.07	0.07	1.04	1.07	1.03
Foreign Interference											
2016	37,670	12.9	2,903,534	6.5	4,215,258	5.1	0.20	0.29	1.45	5.16	3.55
2015	34,964	13.8	2,512,479	7.6	4,358,139	6.0	0.18	0.30	1.73	5.34	3.08
5 YEAR AVERAGE	35,766	13.6	2,571,497	7.0	6,002,603	6.9	0.18	0.43	2.33	6.32	2.71
Total											
2016	292,906	100.0	44,929,125	100.0	82,127,861	100.0	3.10	5.66	1.83	100.50	54.98
2015	253,821	100.0	33,247,310	100.0	72,732,010	100.0	2.32	5.08	2.19	89.14	40.75
5 YEAR AVERAGE	262,509	100.0	36,606,322	100.0	87,361,930	100.0	2.62	6.24	2.39	91.98	38.54

TABLE 3-2A

SYSTEM CAUSES OF SERVICE INTERRUPTION
FOR YEAR 2016

International

276,529 CUSTOMERS IN 2016
361,737 CUSTOMERS IN 2015

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI	CHIKM	CIKM
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)		
Unknown/Other											
2016	335	13.7	225,223	9.9	219,475	5.2	0.81	0.79	0.97	21.98	22.55
2015	342	14.1	183,628	8.4	184,345	6.4	0.51	0.51	1.00	19.35	19.27
5 YEAR AVERAGE	1,416	16.0	594,982	20.0	365,980	10.6	1.41	0.86	0.62	35.03	56.95
Scheduled Outage											
2016	536	21.9	95,458	4.2	327,158	7.7	0.35	1.18	3.43	32.76	9.56
2015	815	33.7	81,637	3.7	291,241	10.1	0.23	0.81	3.57	30.57	8.57
5 YEAR AVERAGE	1,070	12.1	155,664	5.2	557,275	16.1	0.37	1.32	3.58	53.34	14.90
Loss of Supply											
2016	419	17.1	972,888	42.8	978,855	23.2	3.52	3.54	1.01	98.02	97.43
2015	286	11.8	770,353	35.4	441,691	15.3	2.13	1.22	0.57	46.36	80.85
5 YEAR AVERAGE	1,306	14.7	778,382	26.2	381,482	11.1	1.84	0.90	0.49	36.51	74.50
Tree Contacts											
2016	169	6.9	136,202	6.0	149,342	3.5	0.49	0.54	1.10	14.96	13.64
2015	130	5.4	128,272	5.9	95,156	3.3	0.35	0.26	0.74	9.99	13.46
5 YEAR AVERAGE	1,255	14.2	215,118	7.2	287,985	8.3	0.51	0.68	1.34	27.56	20.59
Lightning											
2016	118	4.8	68,343	3.0	53,639	1.3	0.25	0.19	0.78	5.37	6.84
2015	41	1.7	34,481	1.6	20,640	0.7	0.10	0.06	0.60	2.17	3.62
5 YEAR AVERAGE	141	1.6	111,963	3.8	88,794	2.6	0.26	0.21	0.79	8.50	10.72
Defective Equipment											
2016	520	21.3	374,131	16.5	467,678	11.1	1.35	1.69	1.25	46.83	37.47
2015	503	20.8	530,008	24.3	681,046	23.6	1.47	1.88	1.28	71.48	55.63
5 YEAR AVERAGE	1,910	21.6	581,929	19.6	729,566	21.1	1.37	1.72	1.25	69.83	55.70
Adverse Weather											
2016	90	3.7	155,310	6.8	1,772,125	41.9	0.56	6.41	11.41	177.46	15.55
2015	44	1.8	63,870	2.9	793,727	27.5	0.18	2.19	12.43	83.30	6.70
5 YEAR AVERAGE	81	0.9	89,405	3.0	573,852	16.6	0.21	1.36	6.42	54.92	8.56
Adverse Environment											
2016	44	1.8	22,840	1.0	40,397	1.0	0.08	0.15	1.77	4.05	2.29
2015	36	1.5	32,472	1.5	38,341	1.3	0.09	0.11	1.18	4.02	3.41
5 YEAR AVERAGE	612	6.9	72,717	2.4	83,911	2.4	0.17	0.20	1.15	8.03	6.96
Human Element											
2016	46	1.9	44,963	2.0	28,402	0.7	0.16	0.10	0.63	2.84	4.50
2015	65	2.7	113,108	5.2	107,153	3.7	0.31	0.30	0.95	11.25	11.87
5 YEAR AVERAGE	132	1.5	91,900	3.1	64,670	1.9	0.22	0.15	0.70	6.19	8.80
Foreign Interference											
2016	170	6.9	178,413	7.8	187,359	4.4	0.65	0.68	1.05	18.76	17.87
2015	158	6.5	241,098	11.1	231,543	8.0	0.67	0.64	0.96	24.30	25.30
5 YEAR AVERAGE	937	10.6	278,445	9.4	318,612	9.2	0.66	0.75	1.14	30.50	26.65
Total											
2016	2,447	100.0	2,273,771	100.0	4,224,430	100.0	8.22	15.28	1.86	423.04	227.70
2015	2,420	100.0	2,178,927	100.0	2,884,883	100.0	6.02	7.98	1.32	302.78	228.69
5 YEAR AVERAGE	8,859	100.0	2,970,505	100.0	3,452,125	100.0	7.01	8.15	1.16	330.41	284.31

4.0 SUMMARY

4.0 SUMMARY

- For the 2016 reporting year, based on data for 14.5 million customers in Canada and 0.3 million international customers, the system indices are the following:

Canadian		*Excluding SE**	*International*		*Excluding SE**
SAIFI	3.10	2.77	SAIFI	8.22	7.79
SAIDI	5.66	4.28	SAIDI	15.28	8.98
CAIDI	1.83	1.54	CAIDI	1.86	1.15
IOR	0.999354	0.999511	IOR	0.998256	0.998975
CHIKM	100.50	76.01	CHIKM	423.05	248.52
CIKM	54.98	49.26	CIKM	227.70	215.76

**SE - Significant Events*

Canadian Statistics

- The number of customers as compared to last year has remained relatively stable with a slight increase of 1.3%.
- Compared to the previous year, the total interrupted customer-hours increased by 11.4 %. (Derived from Table 3-1).
- The number of interruptions increased by 13.3 %. (Table 3-1).
- The total customer interruptions increased by 26.0 %. (Table 3-1).
- The customer average interruption duration index or the average restoration time for affected customers was 1.83 hours, compared to 2.19 hours for 2015. (Table 3-2).

- The five major causes of service interruption of utilities are: (Derived from table 3-2)

Canadian:

- Scheduled Outage 22.35%
- Defective Equipment 18.47%
- Tree Contacts 16.0%
- Unknown/Other 13.1%
- Foreign Interference 12.86%

International:

- Scheduled Outage 21.9%
- Defective Equipment 21.25%
- Loss of Supply 17.12%
- Unknown/Other 13.69%
- Foreign Interference 6.95%

Section 4.1 Major Event and Significant Event Summary

For the year 2016, Canadian Utilities identified Major Event Days.

All Recorded Major Events

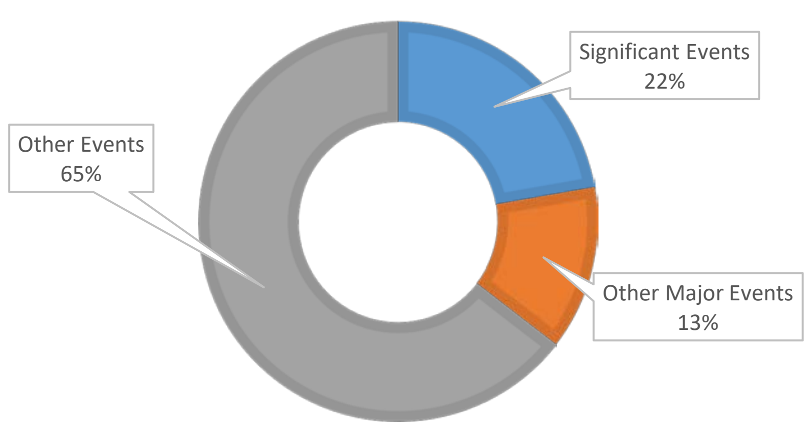
Year	Interruptions	Customer Interruptions	Customer Hours of Interruptions	Contribution to Composite SAIFI	Contribution to Composite SAIDI
2016	20,674	6,545,906	29,138,473	0.45	2.02
2015	13,059	3,737,677	26,234,850	0.26	1.83

Significant Events were determined from the recorded major event days. In 2016, those events are the following:

Significant Event Statistics

Event	Interruptions	Customer Interruptions	Customer Hours of Interruption	Contribution to Composite SAIFI	Contribution to Composite SAIDI
Ontario Ice Storm	3,148	598,963	5,724,264	0.04	0.40
Multi-Province Ice Storm	4,216	1,976,383	5,528,213	0.14	0.38
Quebec Lightning Storm	3,134	1,947,923	3,941,115	0.13	0.27
Fort McMurray Fires	869	35,501	3,077,116	0.00	0.21

CUSTOMER HOURS OF INTERRUPTION BREAKDOWN



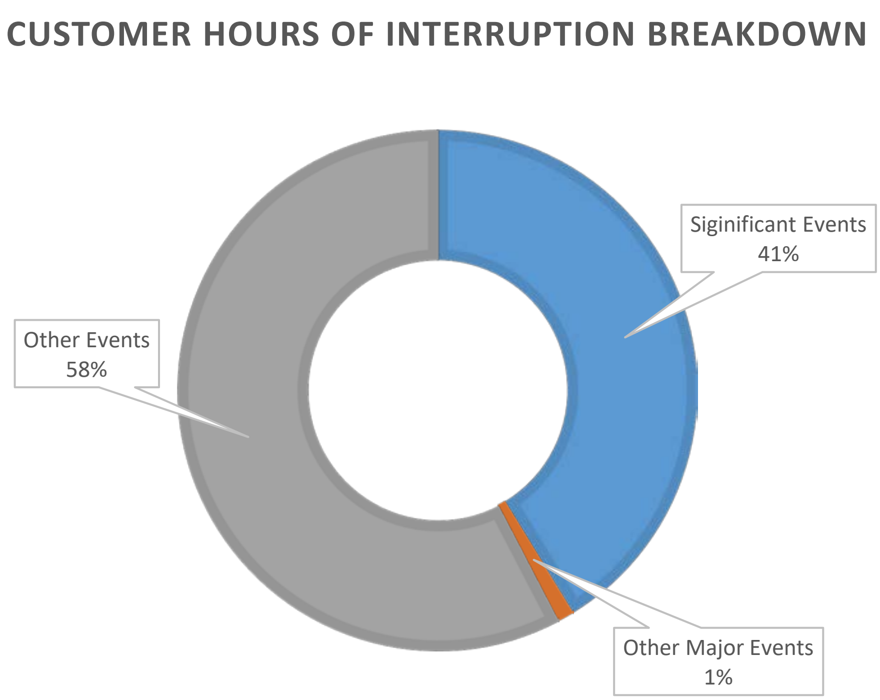
Section 4.2 International Major Event and Significant Event Summary

For the year 2016, International Utilities identified Major Event Days.

All Recorded Major Events					
Year	Interruptions	Customer Interruptions	Customer Hours of Interruptions	Contribution to Composite SAIFI	Contribution to Composite SAIDI
2016	48	318,301	1,786,808	1.15	6.46

Significant Events were determined from the recorded major event days. In 2016, those events are the following:

Significant Event Statistics					
Event	Interruptions	Customer Interruptions	Customer Hours of Interruption	Contribution to Composite SAIFI	Contribution to Composite SAIDI
Hurricane Matthew	29	119,410	1,743,006	0.43	6.3



5.0 SYSTEM CAUSES OF SERVICE OUTAGE

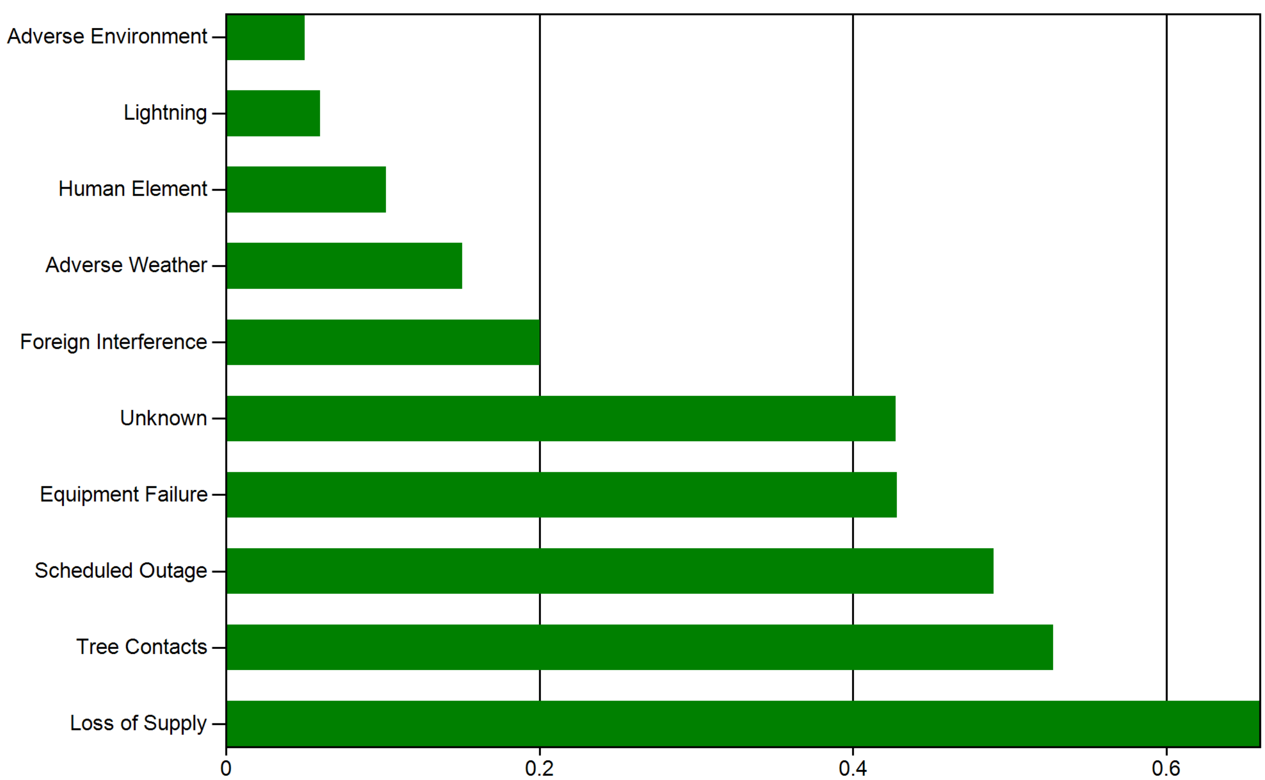
5.0 SYSTEM CAUSES OF SERVICE OUTAGE

SAIFI

Graphs 5-1 and 5-1a indicate the contributions to SAIFI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of interruptions attributed to each cause.

Canadian

	SAIFI	***% Interruptions***
Adverse Environment	0.05	1.4
Lightning	0.06	6.2
Human Element	0.10	1.9
Adverse Weather	0.15	4.9
Foreign Interference	0.20	12.9
Unknown	0.43	13.1
Equipment Failure	0.43	18.5
Scheduled Outage	0.49	22.4
Tree Contacts	0.53	16.0
Loss of Supply	0.66	2.9

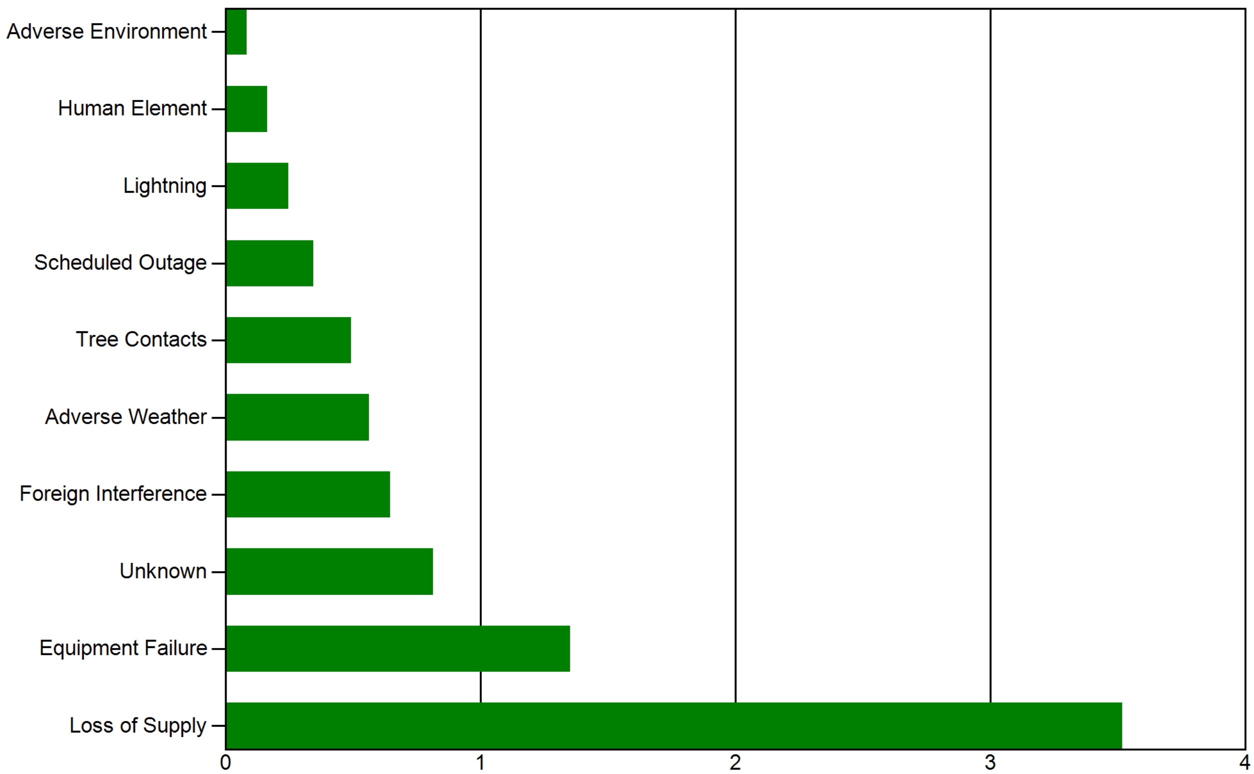


TOTAL SAIFI = 3.10

Graph 5-1 Contributions to SAIFI for 2016

International

	SAIFI	*% Interruptions*
Adverse Environment	0.08	1.8
Human Element	0.16	1.9
Lightning	0.25	4.8
Scheduled Outage	0.35	21.9
Tree Contacts	0.49	6.9
Adverse Weather	0.56	3.7
Foreign Interference	0.65	6.9
Unknown	0.81	13.7
Equipment Failure	1.35	21.3
Loss of Supply	3.52	17.1



TOTAL SAIFI = 8.22

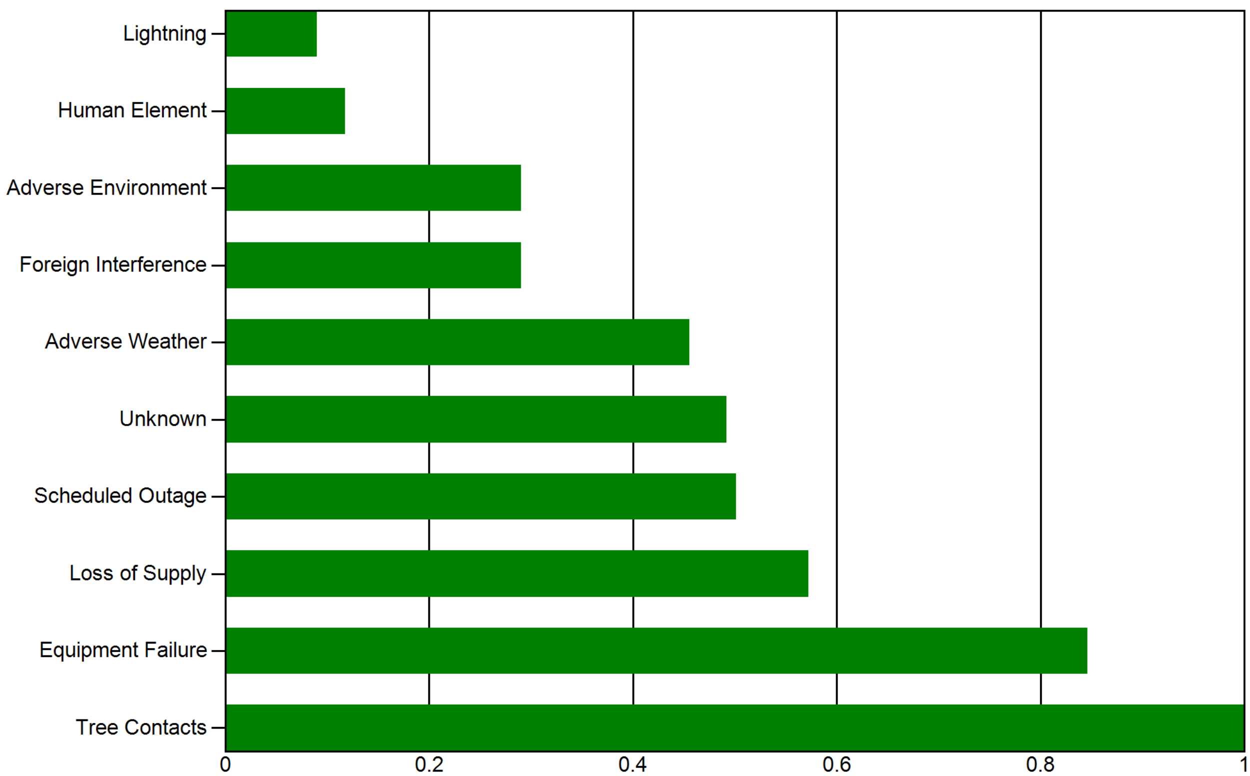
Graph 5-1a Contributions to SAIFI for 2016

SAIDI

Graphs 5-2 and 5-2a indicate the contributions to SAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruptions attributed to each cause.

Canadian

	SAIDI	*% Customer Interruptions*
Lightning	0.09	1.9
Human Element	0.12	3.3
Adverse Environment	0.29	1.6
Foreign Interference	0.29	6.5
Adverse Weather	0.46	4.9
Unknown	0.49	13.8
Scheduled Outage	0.50	15.8
Loss of Supply	0.57	21.3
Equipment Failure	0.85	13.8
Tree Contacts	2.00	17.0

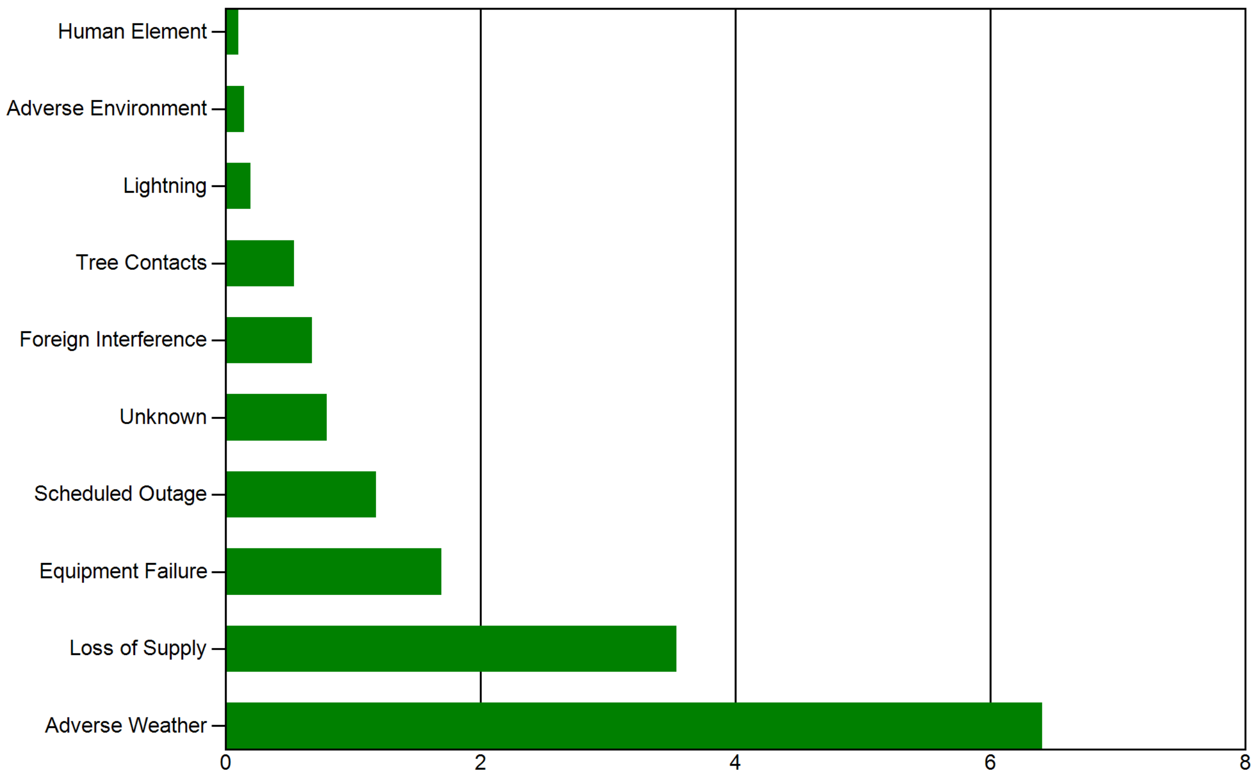


TOTAL SAIDI = 5.66

Graph 5-2 Contributions to SAIDI for 2016

International

	SAIDI	*% Customer Interruptions*
Human Element	0.10	2.0
Adverse Environment	0.15	1.0
Lightning	0.19	3.0
Tree Contacts	0.54	6.0
Foreign Interference	0.68	7.8
Unknown	0.79	9.9
Scheduled Outage	1.18	4.2
Equipment Failure	1.69	16.5
Loss of Supply	3.54	42.8
Adverse Weather	6.41	6.8



TOTAL SAIDI = 15.28

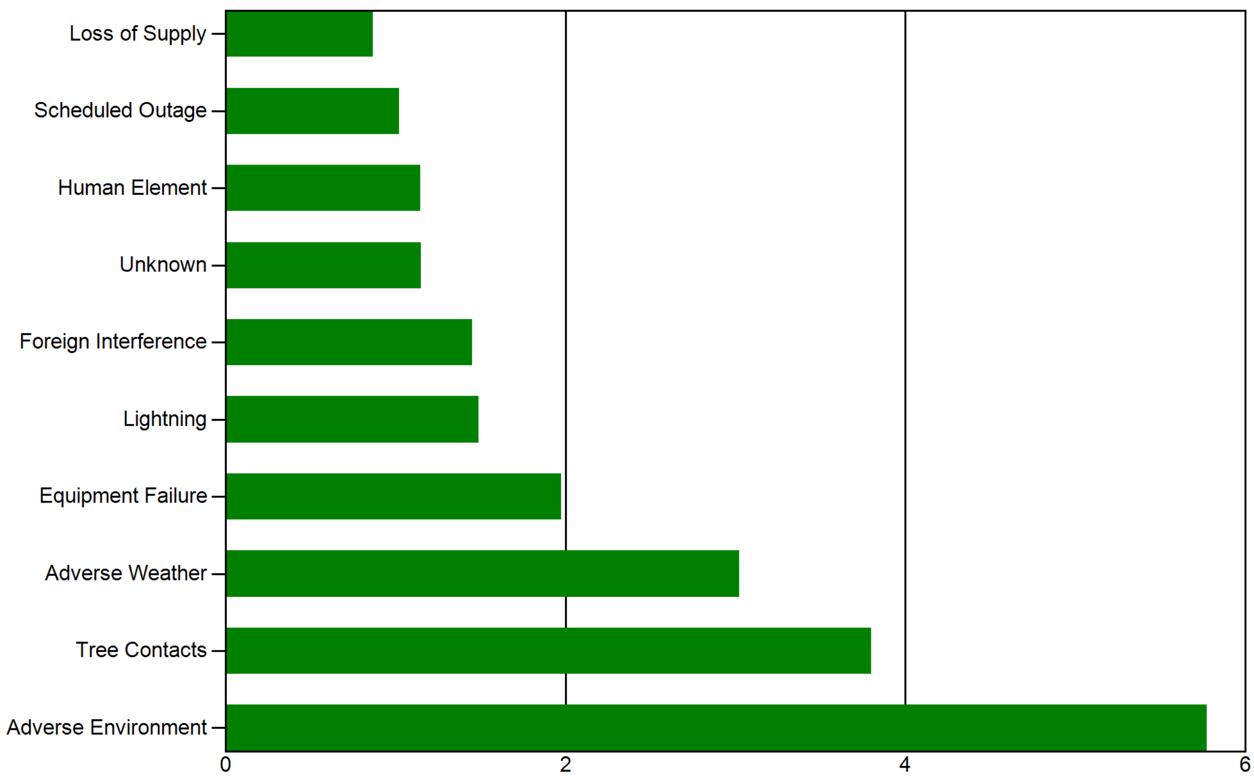
Graph 5-2a Contributions to SAIDI for 2016

CAIDI

Graphs 5-3 and 5-3a indicate the contributions to CAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption attributed to each cause.

Canadian

	CAIDI	*% Customer-hrs Interruptions*
Loss of Supply	0.87	10.1
Scheduled Outage	1.02	8.9
Human Element	1.15	2.1
Unknown	1.15	8.7
Foreign Interference	1.45	5.1
Lightning	1.49	1.6
Equipment Failure	1.98	15.0
Adverse Weather	3.02	8.0
Tree Contacts	3.80	35.4
Adverse Environment	5.77	5.1

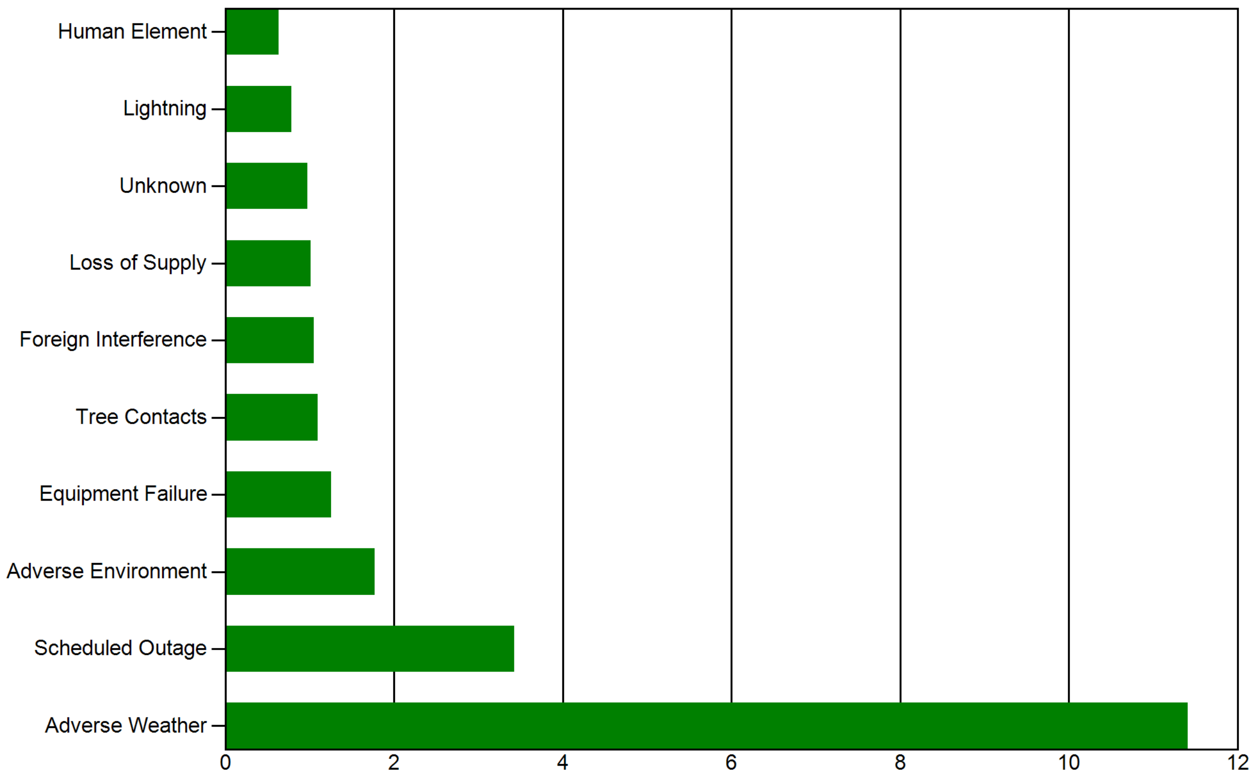


TOTAL CAIDI = 1.83

Graph 5-3 Contributions to CAIDI for 2016

International

	CAIDI	*% Customer-hrs Interruptions*
Human Element	0.63	0.7
Lightning	0.78	1.3
Unknown	0.97	5.2
Loss of Supply	1.01	23.2
Foreign Interference	1.05	4.4
Tree Contacts	1.10	3.5
Equipment Failure	1.25	11.1
Adverse Environment	1.77	1.0
Scheduled Outage	3.43	7.7
Adverse Weather	11.41	41.9



TOTAL CAIDI = 1.86

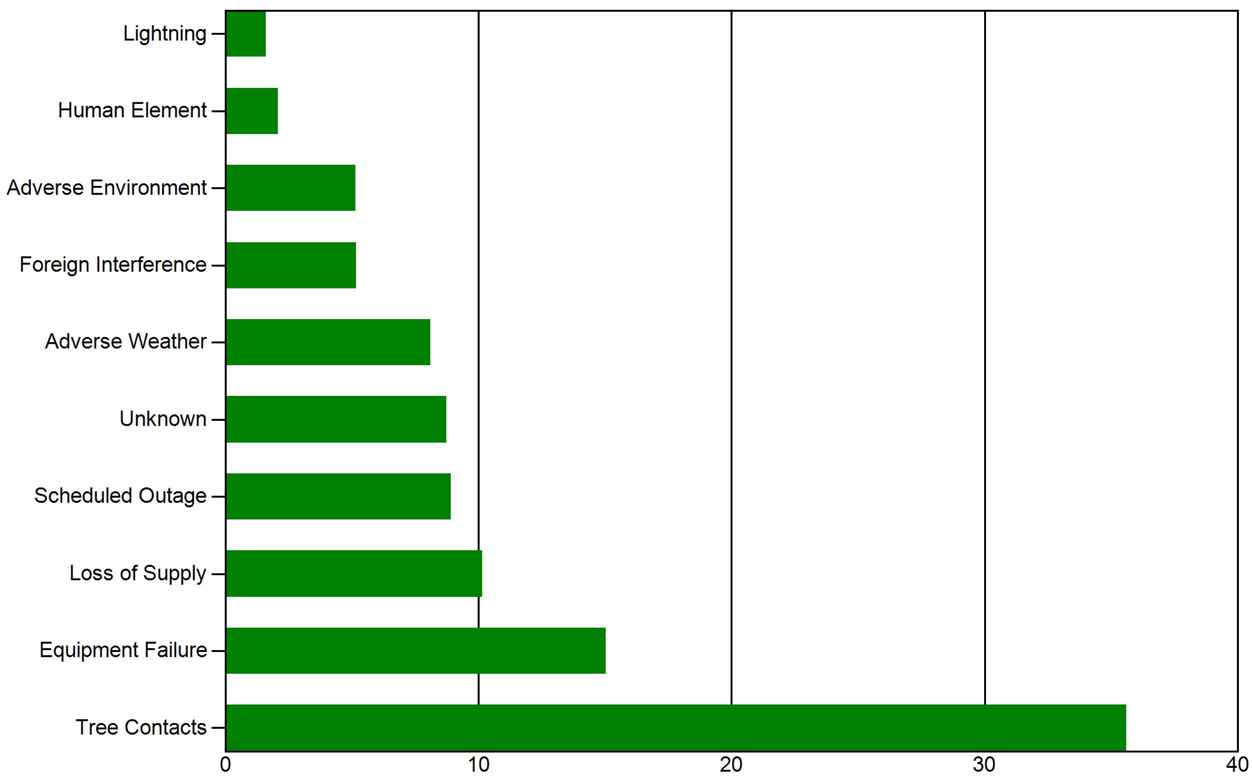
Graph 5-3a Contributions to CAIDI for 2016

CHIKM

Graphs 5-4 and 5-4a indicate the contributions to CHIKM for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption per circuit km attributed to each cause.

Canadian

	CHIKM	***% Customer-hrs Interruptions***
Lightning	1.59	1.6
Human Element	2.08	2.1
Adverse Environment	5.15	5.1
Foreign Interference	5.16	5.1
Adverse Weather	8.09	8.0
Unknown	8.74	8.7
Scheduled Outage	8.90	8.9
Loss of Supply	10.16	10.1
Equipment Failure	15.03	15.0
Tree Contacts	35.60	35.4

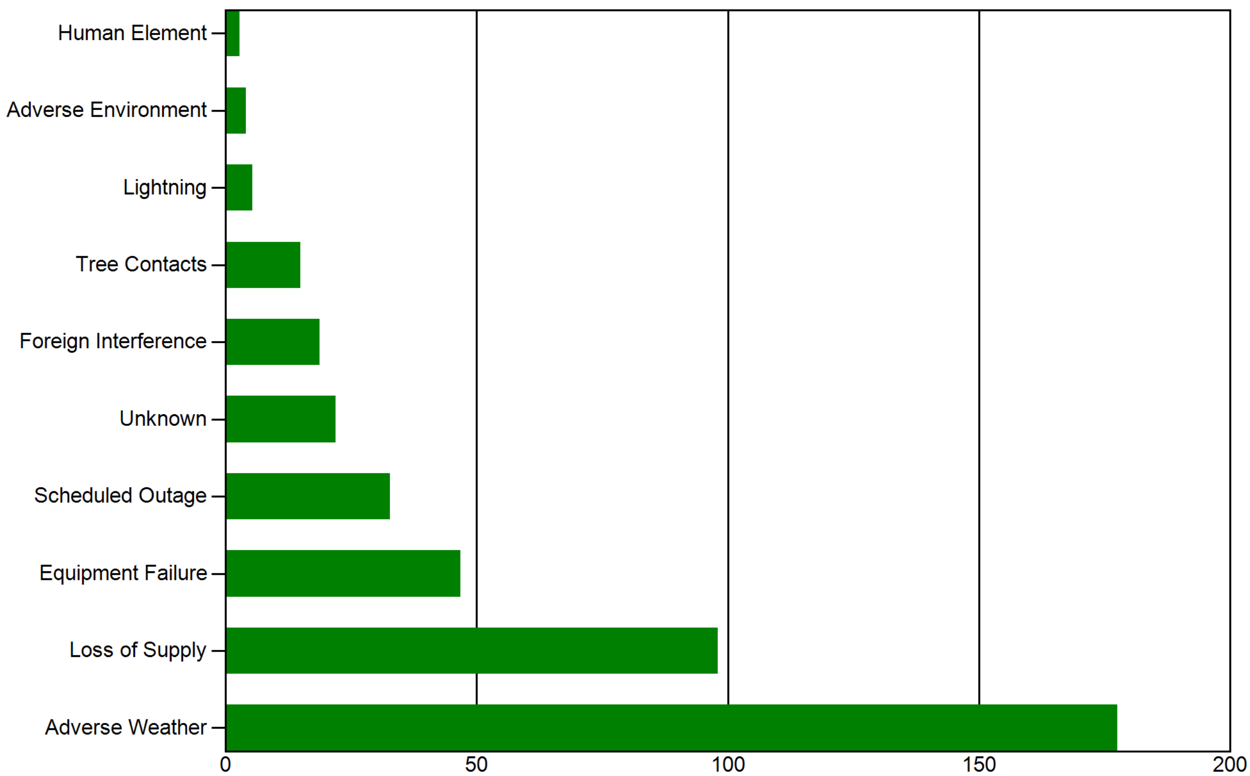


TOTAL CHIKM = 100.50

Graph 5-4 Contributions to CHIKM for 2016

International

	CHIKM	% Customer-hrs Interruptions
Human Element	2.84	0.7
Adverse Environment	4.05	1.0
Lightning	5.37	1.3
Tree Contacts	14.96	3.5
Foreign Interference	18.76	4.4
Unknown	21.98	5.2
Scheduled Outage	32.76	7.7
Equipment Failure	46.83	11.1
Loss of Supply	98.03	23.2
Adverse Weather	177.4 7	41.9



TOTAL CHIKM = 423.05

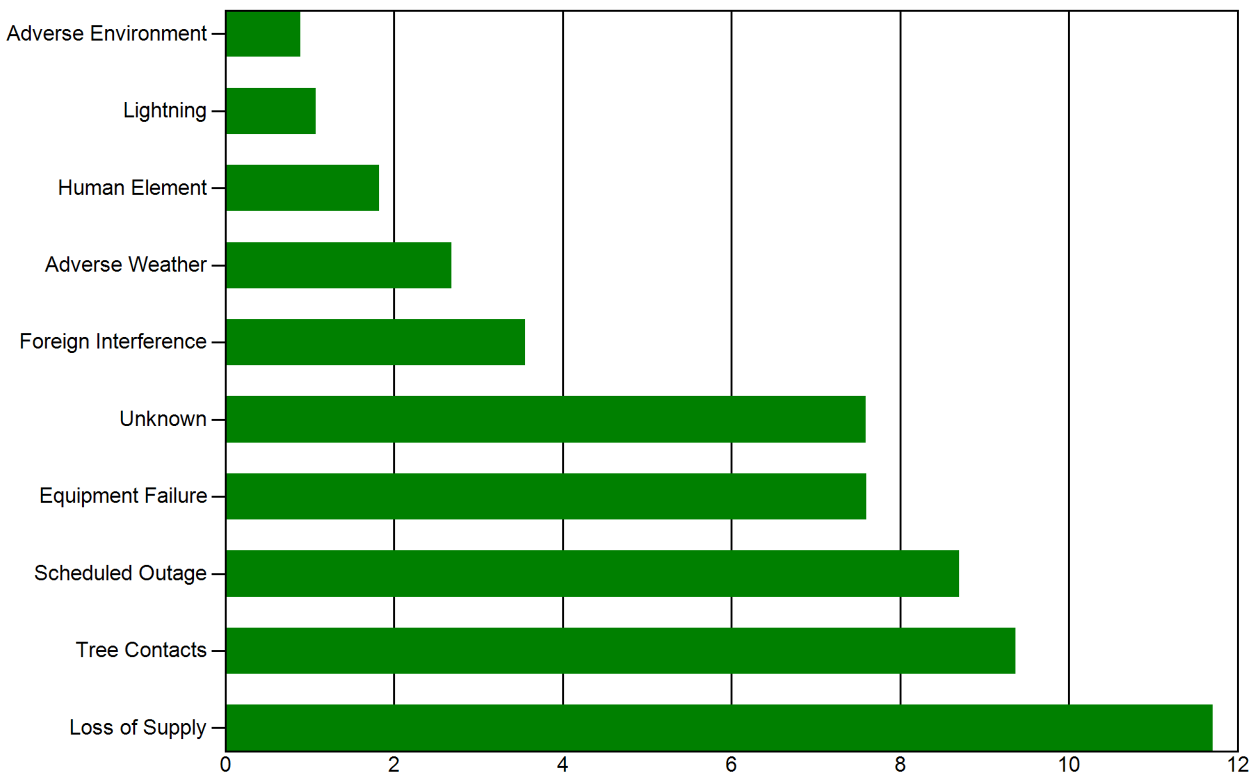
Graph 5-4a Contributions to CHIKM for 2016

CIKM

Graphs 5-5 and 5-5a indicate the contributions to CIKM for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruption per circuit km attributed to each cause.

Canadian

	CIKM	*% Customer Interruptions*
Adverse Environment	0.89	1.6
Lightning	1.07	1.9
Human Element	1.82	3.3
Adverse Weather	2.68	4.9
Foreign Interference	3.55	6.5
Unknown	7.59	13.8
Equipment Failure	7.60	13.8
Scheduled Outage	8.70	15.8
Tree Contacts	9.37	17.0
Loss of Supply	11.71	21.3

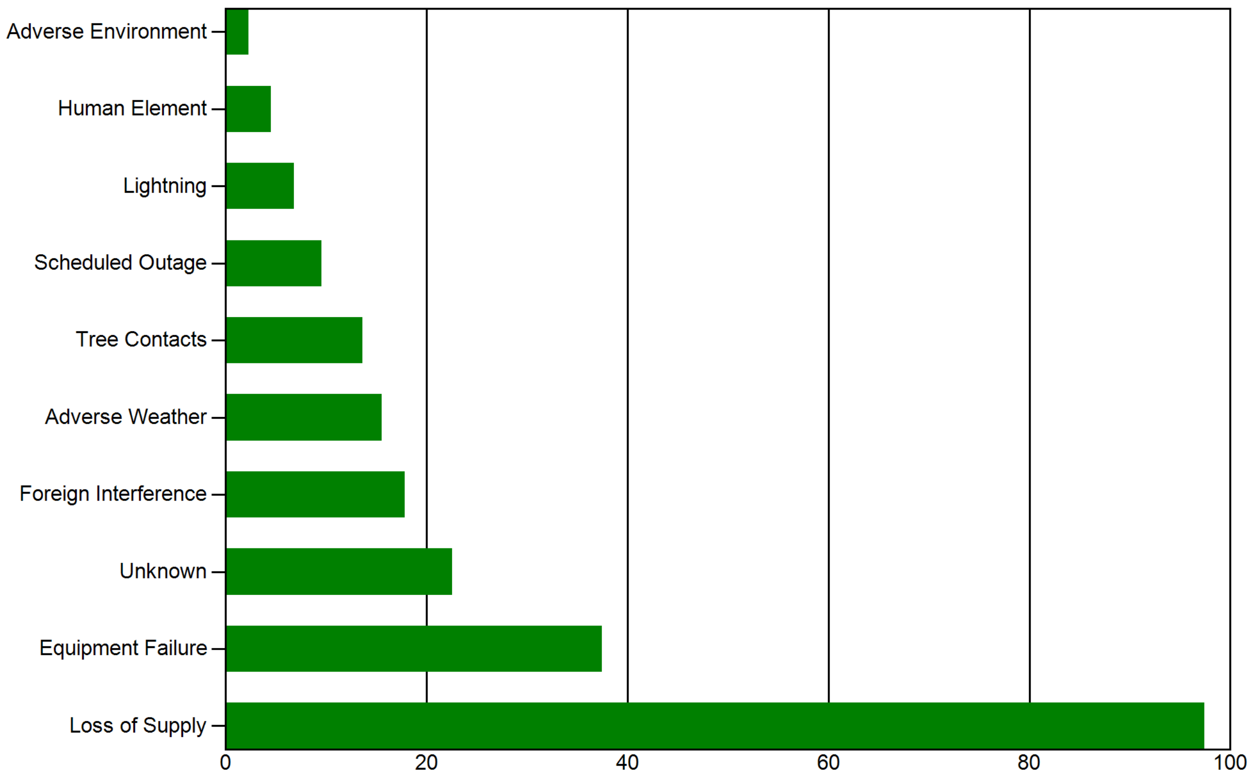


TOTAL CIKM = 54.98

Graph 5-5 Contributions to CIKM for 2016

International

	CIKM	*% Customer Interruptions*
Adverse Environment	2.29	1.0
Human Element	4.50	2.0
Lightning	6.84	3.0
Scheduled Outage	9.56	4.2
Tree Contacts	13.64	6.0
Adverse Weather	15.55	6.8
Foreign Interference	17.87	7.8
Unknown	22.55	9.9
Equipment Failure	37.47	16.5
Loss of Supply	97.43	42.8

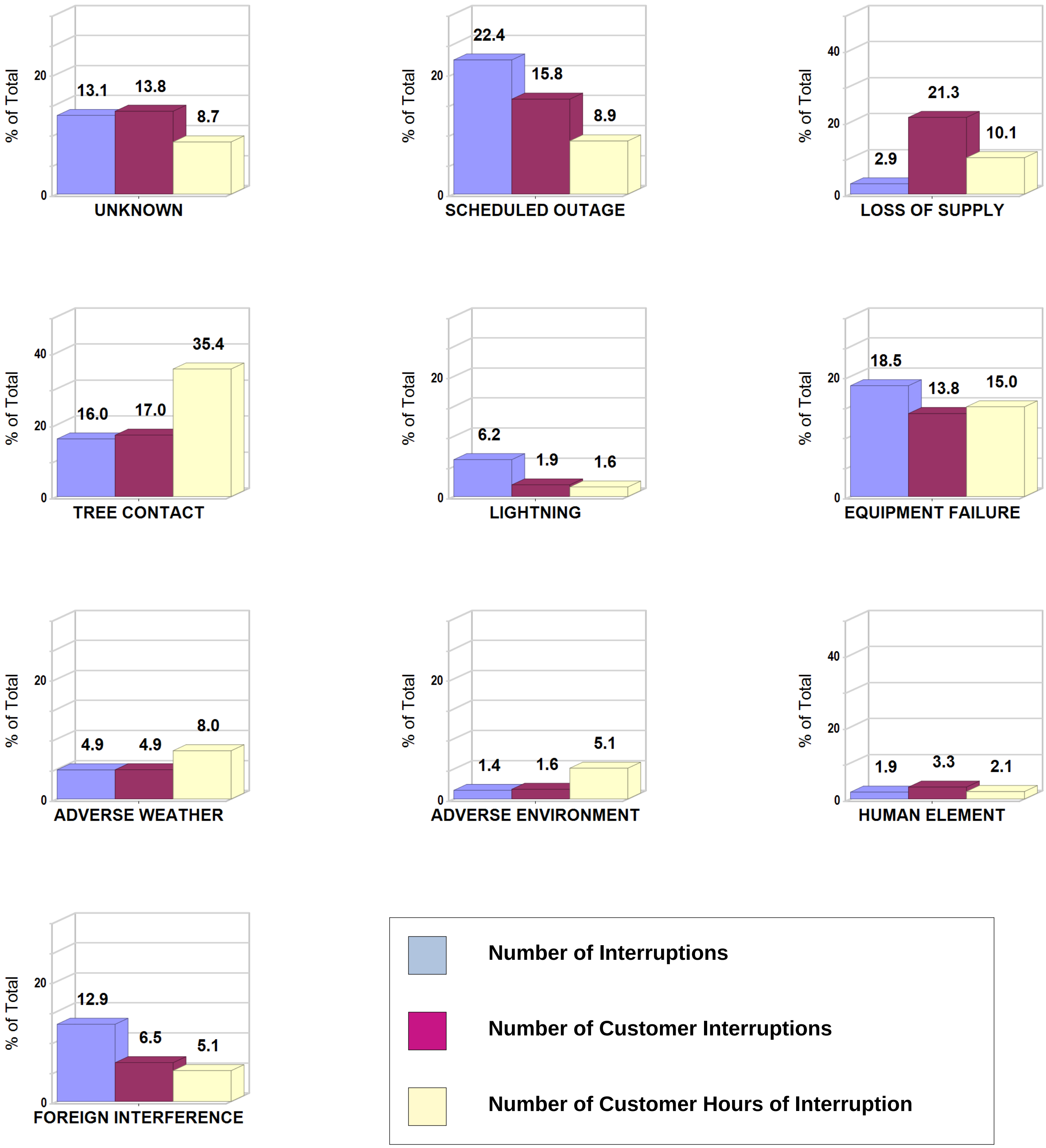


TOTAL CIKM = 227.70

Graph 5-5a Contributions to CIKM for 2016

Graph 5-6 is a comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruptions for Canadian participants.

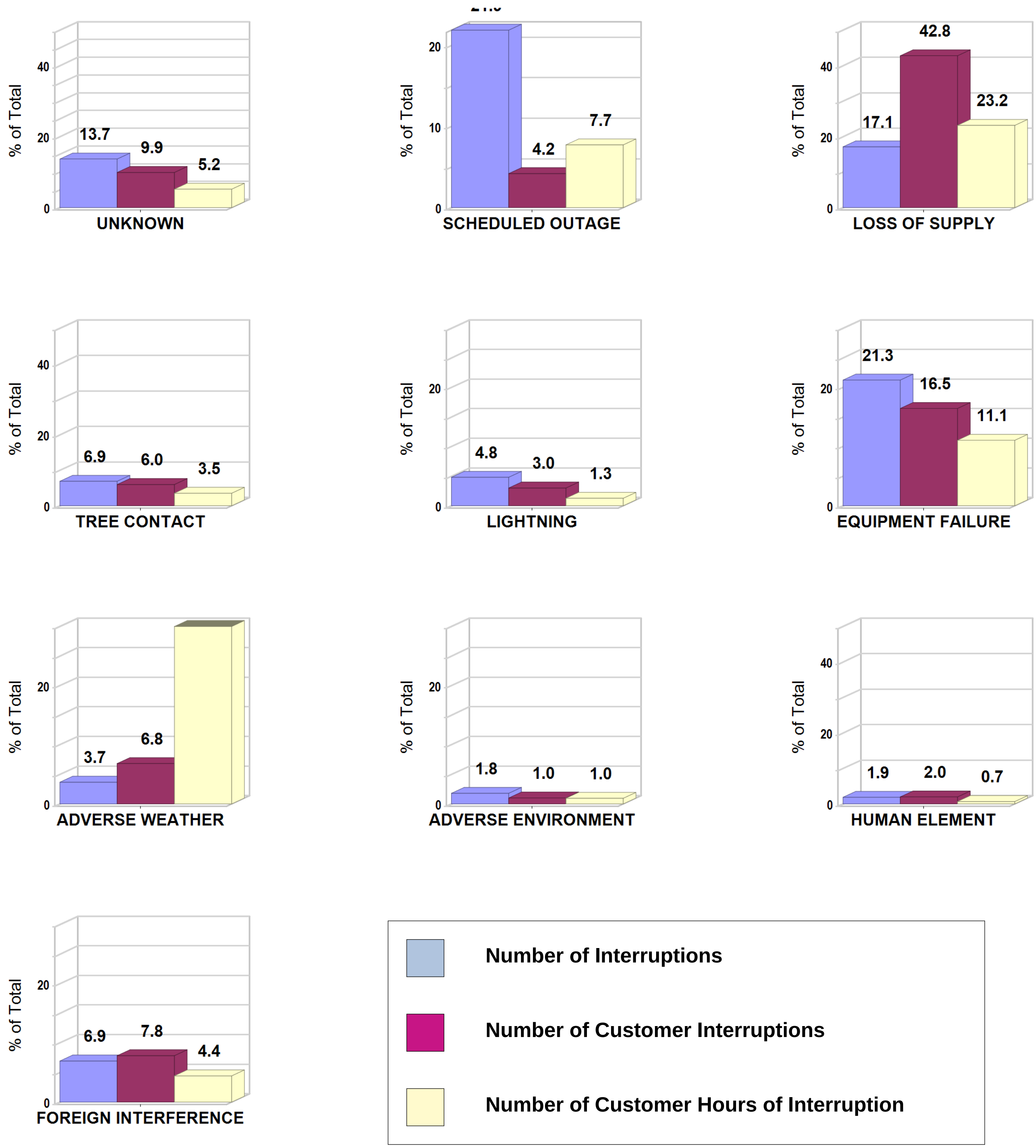
Canadian



Graph 5-6 Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2016 Canadian Data.

The following graphs show the comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruption.

International



Graph 5-6a Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2016 International Data.

The major causes of all interruptions, as compared to 2015 are:

Canadian

Unknown	**2016**	**2015**
Interruptions	13.1%	11.05%
Customer Interruptions	13.8%	14.62%
Customer Hours of Interruption	8.69%	7.65%

Scheduled Outage	**2016**	**2015**
Interruptions	22.35%	24.92%
Customer Interruptions	15.82%	9.29%
Customer Hours of Interruption	8.86%	9.82%

Loss of Supply	**2016**	**2015**
Interruptions	2.85%	2.6%
Customer Interruptions	21.3%	22.7%
Customer Hours of Interruption	10.11%	10.6%

Tree Contacts	**2016**	**2015**
Interruptions	16.0%	14.29%
Customer Interruptions	17.05%	14.95%
Customer Hours of Interruption	35.42%	28.4%

Lightning	**2016**	**2015**
Interruptions	6.15%	4.86%
Customer Interruptions	1.94%	1.73%
Customer Hours of Interruption	1.58%	1.43%

Equipment Failure	**2016**	**2015**
Interruptions	18.47%	20.45%
Customer Interruptions	13.83%	17.59%
Customer Hours of Interruption	14.95%	16.69%

Adverse Weather	**2016**	**2015**
Interruptions	4.86%	4.36%
Customer Interruptions	4.87%	5.35%
Customer Hours of Interruption	8.04%	15.5%

Adverse Environment	**2016**	**2015**
Interruptions	1.44%	1.56%
Customer Interruptions	1.62%	2.53%
Customer Hours of Interruption	5.13%	2.22%

Human Element	**2016**	**2015**
Interruptions	1.91%	2.13%
Customer Interruptions	3.3%	3.69%
Customer Hours of Interruption	2.07%	1.69%

Foreign Interference	**2016**	**2015**
Interruptions	12.86%	13.78%
Customer Interruptions	6.46%	7.56%
Customer Hours of Interruption	5.13%	5.99%

The major causes of all interruptions, as compared to 2015 are:

International Participants

Unknown	**2016**	**2015**
Interruptions	13.69%	14.13%
Customer Interruptions	9.91%	8.43%
Customer Hours of Interruption	5.2%	6.39%

Scheduled Outage	**2016**	**2015**
Interruptions	21.9%	33.68%
Customer Interruptions	4.2%	3.75%
Customer Hours of Interruption	7.74%	10.1%

Loss of Supply	**2016**	**2015**
Interruptions	17.12%	11.82%
Customer Interruptions	42.79%	35.35%
Customer Hours of Interruption	23.17%	15.31%

Tree Contacts	**2016**	**2015**
Interruptions	6.91%	5.37%
Customer Interruptions	5.99%	5.89%
Customer Hours of Interruption	3.54%	3.3%

Lightning	**2016**	**2015**
Interruptions	4.82%	1.69%
Customer Interruptions	3.01%	1.58%
Customer Hours of Interruption	1.27%	0.72%

Equipment Failure	**2016**	**2015**
Interruptions	21.25%	20.79%
Customer Interruptions	16.45%	24.32%
Customer Hours of Interruption	11.07%	23.61%

Adverse Weather	**2016**	**2015**
Interruptions	3.68%	1.82%
Customer Interruptions	6.83%	2.93%
Customer Hours of Interruption	41.95%	27.51%

Adverse Environment	**2016**	**2015**
Interruptions	1.8%	1.49%
Customer Interruptions	1.0%	1.49%
Customer Hours of Interruption	0.96%	1.33%

Human Element	**2016**	**2015**
Interruptions	1.88%	2.69%
Customer Interruptions	1.98%	5.19%
Customer Hours of Interruption	0.67%	3.71%

Foreign Interference	**2016**	**2015**
Interruptions	6.95%	6.53%
Customer Interruptions	7.85%	11.06%
Customer Hours of Interruption	4.44%	8.03%

6.0 TABULATION OF
SERVICE INTERRUPTION DATA
FOR
REGION 1 (URBAN UTILITIES)

6.0 Region 1 (Urban Utilities)

City of Lethbridge

City of Medicine Hat

City of Red Deer

Enersource Hydro Mississauga

ENMAX Power Corporation

EPCOR

Horizon Utilities

Hydro One Brampton

Hydro Ottawa

Kingston Utilities

London Hydro

Oakville Hydro Electricity Distribution

Oshawa Power and Utilities Corporation

PowerStream Inc.

Saint John Energy

Saskatoon Light & Power

St. Thomas Energy

Summerside Electric

Toronto Hydro

* B.C. Hydro - Vancouver/Burnaby District

* B.C. Hydro - Victoria District

* Hydro One - Combined Urban Areas

* Hydro-Québec - Montréal Métropolitain

* Hydro-Québec - Québec Métropolitain

* Manitoba Hydro - Winnipeg

* Maritime Electric Company - Charlottetown

* NSPI - Halifax Urban

* NSPI - Provincial Urban Areas (excl. Halifax)

TABLE 6-1 (REGION 1)
SUMMARY OF INTERRUPTION DATA
(Including Derivation of Index of Reliability)
FOR YEARS 2011 - 2016

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.
IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2016

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2011	4,098,135	18,993	5,586,221	6,692,238	35,899,658,220	0.999814
2011**	4,098,135	18,613	5,455,638	6,111,107	35,899,658,220	0.999830
2012	5,456,973	32,019	10,133,340	10,742,967	47,803,083,480	0.999775
2012**	5,456,973	31,785	9,883,968	10,276,493	47,803,083,480	0.999785
2013	5,294,438	30,971	10,861,180	34,543,885	46,379,276,880	0.999255
2013**	5,294,438	29,675	9,000,376	13,085,169	46,379,276,880	0.999718
2014	5,749,832	32,921	8,946,377	12,144,299	50,368,528,320	0.999759
2014**	5,749,832	32,897	8,943,455	12,134,863	50,368,528,320	0.999759
2015	6,043,428	30,873	8,553,674	13,461,099	52,940,429,280	0.999746
2015**	6,043,428	30,782	8,497,281	13,273,977	52,940,429,280	0.999749
2016	6,120,813	35,261	11,565,480	13,042,638	53,618,321,880	0.999757
2016**	6,120,813	35,175	11,387,970	12,339,212	53,618,321,880	0.999770

*** Excludes Significant Events*

INTERNATIONAL UTILITIES IN 2016

2011	38,810	4,072	80,502	31,024	339,975,600	0.999909
2012	45,107	2,353	78,232	28,074	395,137,320	0.999929
2013	52,628	2,916	170,511	145,780	461,021,280	0.999684
2014	69,514	2,278	114,597	53,559	608,942,640	0.999912
2015	88,117	619	89,498	52,853	771,904,920	0.999932

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

TABLE 6-2 (REGION 1)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

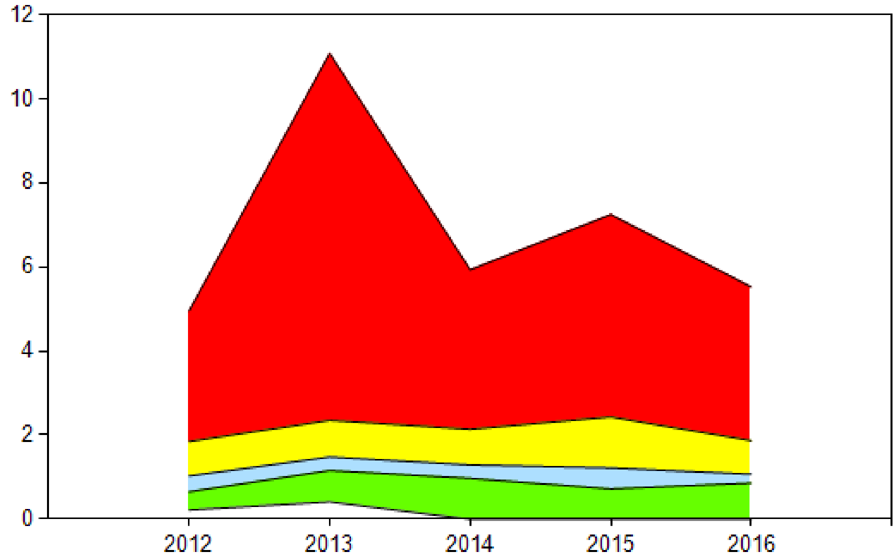
FOR YEAR 2016

Canadian

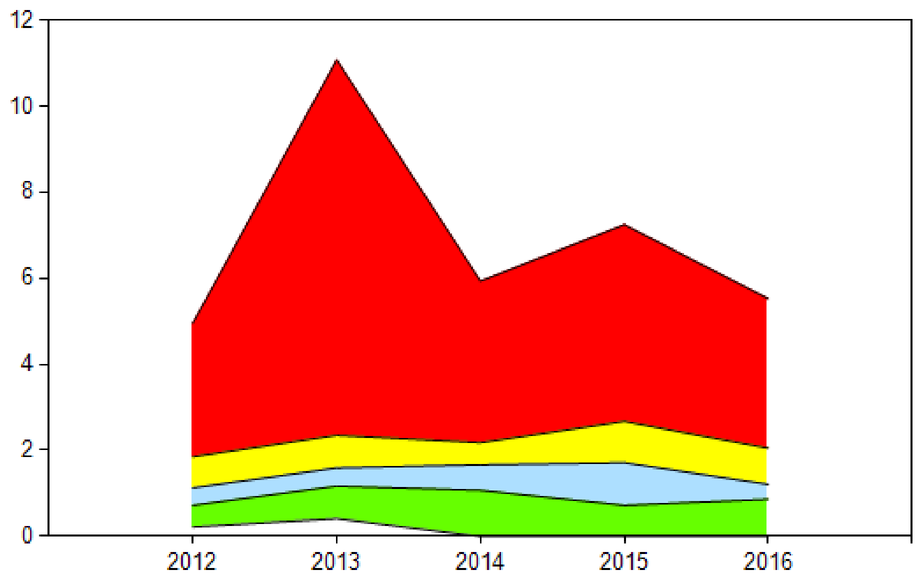
6,113,953 CUSTOMERS IN 2016
6,043,428 CUSTOMERS IN 2015

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI	CHIKM	CIKM
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)		
Unknown/Other											
2016	3,024	8.6	2,870,533	24.9	1,178,274	9.0	0.47	0.19	0.41	137.00	122.00
2015	2,350	7.6	906,751	10.6	920,543	6.8	0.15	0.15	1.02	138.00	88.00
5 YEAR AVERAGE	2,694	8.3	1,633,732	16.3	963,936	5.7	0.29	0.17	0.59	183.00	106.00
Scheduled Outage											
2016	14,540	41.3	712,532	6.2	1,660,256	12.7	0.12	0.27	2.33	137.00	122.00
2015	11,290	36.6	565,674	6.6	1,600,103	11.9	0.09	0.26	2.83	138.00	88.00
5 YEAR AVERAGE	11,793	36.4	599,973	6.0	1,569,032	9.3	0.10	0.27	2.62	183.00	106.00
Loss of Supply											
2016	1,010	2.9	2,060,749	17.8	1,652,457	12.7	0.34	0.27	0.80	137.00	122.00
2015	776	2.5	1,553,620	18.2	1,226,682	9.1	0.26	0.20	0.79	138.00	88.00
5 YEAR AVERAGE	946	2.9	1,904,619	19.0	1,897,283	11.3	0.33	0.33	1.00	183.00	106.00
Tree Contacts											
2016	2,725	7.7	1,198,611	10.4	2,791,840	21.4	0.20	0.46	2.33	137.00	122.00
2015	2,119	6.9	763,356	8.9	1,914,013	14.2	0.13	0.32	2.51	138.00	88.00
5 YEAR AVERAGE	2,551	7.9	912,378	9.1	2,513,492	15.0	0.16	0.44	2.75	183.00	106.00
Lightning											
2016	431	1.2	201,346	1.7	276,504	2.1	0.03	0.05	1.37	137.00	122.00
2015	396	1.3	199,530	2.3	177,100	1.3	0.03	0.03	0.89	138.00	88.00
5 YEAR AVERAGE	452	1.4	270,850	2.7	253,334	1.5	0.05	0.04	0.94	183.00	106.00
Defective Equipment											
2016	7,316	20.8	2,149,569	18.6	2,716,383	20.9	0.35	0.44	1.26	137.00	122.00
2015	7,478	24.2	2,062,032	24.1	2,679,702	19.9	0.34	0.44	1.30	138.00	88.00
5 YEAR AVERAGE	7,352	22.7	2,086,574	20.8	2,679,201	16.0	0.36	0.47	1.28	183.00	106.00
Adverse Weather											
2016	742	2.1	567,279	4.9	969,112	7.4	0.09	0.16	1.71	137.00	122.00
2015	1,016	3.3	596,410	7.0	2,784,511	20.7	0.10	0.46	4.67	138.00	88.00
5 YEAR AVERAGE	1,230	3.8	939,568	9.4	4,681,026	27.9	0.16	0.82	4.98	183.00	106.00
Adverse Environment											
2016	714	2.0	395,741	3.4	483,489	3.7	0.06	0.08	1.22	137.00	122.00
2015	766	2.5	559,354	6.5	876,907	6.5	0.09	0.15	1.57	138.00	88.00
5 YEAR AVERAGE	970	3.0	455,257	4.5	1,144,963	6.8	0.08	0.20	2.51	183.00	106.00
Human Element											
2016	674	1.9	531,593	4.6	452,978	3.5	0.09	0.07	0.85	137.00	122.00
2015	685	2.2	552,431	6.5	511,807	3.8	0.09	0.08	0.93	138.00	88.00
5 YEAR AVERAGE	531	1.6	386,428	3.9	289,538	1.7	0.07	0.05	0.75	183.00	106.00
Foreign Interference											
2016	4,030	11.4	863,059	7.5	846,826	6.5	0.14	0.14	0.98	137.00	122.00
2015	3,997	12.9	794,516	9.3	769,733	5.7	0.13	0.13	0.97	138.00	88.00
5 YEAR AVERAGE	3,879	12.0	819,739	8.2	792,269	4.7	0.14	0.14	0.97	183.00	106.00
Total											
2016	35,206	100.0	11,551,012	100.0	13,028,119	100.0	1.89	2.13	1.13	137.00	122.00
2015	30,873	100.0	8,553,674	100.0	13,461,099	100.0	1.42	2.23	1.57	138.00	88.00
5 YEAR AVERAGE	32,398	100.0	10,009,117	100.0	16,784,074	100.0	1.75	2.93	1.68	183.00	106.00

Note: Quartiles include Canadian and International Utilities

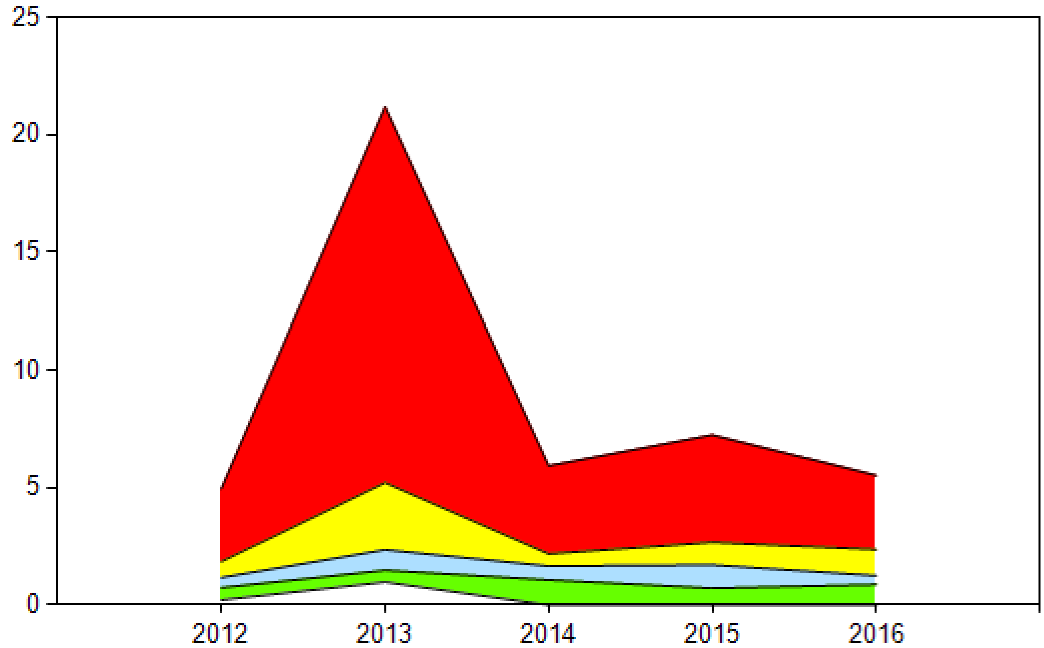


Graph 6-1: Region 1 SAIDI, Excluding MPEs

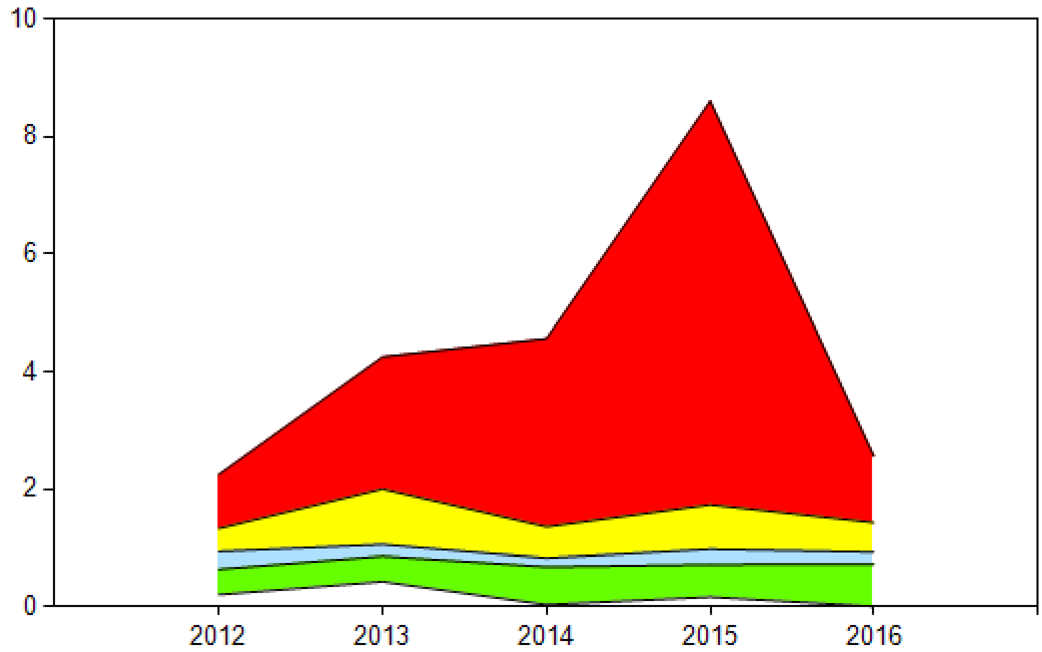


Graph 6-2: Region 1 SAIDI, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities

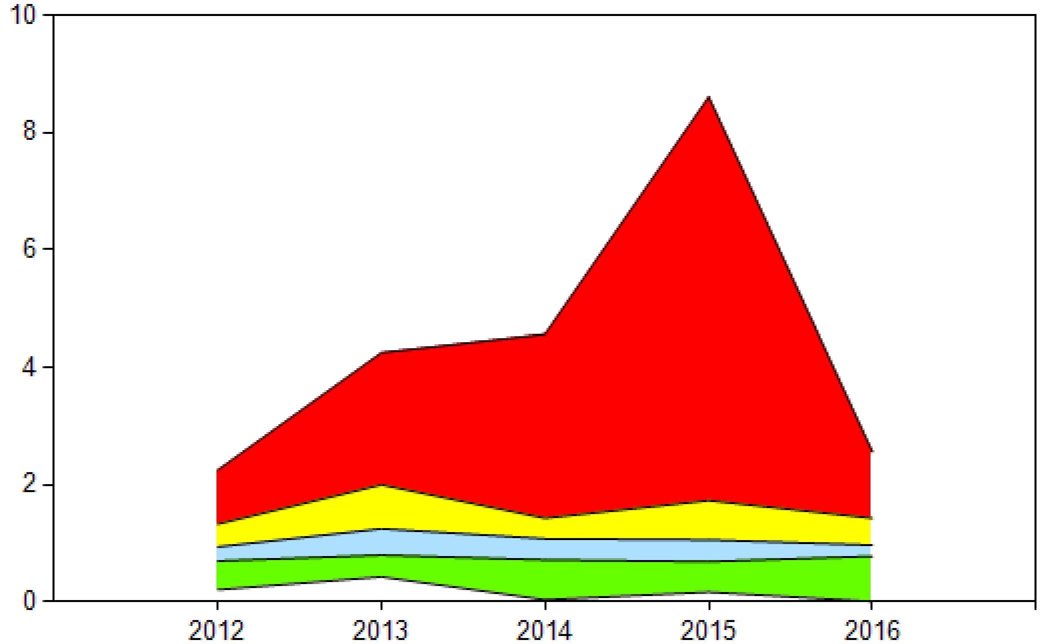


Graph 6-3: Region 1 SAIDI, Including All Events

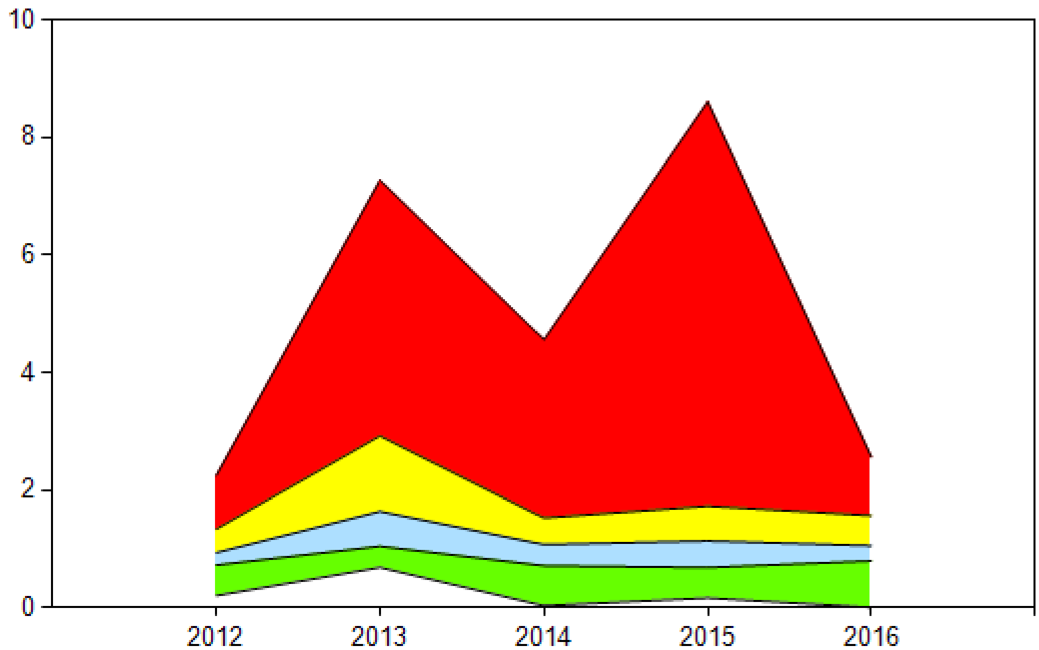


Graph 6-4: Region 1 CAIDI, Excluding MPEs

Note: Quartiles include Canadian and International Utilities

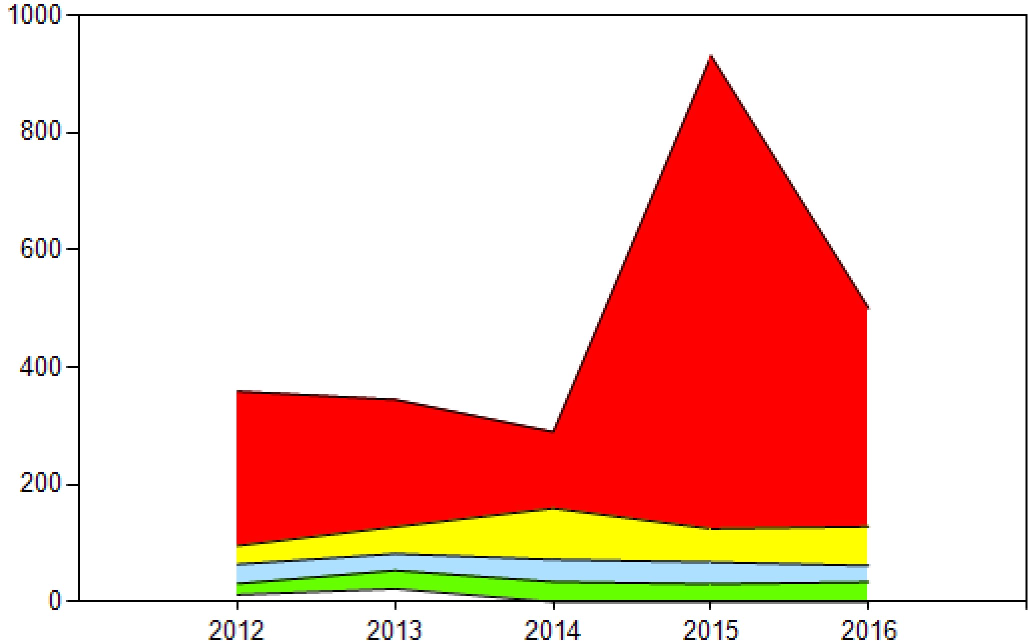


Graph 6-5: Region 1 CAIDI, Excluding Significant Events

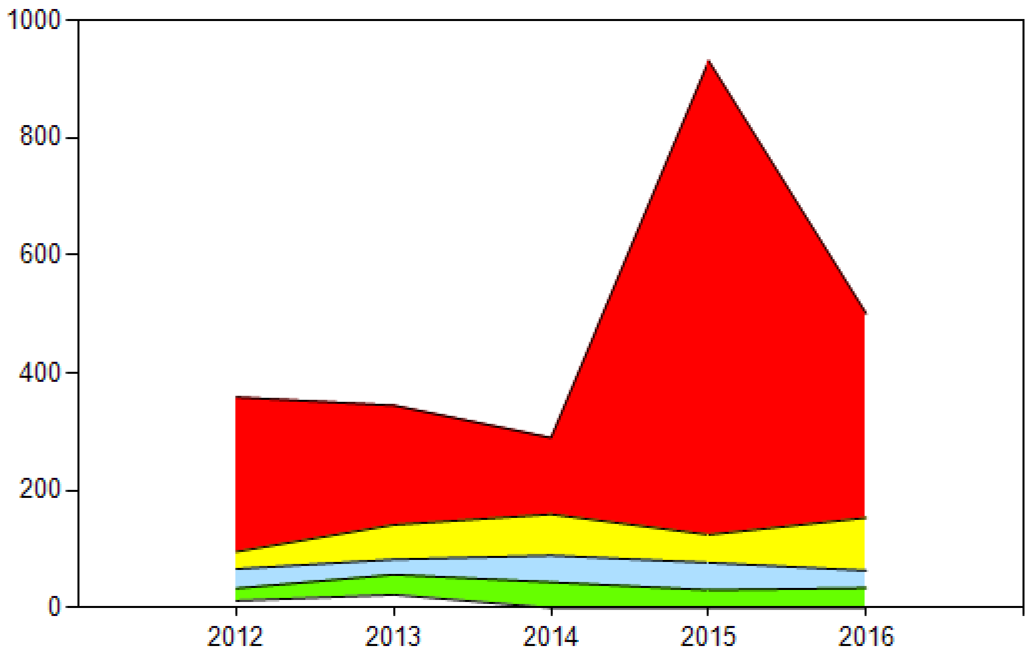


Graph 6-6: Region 1 CAIDI, Including All Events

Note: Quartiles include Canadian and International Utilities

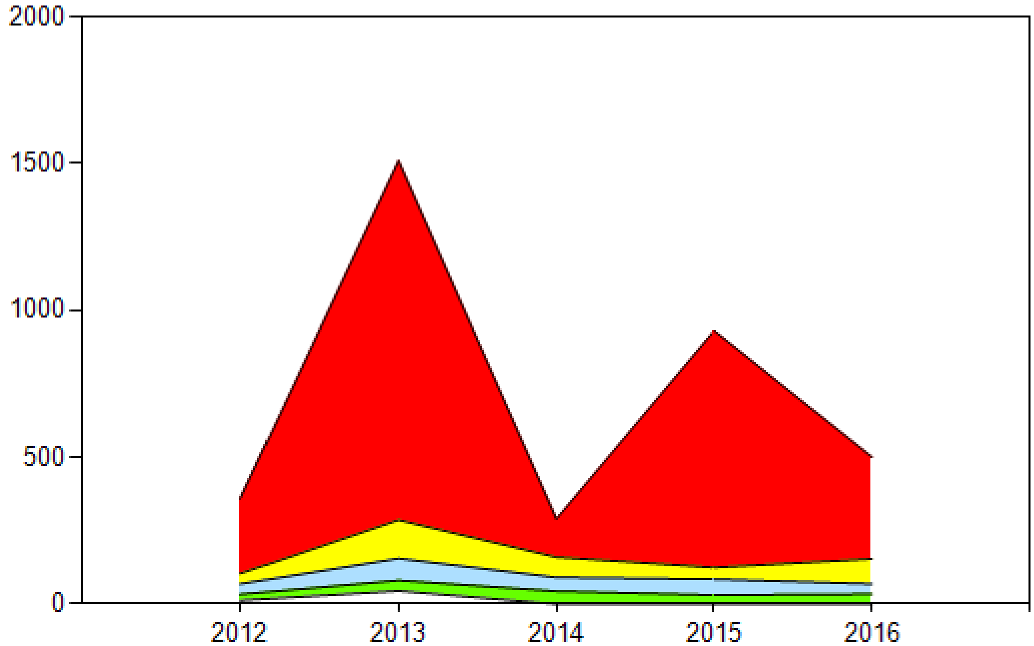


Graph 6-7: Region 1 CHIKM, Excluding MPEs

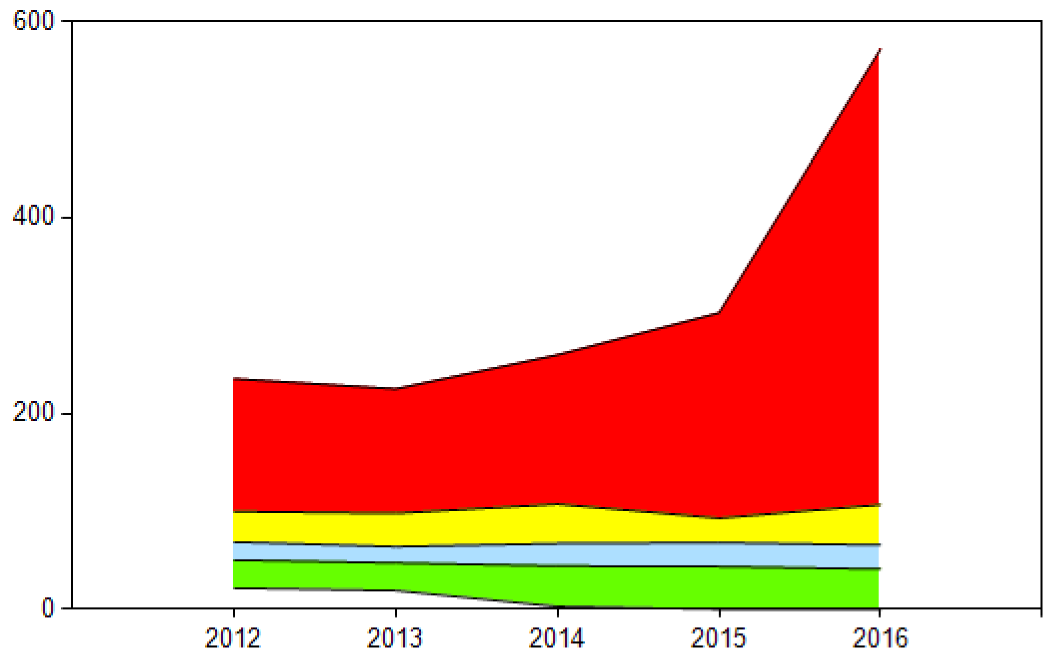


Graph 6-8: Region 1 CHIKM, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities

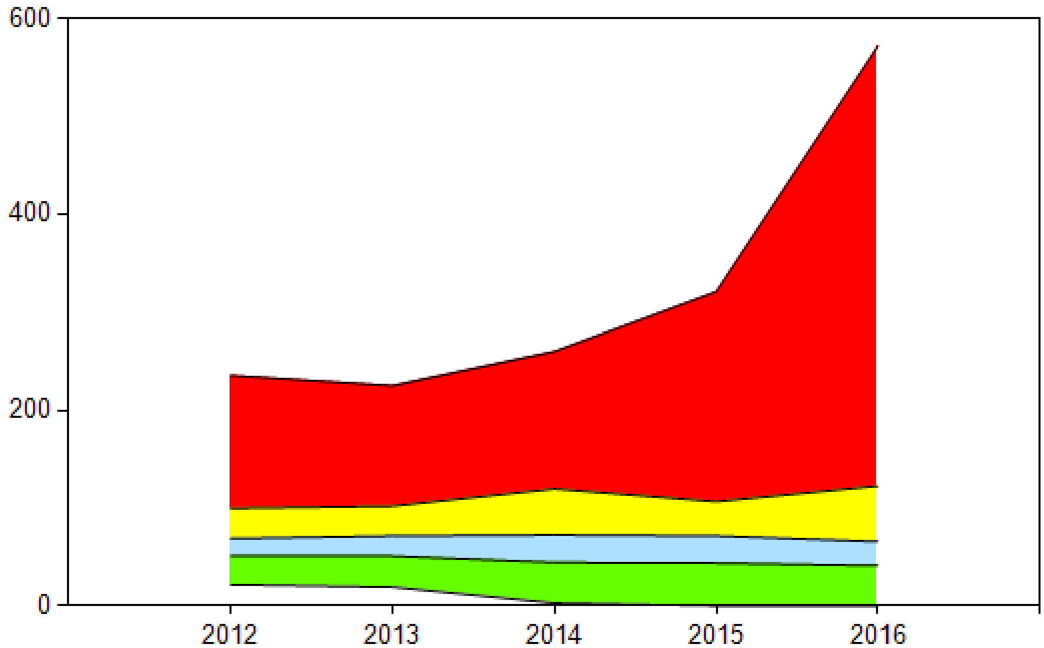


Graph 6-9: Region 1 CHIKM, Including All Events

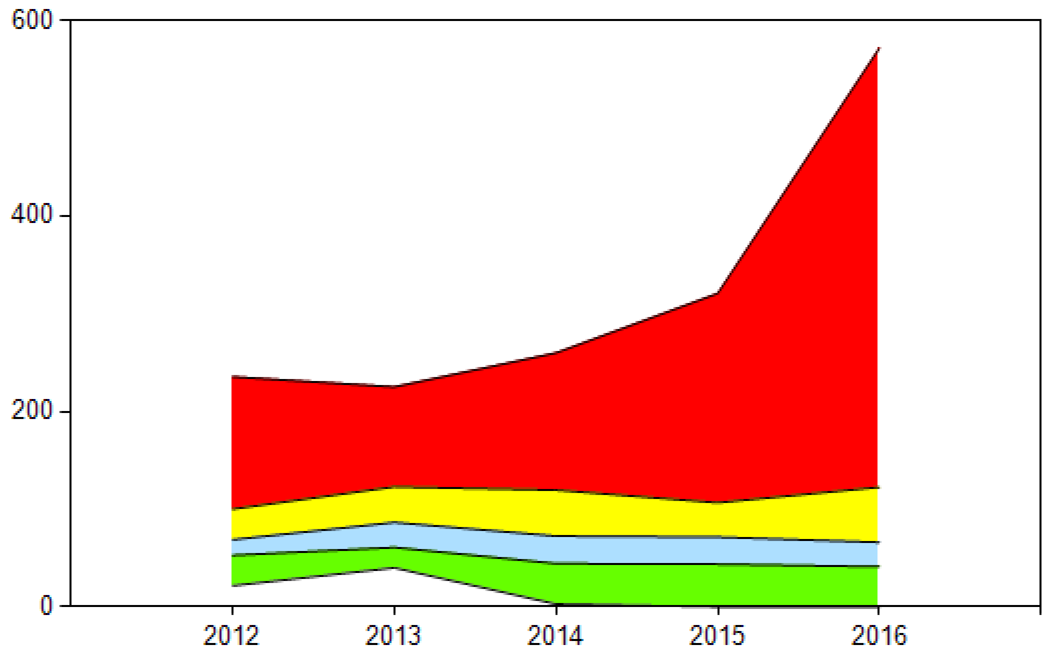


Graph 6-10: Region 1 CIKM, Excluding MPEs

Note: Quartiles include Canadian and International Utilities

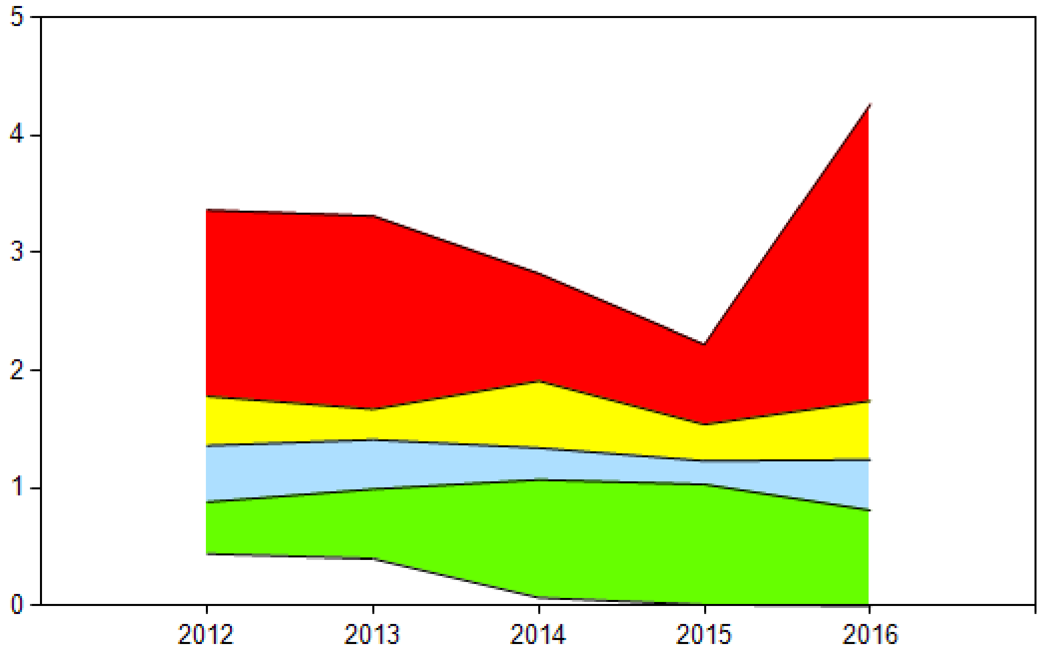


Graph 6-11: Region 1 CIKM, Excluding Significant Events

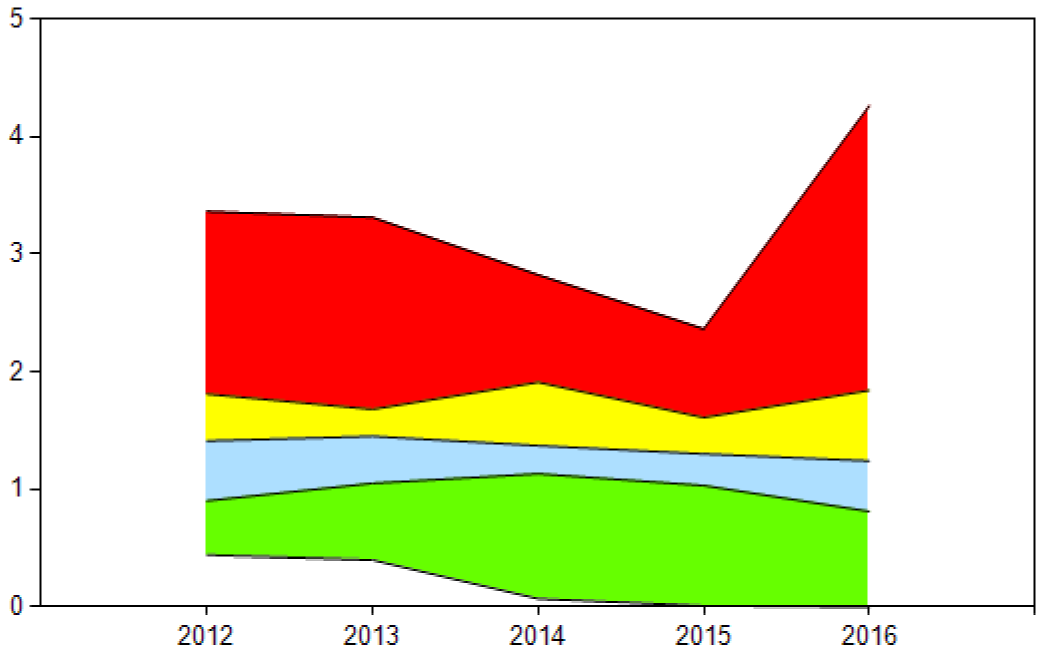


Graph 6-12: Region 1 CIKM, Including All Events

Note: Quartiles include Canadian and International Utilities

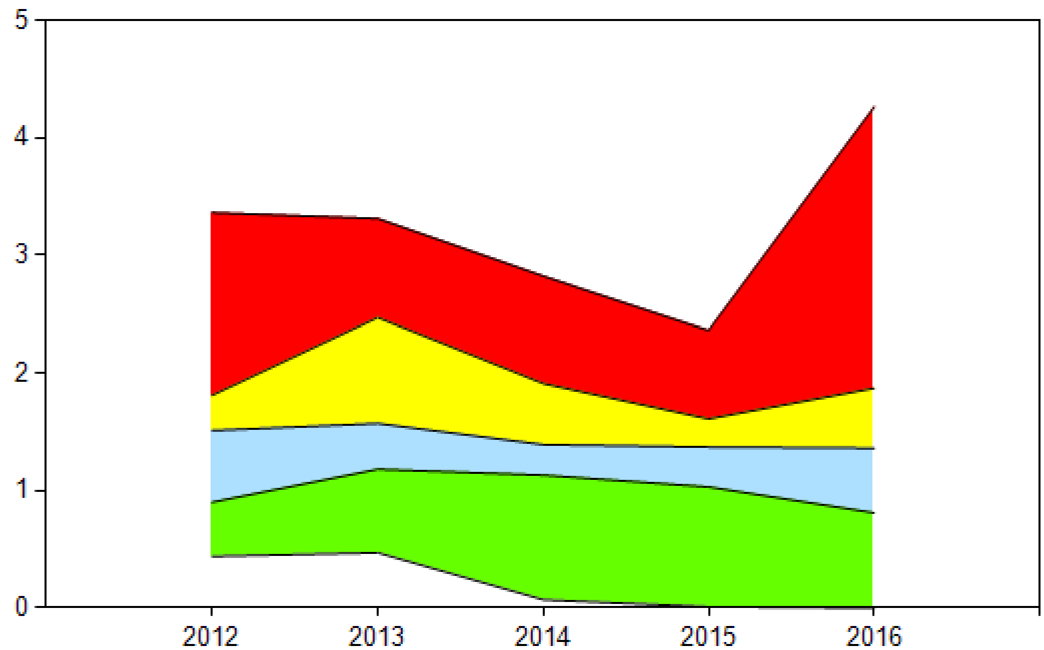


Graph 6-13: Region 1 SAIFI, Excluding MPEs



Graph 6-14: Region 1 SAIFI, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities



Graph 6-15: Region 1 SAIFI, Including All Events

7.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 2 (URBAN/RURAL UTILITIES)

7.0 Region 2 (Urban / Rural Utilities)

ATCO Electric

B.C. Hydro

Barbados Light & Power Company

Caribbean Utilities

Dominica Electricity Services Ltd.

FortisAlberta

FortisBC

Grand Bahama Power Company

Hydro One

Hydro-Québec

Manitoba Hydro

Maritime Electric Company

New Brunswick Power

Newfoundland & Labrador Hydro

Newfoundland Power

Newmarket-Tay Power Distribution Ltd.

Northland Utilities (NWT)

Northland Utilities (Yellowknife)

Northwest Territories Power Corporation

Nova Scotia Power Inc.

Qulliq Energy Corporation

SaskPower

St. Lucia Electricity Services

Veridian Connections

Waterloo North Hydro Inc.

Yukon Electrical Co. Ltd.

Yukon Energy

TABLE 7-1 (REGION 2)
SUMMARY OF INTERRUPTION DATA
(Including Derivation of Index of Reliability)
FOR YEARS 2011 - 2016

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.
IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2016

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2011	10,326,243	236,958	30,682,291	77,424,503	90,457,888,680	0.999144
2011**	10,326,243	227,883	29,414,607	64,028,521	90,457,888,680	0.999292
2012	10,520,087	228,415	29,813,908	59,041,000	92,155,962,120	0.999359
2012**	10,520,087	225,728	29,305,502	56,421,959	92,155,962,120	0.999388
2013	10,660,339	248,987	31,338,135	104,740,011	93,384,569,640	0.998878
2013**	10,660,339	234,085	29,510,555	77,429,859	93,384,569,640	0.999171
2014	10,800,893	249,987	28,793,848	84,390,893	94,615,822,680	0.999108
2014**	10,800,893	240,892	27,944,301	65,970,910	94,615,822,680	0.999303
2015	10,930,018	240,716	28,646,113	68,474,108	95,746,957,680	0.999285
2015**	10,930,018	234,785	27,106,333	51,448,001	95,746,957,680	0.999463
2016	11,037,599	278,098	40,901,021	78,101,848	96,689,367,240	0.999192
2016**	11,037,599	266,913	36,530,085	60,555,694	96,689,367,240	0.999374

*** Excludes Significant Events*

INTERNATIONAL UTILITIES IN 2016

2011	122,049	2,826	839,078	706,115	1,069,149,240	0.999340
2012	61,192	571	640,714	723,712	536,041,920	0.998650
2013	532,925	13,818	2,913,019	3,597,344	4,668,423,000	0.999229
2014	717,629	17,491	6,482,752	5,602,845	6,286,430,040	0.999109
2015	273,620	1,801	2,089,429	2,832,030	2,396,911,200	0.998818
2016	276,529	2,447	2,273,771	4,224,430	2,422,394,040	0.998256
2016**	276,529	2,418	2,154,361	2,481,424	2,422,394,040	0.998976

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

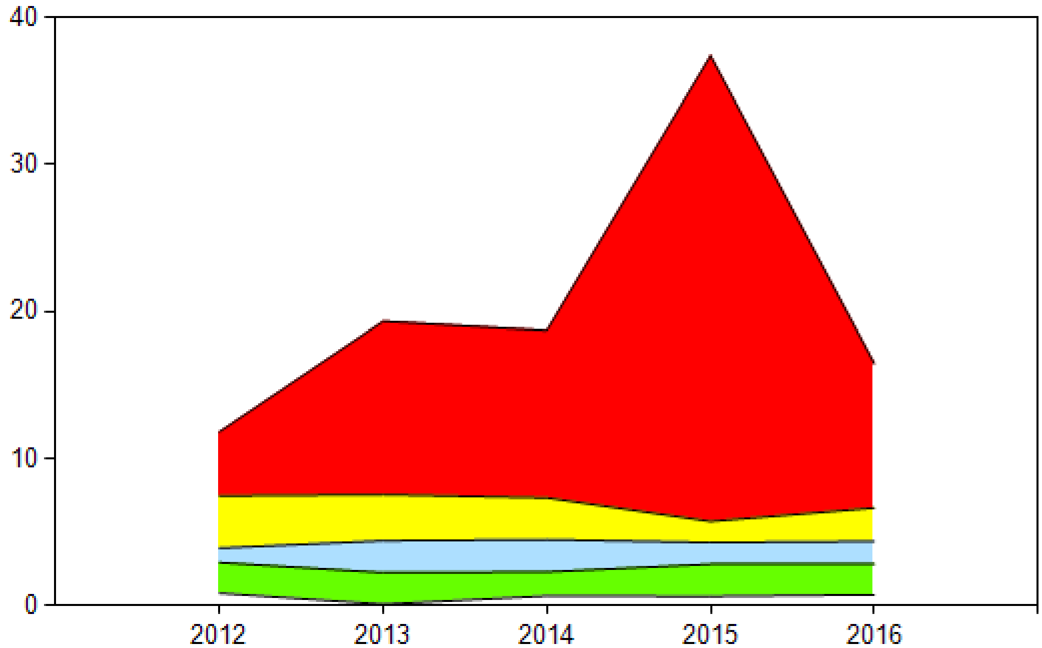
TABLE 7-2 (REGION 2)
SYSTEM CAUSES OF SERVICE INTERRUPTIONS
FOR YEAR 2016

Canadian

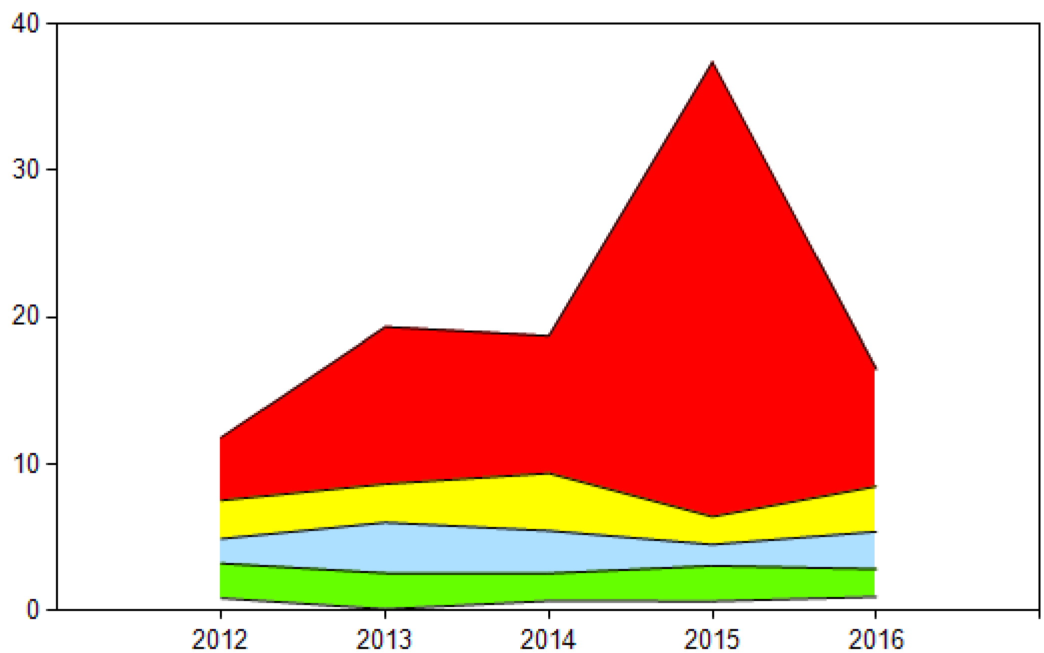
11,037,599 CUSTOMERS IN 2016
10,930,018 CUSTOMERS IN 2015

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI	CHIKM	CIKM
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)		
Unknown/Other											
2016	37,753	13.6	5,699,218	13.9	7,011,326	9.0	0.52	0.64	1.23	9.00	8.00
2015	27,440	11.4	4,458,964	15.6	5,471,059	8.0	0.41	0.50	1.23	7.00	6.00
5 YEAR AVERAGE	30,802	12.4	4,618,402	14.5	7,241,071	9.2	0.43	0.67	1.57	8.00	5.00
Scheduled Outage											
2016	57,814	20.8	6,876,095	16.8	6,843,620	8.8	0.62	0.62	1.00	9.00	9.00
2015	57,749	24.0	2,927,644	10.2	6,710,068	9.8	0.27	0.61	2.29	9.00	4.00
5 YEAR AVERAGE	51,127	20.5	3,442,529	10.8	6,635,464	8.4	0.32	0.61	1.93	8.00	4.00
Loss of Supply											
2016	8,126	2.9	9,125,731	22.3	7,793,843	10.0	0.83	0.71	0.85	10.00	12.00
2015	6,332	2.6	6,792,015	23.7	7,322,239	10.7	0.62	0.67	1.08	10.00	9.00
5 YEAR AVERAGE	6,794	2.7	8,004,255	25.1	7,957,037	10.1	0.74	0.74	0.99	9.00	9.00
Tree Contacts											
2016	46,434	16.7	7,345,355	18.0	28,722,698	36.8	0.67	2.60	3.91	38.00	10.00
2015	35,811	14.9	4,762,459	16.6	20,356,619	29.7	0.44	1.86	4.27	27.00	6.00
5 YEAR AVERAGE	43,879	17.6	5,705,953	17.9	28,917,870	36.6	0.53	2.68	5.07	33.00	7.00
Lightning											
2016	17,754	6.4	718,873	1.8	1,144,266	1.5	0.07	0.10	1.59	2.00	1.00
2015	12,149	5.0	429,084	1.5	928,044	1.4	0.04	0.08	2.16	1.00	1.00
5 YEAR AVERAGE	13,876	5.6	645,436	2.0	1,303,645	1.7	0.06	0.12	2.02	2.00	1.00
Defective Equipment											
2016	51,112	18.4	5,032,039	12.3	10,965,985	14.0	0.46	0.99	2.18	15.00	7.00
2015	48,713	20.2	4,576,404	16.0	10,911,565	15.9	0.42	1.00	2.38	15.00	6.00
5 YEAR AVERAGE	47,929	19.2	4,525,740	14.2	11,255,815	14.3	0.42	1.04	2.49	13.00	5.00
Adverse Weather											
2016	13,840	5.0	1,845,054	4.5	6,086,224	7.8	0.17	0.55	3.30	8.00	2.00
2015	10,543	4.4	1,361,807	4.8	10,770,078	15.7	0.12	0.99	7.91	14.00	0.00
5 YEAR AVERAGE	12,201	4.9	1,581,905	5.0	7,244,340	9.2	0.15	0.67	4.58	8.00	2.00
Adverse Environment											
2016	4,145	1.5	678,809	1.7	4,166,482	5.3	0.06	0.38	6.14	6.00	1.00
2015	3,676	1.5	443,874	1.5	967,647	1.4	0.04	0.09	2.18	1.00	1.00
5 YEAR AVERAGE	4,592	1.8	614,913	1.9	1,870,098	2.4	0.06	0.17	3.04	2.00	1.00
Human Element											
2016	5,414	1.9	1,293,573	3.2	1,615,658	2.1	0.12	0.15	1.25	2.00	2.00
2015	5,190	2.2	967,982	3.4	1,113,550	1.6	0.09	0.10	1.15	1.00	1.00
5 YEAR AVERAGE	4,100	1.6	775,721	2.4	934,372	1.2	0.07	0.09	1.20	1.00	1.00
Foreign Interference											
2016	35,706	12.8	2,286,274	5.6	3,751,746	4.8	0.21	0.34	1.64	5.00	3.00
2015	33,113	13.8	1,925,880	6.7	3,923,241	5.7	0.18	0.36	2.04	5.00	3.00
5 YEAR AVERAGE	33,941	13.6	1,983,750	6.2	5,589,862	7.1	0.18	0.52	2.82	6.00	2.00
Total											
2016	278,098	100.0	40,901,021	100.0	78,101,848	100.0	3.71	7.08	1.91	104.00	54.00
2015	240,716	100.0	28,646,113	100.0	68,474,108	100.0	2.62	6.26	2.39	91.00	38.00
5 YEAR AVERAGE	249,241	100.0	31,898,605	100.0	78,949,572	100.0	2.96	7.32	2.48	90.00	37.00

Note: Quartiles include Canadian and International Utilities

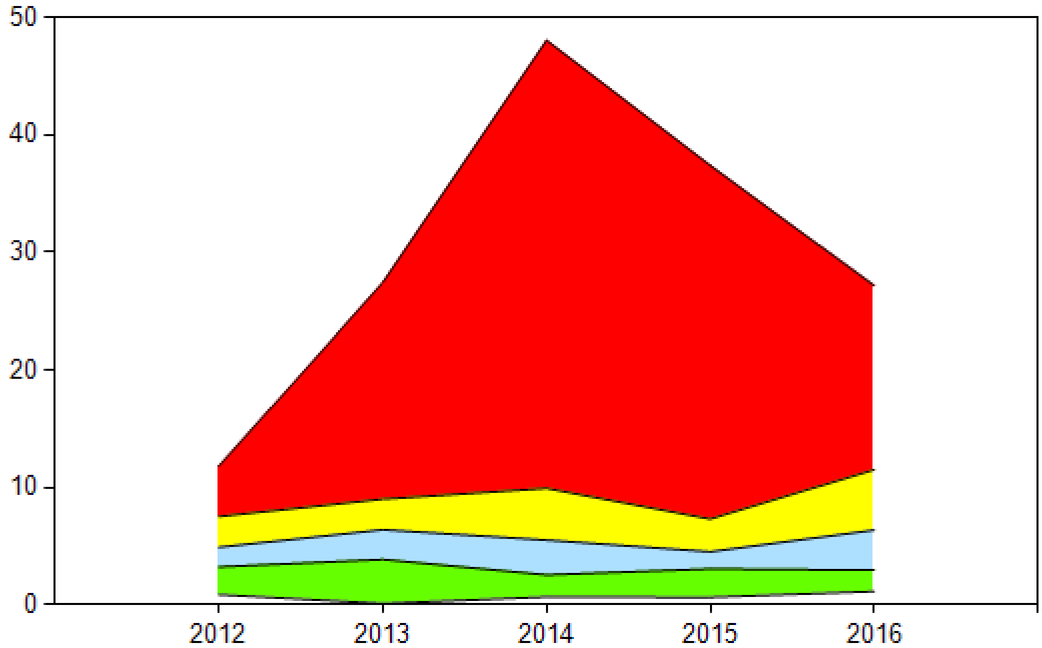


Graph 7-1: Region 2 SAIDI, Excluding MPEs

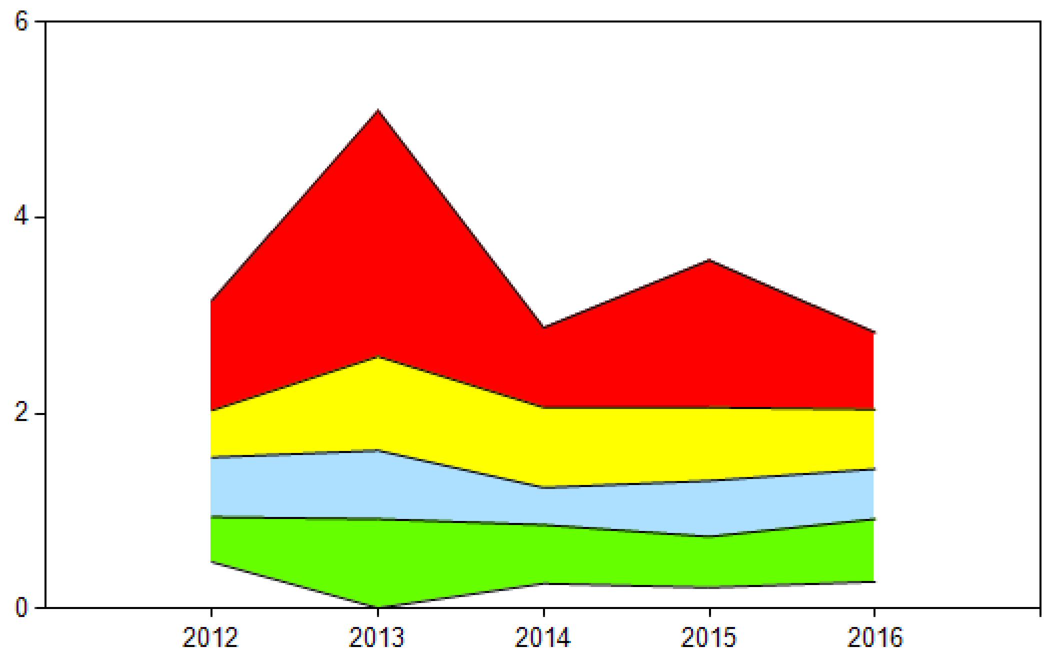


Graph 7-2: Region 2 SAIDI, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities

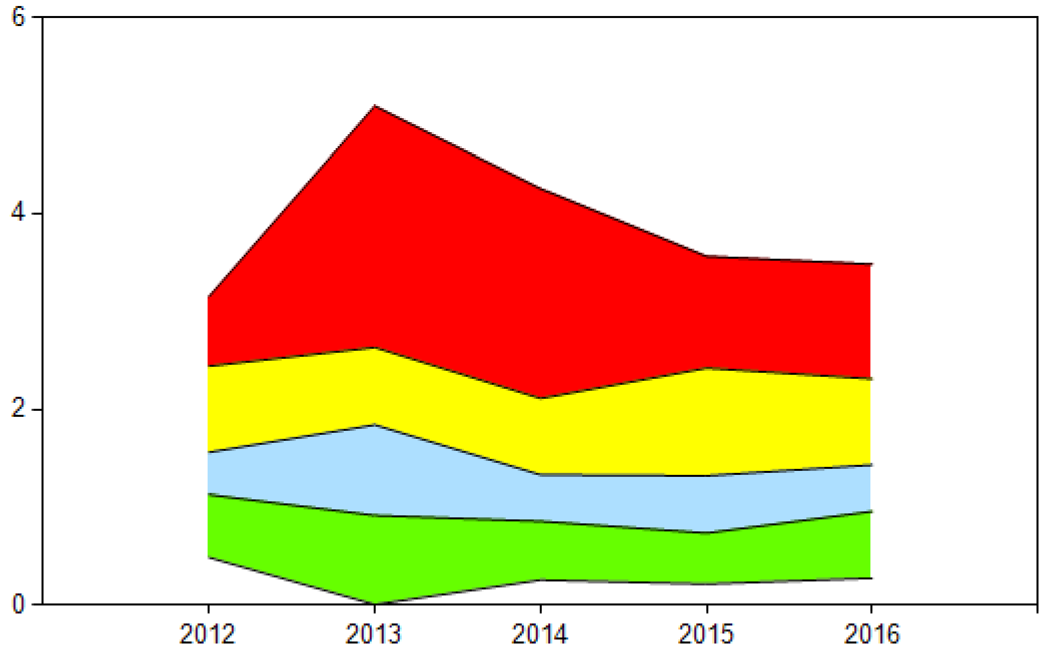


Graph 7-3: Region 2 SAIDI, Including All Events

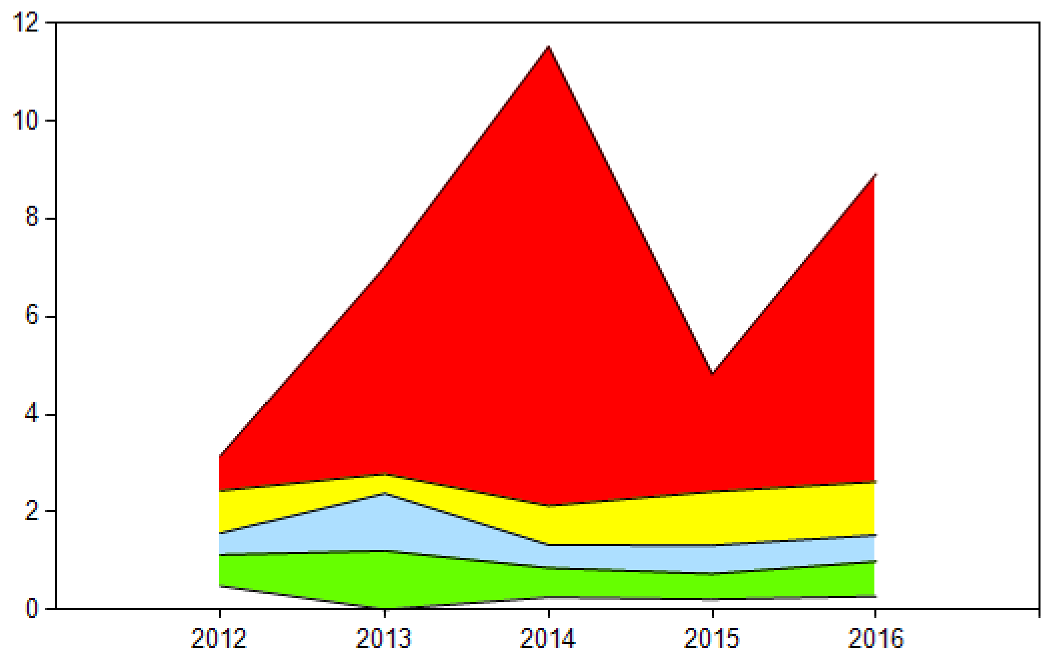


Graph 7-4: Region 2 CAIDI, Excluding MPEs

Note: Quartiles include Canadian and International Utilities

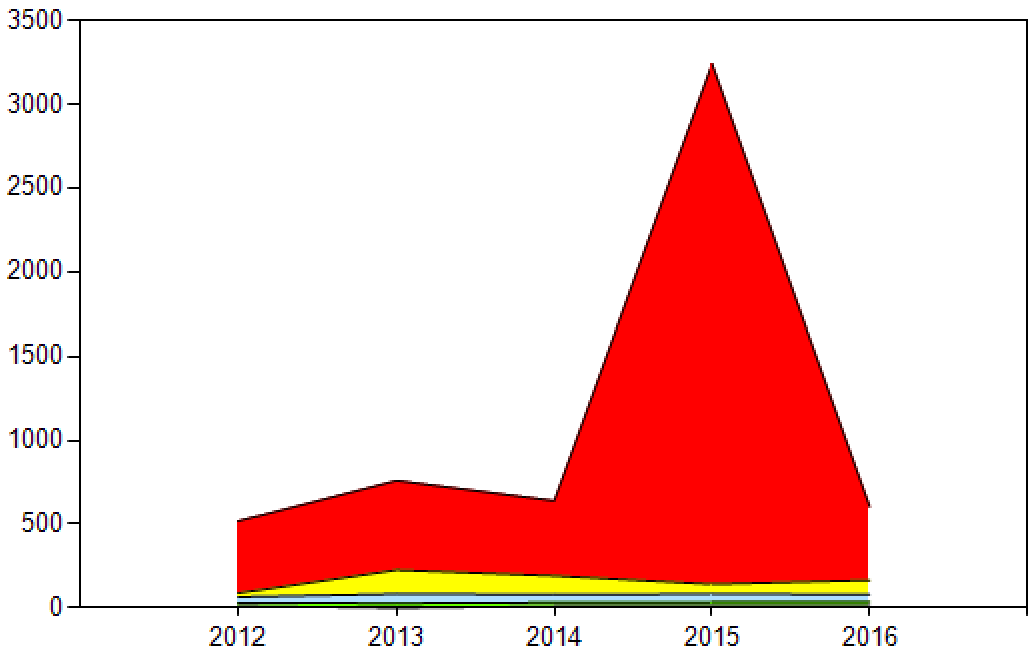


Graph 7-5: Region 2 CAIDI, Excluding Significant Events

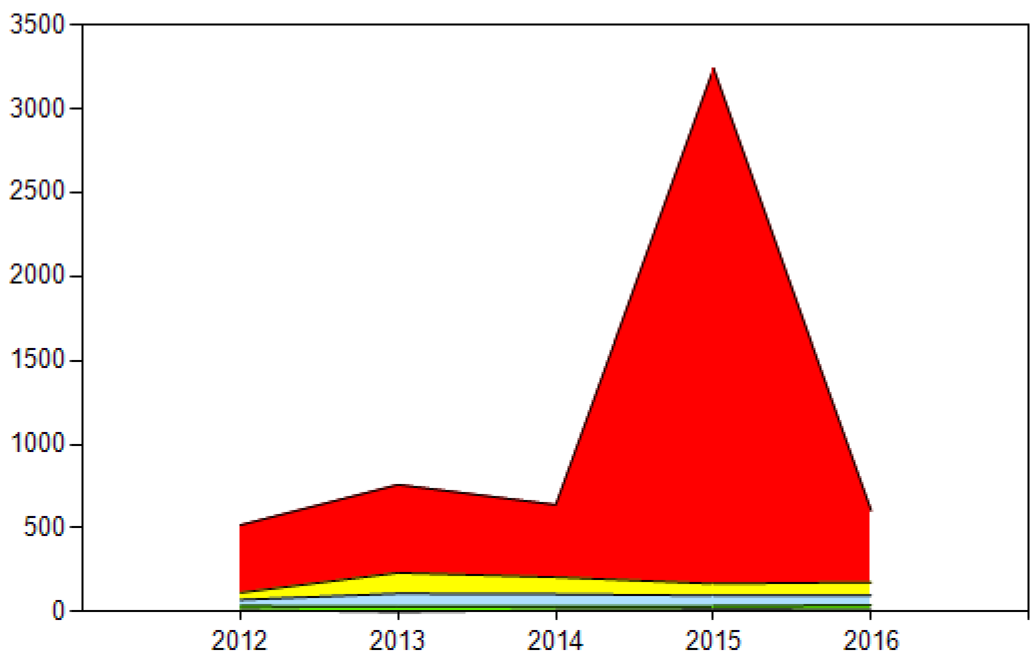


Graph 7-6: Region 2 CAIDI, Including All Events

Note: Quartiles include Canadian and International Utilities

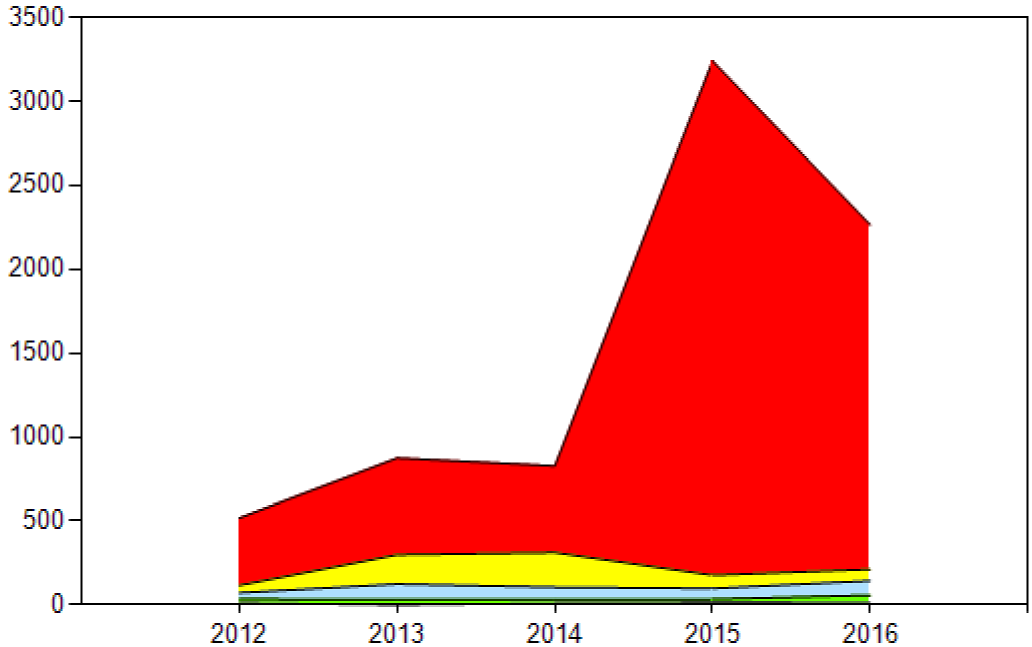


Graph 7-7: Region 2 CHIKM, Excluding MPEs

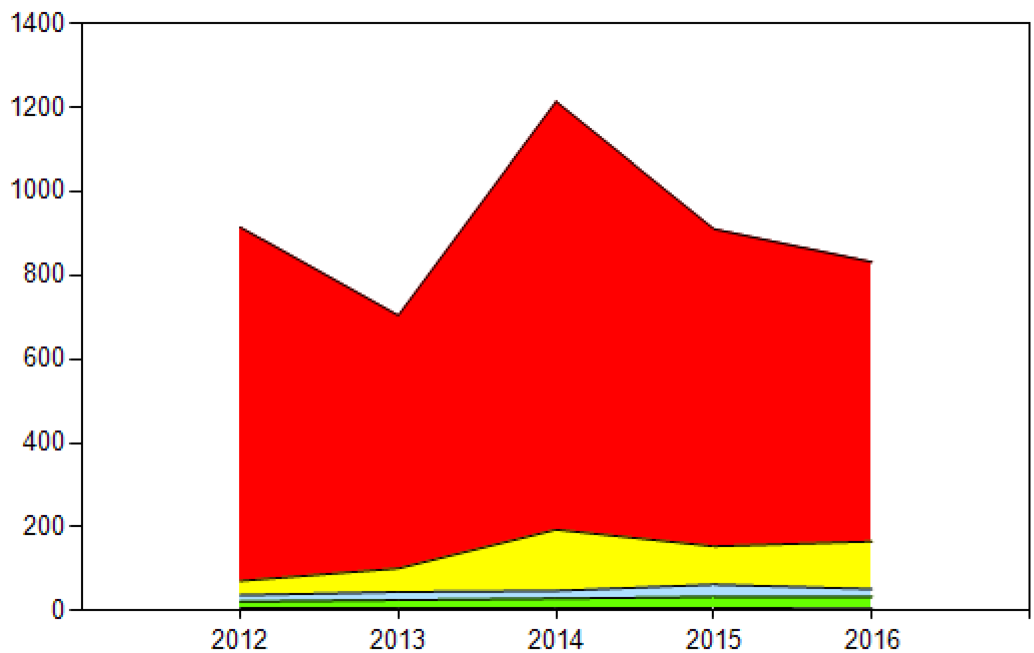


Graph 7-8: Region 2 CHIKM, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities

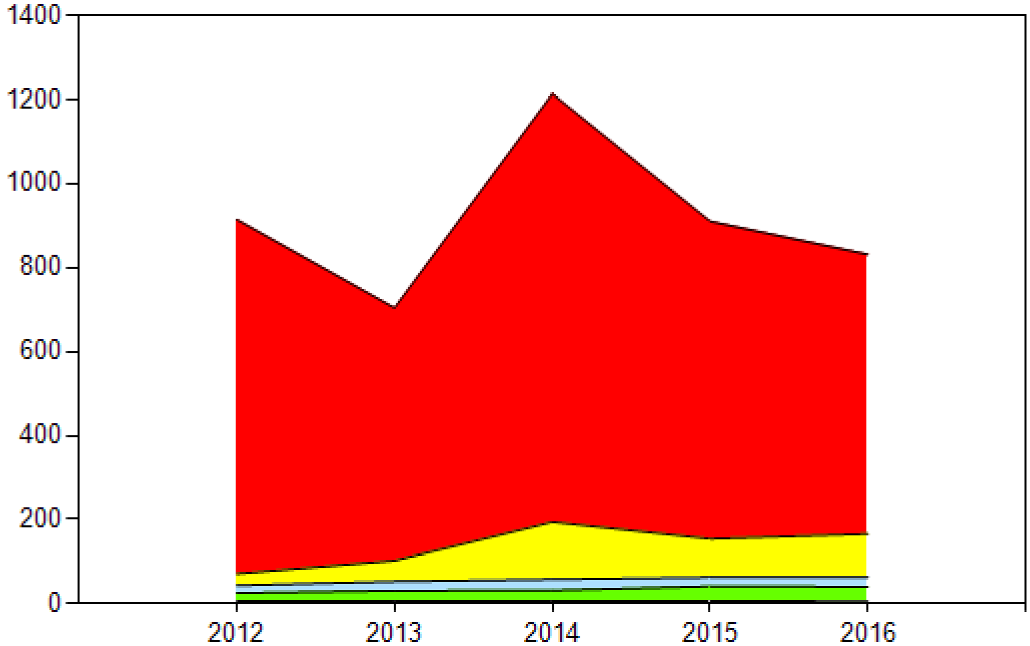


Graph 7-9: Region 2 CHIKM, Including All Events

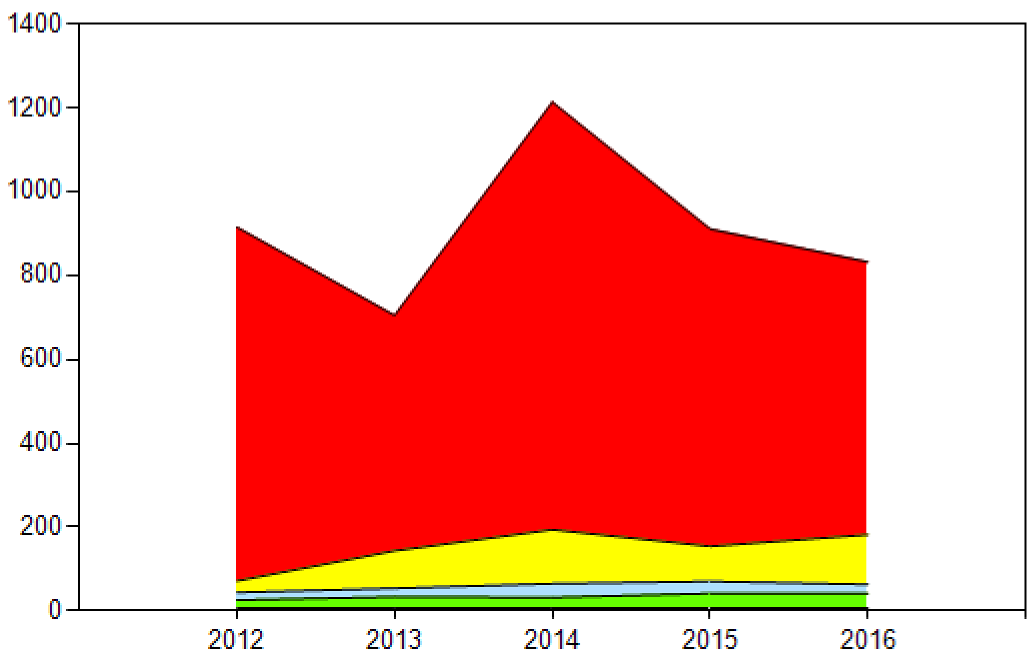


Graph 7-10: Region 2 CIKM, Excluding MPEs

Note: Quartiles include Canadian and International Utilities

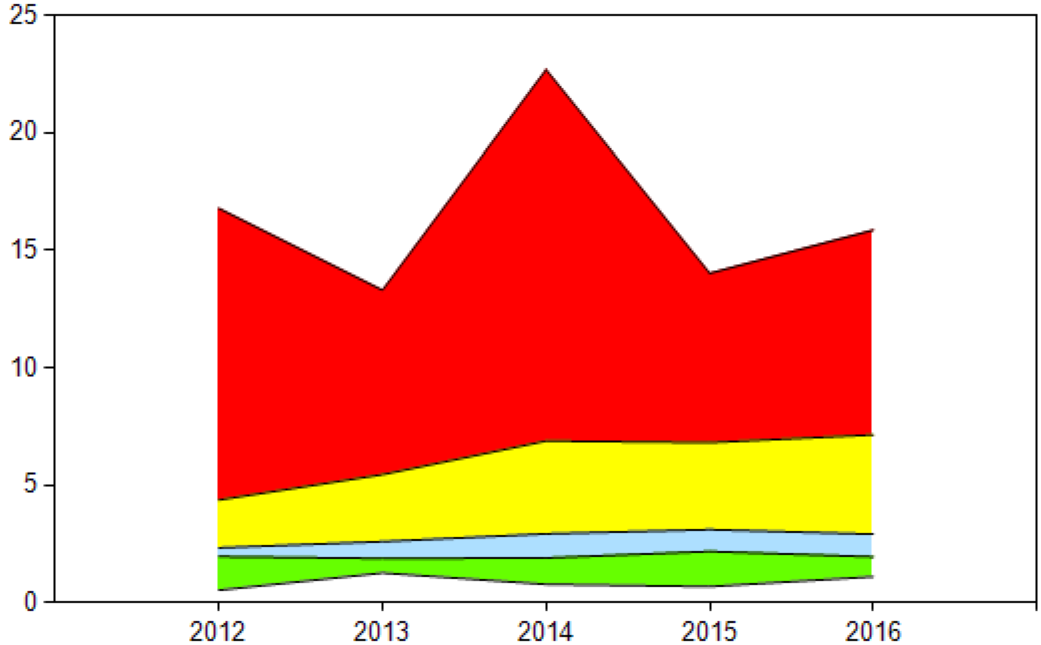


Graph 7-11: Region 2 CIKM, Excluding Significant Events

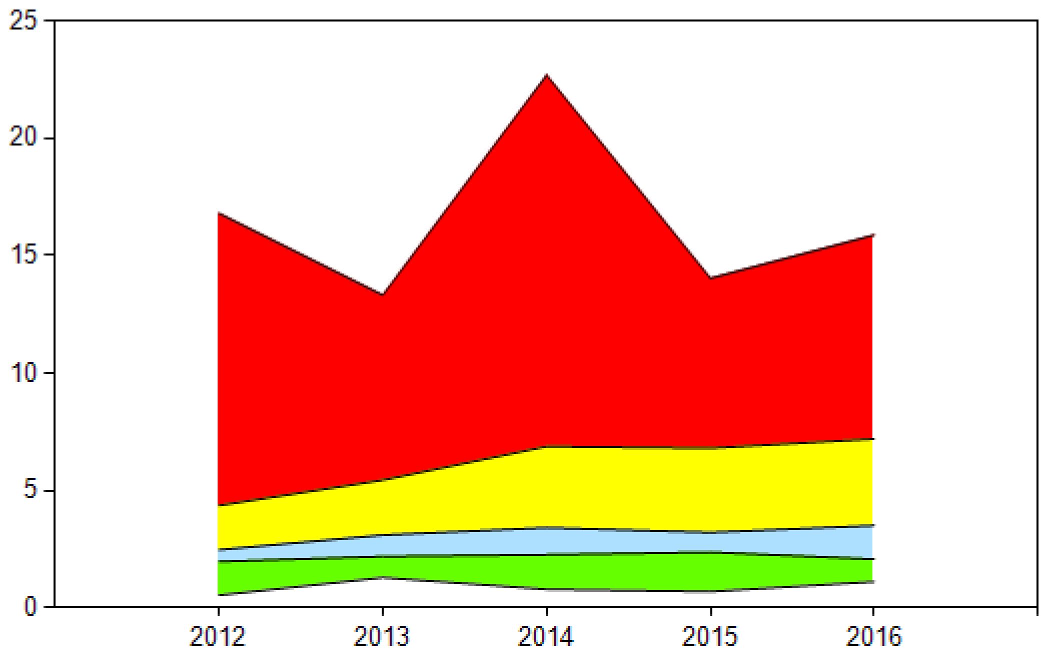


Graph 7-12: Region 2 CIKM, Including All Events

Note: Quartiles include Canadian and International Utilities

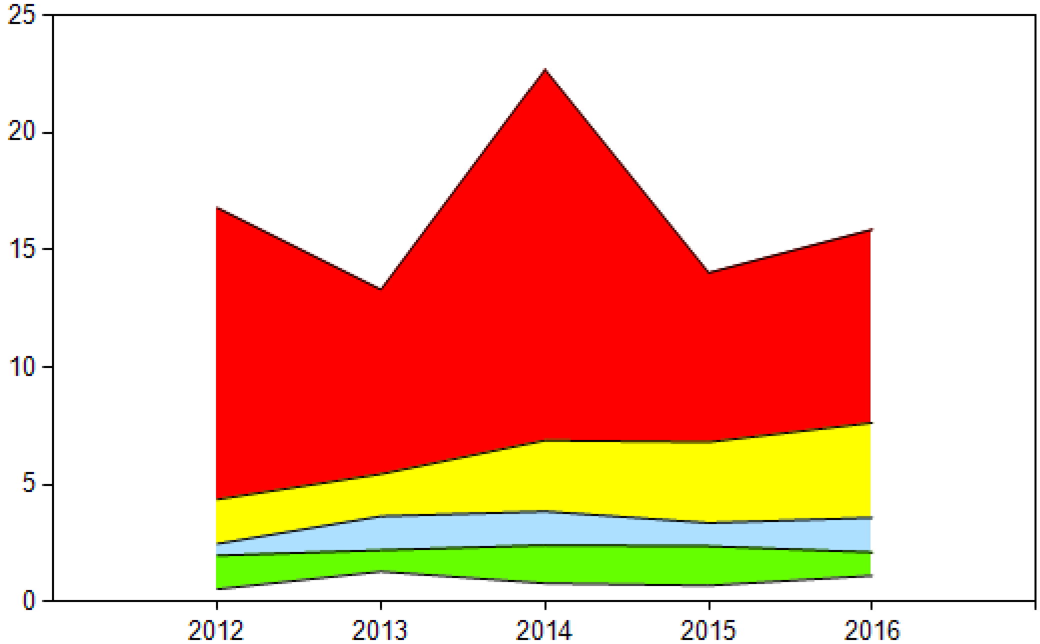


Graph 7-13: Region 2 SAIFI, Excluding MPEs



Graph 7-14: Region 2 SAIFI, Excluding Significant Events

Note: Quartiles include Canadian and International Utilities

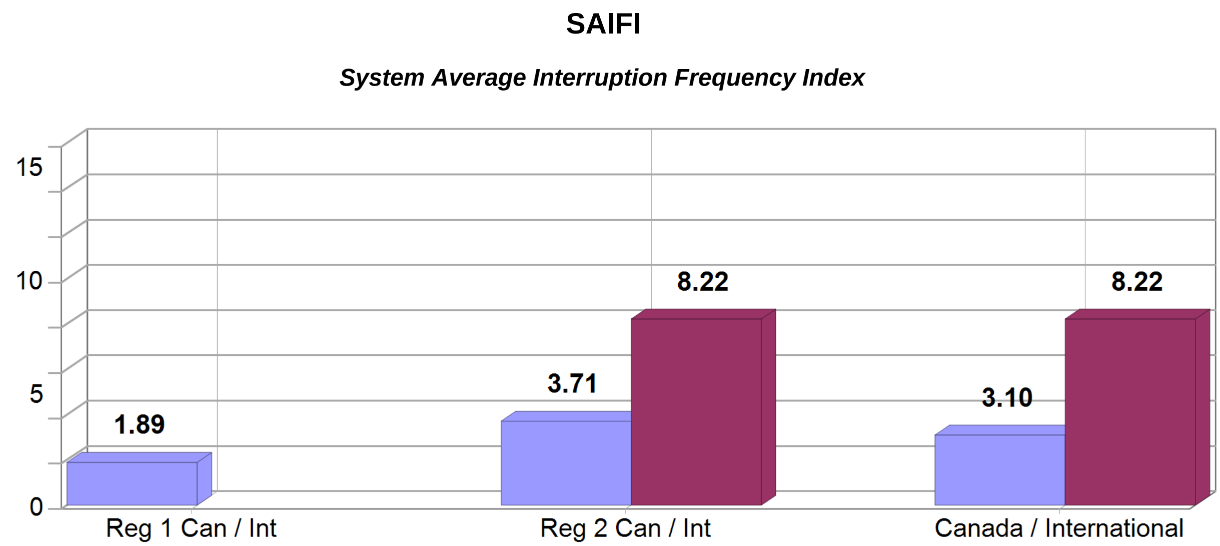


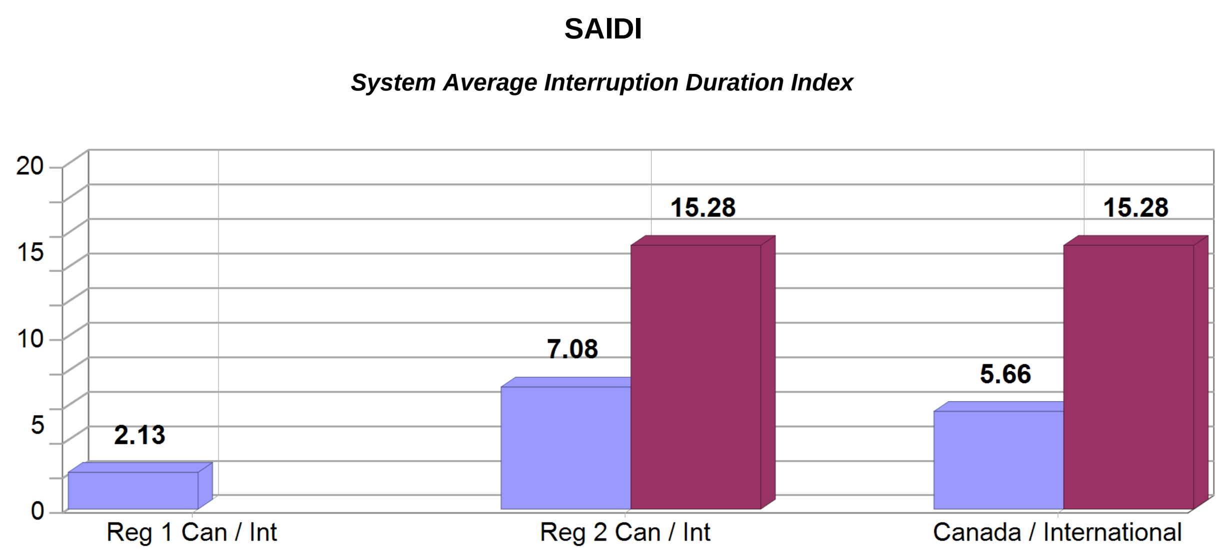
Graph 7-15: Region 2 SAIFI, Including All Events

8.0 SYSTEM INDICES FOR REGIONS

8.0 SYSTEM INDICES FOR REGIONS

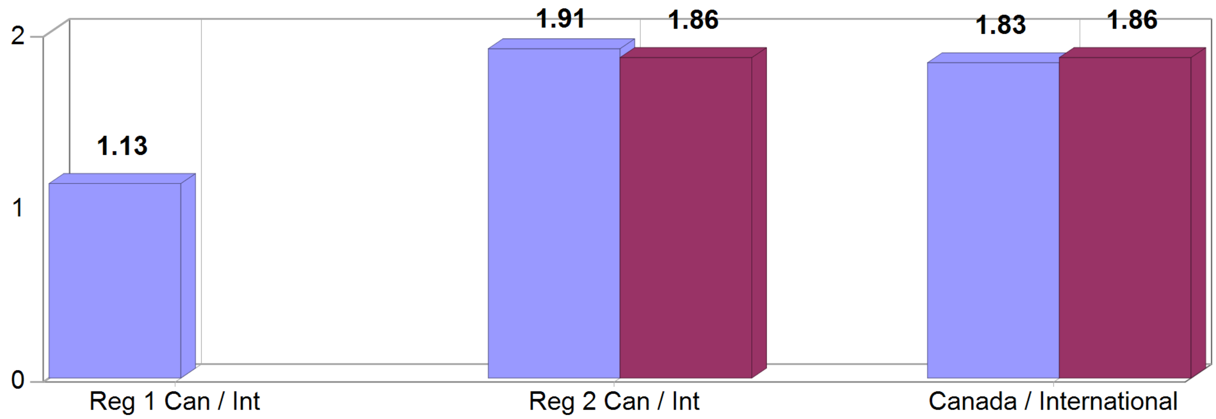
Graph 8.1 below shows the variations in the services indices of SAIFI, SAIDI, CAIDI, the Index of Reliability, CHIKM, CIKM for 2016 total Canadian and International data and by regions.



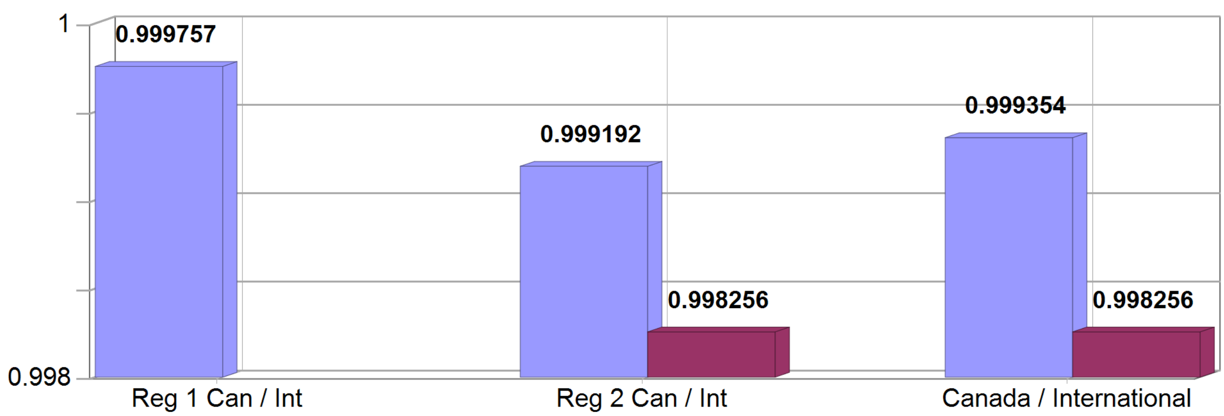


CAIDI

Customer Average Interruption Duration Index

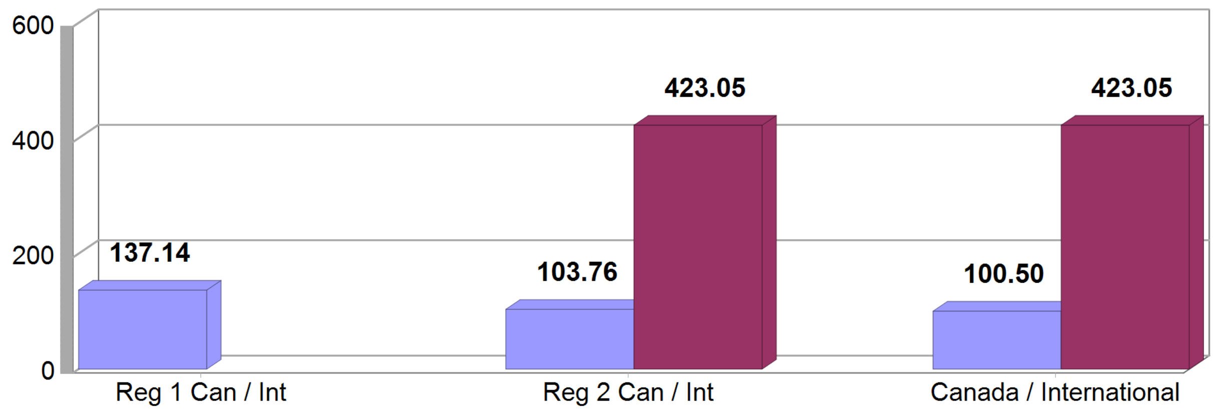


Index of Reliability



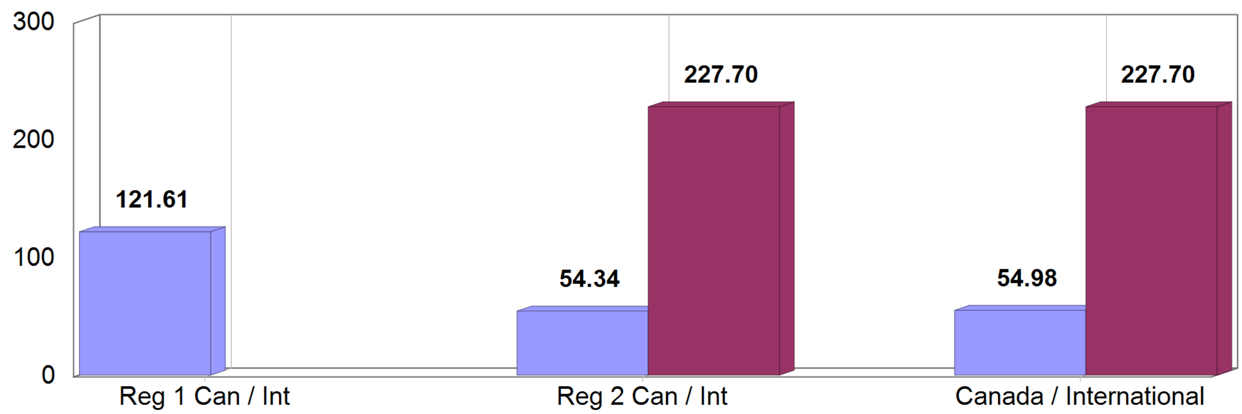
CHIKM

Customer Hour Interruptions per KM



CIKM

Customer Interruptions per KM



NOTES

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School Energy Coalition Interrogatory # 4

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
None

Interrogatory:
Please provide all materials provided to the Board of Directors for the approval of this application and the associated 2018-2022 budgets.

Response:
Please see the attached materials that went to Hydro One's Board of Directors in addition to the business plan documents provided as attachments to: Exhibit A, Tab 3, Schedule 1; Exhibit Q, Tab 1, Schedule 1; and Exhibit I-26-VECC-23. The materials provided are the materials which relate to this Application. Information which relates to other matters has been redacted from Attachment 5.

- Attachment 1: October 11, 2016
- Attachment 2: November 11, 2016
- Attachment 3: February 10, 2017
- Attachment 4: November 10, 2017
- Attachment 5: December 8, 2017

Filed: 2018-02-12
EB-2017-0049
Exhibit I-3-SEC-4
Attachment 1
1 of 21

Hydro One Limited/ Hydro One Inc.

Submission to the Board of Directors

Date: October 11, 2016

Re: Application for Distribution Rates 2018 to 2022

On March 3, 2017, Hydro One Networks Distribution ("HONI Dx") plans to file an application with the Ontario Energy Board ("OEB"), seeking the OEB's approval of a Custom Incentive Rate-setting Mechanism to establish rates for 2018 to 2022. The purpose of this Board meeting is to:

- Facilitate a discussion and obtain feedback from the Board relating to the preliminary Dx rate profile to be reflected in the planned application;
- Explain the rationale for the targeted March 3, 2017 filing date for the 2018 to 2022 Dx Rates Application; and
- Describe the form of the planned application.

We look forward discussing this submission with you at the board meeting on October 11th. In the interim, please feel free to forward any questions to myself or Michael Vels.

Yours sincerely,

Oded Hubert
Vice President - Regulatory Affairs

Hydro One Limited / Hydro One Inc.
Submission to the Board of Directors

Date: October 11, 2016

Re: Application for Distribution Rates 2018 to 2022

A. For Discussion - Preliminary Dx Rate Profile 2018 to 2022

Hydro One's management is seeking feedback from the Board on the rates profile that has emerged from the planning process for the 2018 to 2022 period.

The 2018 to 2022 application for Dx rates is expected to reflect the following key financial and rates metrics.

Table 1. Dx 2018 to 2022 Rates Profile ($M except where otherwise noted)

Date: September 28th, 2016	Distribution (Plan A - Recommended)					
	2017	2018	2019	2020	2021	2022
Capital Expenditures	660	805	850	787	792	898
In-service Additions	696	800	847	858	783	870
	OEB					
Rate Base	**7,190**	**7,741**	**8,207**	**8,683**	**9,290**	**9,709**
OM&A	593	587	596	605	614	623
Depreciation	390	421	439	453	479	499
Return on Debt	196	196	208	220	236	246
Return on Equity	252	272	288	305	326	341
Income Tax	49	60	62	62	70	75
Revenue Requirement	1,480	1,535	1,592	1,644	1,724	1,783
Acquired LDCs OM&A Adder	-	-	-	-	9	10
Rate Riders	11	26	26	26	26	26
Other revenue impacts	(52)	(42)	(42)	(41)	(42)	(42)
Rates Revenue Requirement	**1,440**	**1,520**	**1,577**	**1,629**	**1,719**	**1,778**
Rate Increase Required, excl Load		**5.6%**	**3.7%**	**3.3%**	**5.5%**	**3.4%**
Estimated Load Impact (Preliminary (August Load Forecast)		1.7%	-0.2%	-0.7%	-2.5%	-0.6%
Rate Increase Required		**7.3%**	**3.5%**	**2.6%**	**3.0%**	**2.8%**
Estimated Total Bill Impact (R1 customer - 30%)		**2.2%**	**1.1%**	**0.8%**	**0.9%**	**0.9%**

Assumptions:
Distribution 2017 rate base and revenue requirement per OEB approval
Forecasted ROE Rate of 8.77% used for Dx 2018-2022
Rate Base for acquired LDCs incorporated in 2021

The point at which Hydro One believes its corporate goals and customer interests are aligned or balanced, and appropriately reflected by the percentage increase in annual customer rates, is a matter of corporate strategy and informed judgment. The metrics set out above reflect the following factors that were considered to affect a balancing or alignment of competing interests, being low customer rates, appropriate system investments and Hydro One's business objectives.

Table 2. Dx Business Objectives

Business Objective	Description
Customer	• Improve customer satisfaction. • Engage consistently and proactively with customers. • Ensure investment plan reflects customer needs and preferred outcomes.
Safety	• Drive towards an injury free work place.
Employee	• Achieve and maintain employee engagement.
Reliability	• Maintain or improve level of distribution system reliability relative to distribution peers.
Environment	• Sustainably manage the company's environmental footprint.
Cost Control	• Actively control and lower costs through OM&A and capital efficiencies.
Public Policy Responsiveness	• Ensure compliance with all codes, standards and regulations.
Shareholder Value	• Achieve the ROE allowed by the OEB.

In making this assessment, Management considered a number of factors. These factors are set out below and include:

1. Output from a customer engagement process;
2. Analysis of two alternative investment planning scenarios ("Plan A - Recommended" and "Plan B – Not Recommended");
3. Attribution of the distribution rate profiles in each investment planning scenario;
4. Hydro One Limited consolidated financial outlook; and
5. Prior regulatory determinations of the Ontario Energy Board.

1. **Output from a customer engagement process:** HONI Dx engaged Ipsos to assist with the design and execution of a comprehensive customer engagement process. The purpose of the engagement process was to secure the input/feedback necessary to prepare an investment plan and rate application that considers Hydro One's customers' needs and preferences. The customer engagement process produced the following key findings that are more supportive of a lower rather than higher investment plan:

– **Keeping costs as low as possible is customers' top priority**. This preference is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. Many customers believe that total electricity costs are approaching unaffordable levels.

– **Maintaining reliable electricity service is consistently a second priority to cost**. Power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, is the primary concern of commercial and industrial customers. Some large customers have capacity challenges and want more access to power in order to grow their enterprises. Customer service improvements are not something for which customers are willing to pay higher rates.

– **Large customers are more concerned with the reliability of service** they currently receive than residential and small business customers. However, although this group of customers is more inclined to value better reliability, they are not willing to entertain the corresponding rate impact. (Note: this is a significant difference between the feedback received from Transmission customers where generally, reliability and reliability risk was a higher priority than cost control).

– **All large customer segments prioritize the renewal program that focuses on replacing equipment that affects reliability** ahead of other options for improving reliability. Other options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages.

– **Willingness to accept a rate increase to maintain and improve service level is limited**. The majority of residential and small business customers are unwilling to accept higher rate impacts for better reliability; large customers generally accept that investments are needed; however they expect HONI Dx to exhaust all operational efficiencies before raising rates. At present, there is limited acceptance of any of the illustrative rate impact scenarios, even to maintain the current levels of reliability and service.

Management is aware of and has carefully considered the consequences of pursing an investment plan that is largely inconsistent with the outcome of the customer engagement process. It is important to note that for the 2018 rebasing year, approximately 50% or 3.5% of the rate increase in both investment planning scenarios is not within the company's control as it is driven by load changes or settlement of existing regulatory accounts. In addition, the average differential rate impact for the remaining four years of the rate-setting term is about 0.5% and 0.2% expressed on a total bill basis.

2. Analysis of two investment planning scenarios:

Two investment planning scenarios have been considered after the completion of the customer engagement process: Plan A - Recommended and Plan B – Not Recommended.

Plan A – Recommended: this investment plan reflects a portfolio of appropriately paced investments that achieve an optimal balance between cost effectiveness, responsiveness to certain identified customer needs and preferences, asset requirements and business objectives. In this plan, Hydro One is proactively investing in system renewal to address the reliability and power quality concerns of its customers. It increases the number of:

- Pole replacements, distribution station refurbishments, and submersible cable replacements to address the poor results of condition assessments; and
- Mobile unit substations to reduce customer interruptions due to planned maintenance and refurbishment activity.

The plan also includes investments that are designed to improve customer satisfaction, and enable productivity and efficiency improvements to lower OM&A costs.

Plan B – Not Recommended: this investment plan reflects a portfolio of capital investment that ensures compliance with applicable codes/regulations/laws and addresses certain reliability and customer needs; however it presents limited opportunities for productivity and reliability improvements. Investment in renewal capital is less than that in Plan A – Recommended, with the result that there is incremental risk of customer interruptions and a higher number of costly unplanned replacements. In addition, this investment plan puts at risk the company's ability to implement various enabling IT enhancements that are designed to result in productivity savings or improved customer satisfaction. Productivity savings are reflected in this investment plan; however the risk that these savings are not achieved is higher than in Plan A – Recommended.

The annual capital expenditures associated with each plan are set out graphically in Figures 1 and 2. The single largest investment in each of the two plans is the Integrated System Operating Centre which has a total cost of $130M. The cost of the facility is allocated 50/50 between Transmission and Distribution, with the Transmission portion of the Centre included in the current Tx rate application that is presently before the OEB.

Hydro One is planning to proceed on the basis that Plan A – Recommended will be included in its Dx application for rates.

Figure 1. Plan A - Recommended

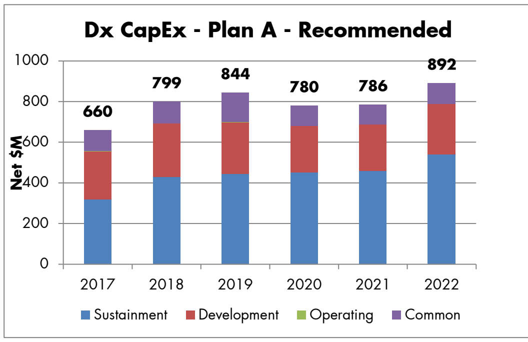
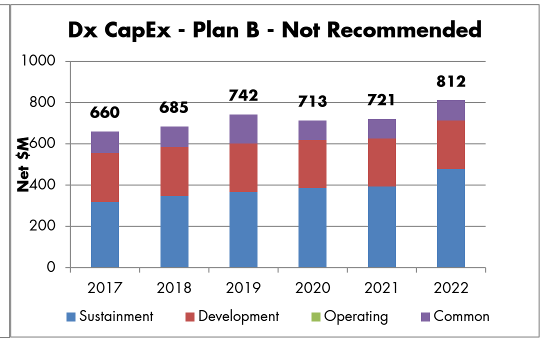


Figure 2. Plan B – Not Recommended



The average annual difference in investment between the two plans is $85 million. The rate impact of each investment plan is set out in Table 3. The principal drivers of Dx rates over the investment term are more fully analyzed in Table 6.

Table 3. Rate Impact – Plan A - Recommended and Plan B – Not Recommended

Plan A - Recommended	**2018**	**2019**	**2020**	**2021**	**2022**	**Average**
Rate Increase Required	7.3%	3.5%	2.6%	3.0%	2.8%	3.9%
Estimated Total Bill Impact (R1 customer – 30%)	2.2%	1.1%	0.8%	0.9%	0.9%	1.2%
Plan B – Not Recommended						
Rate Increase Required	6.2%	3.2%	2.5%	0.8%	2.6%	3.4%
Estimated Total Bill Impact (R1 customer – 30%)	1.9%	1.0%	0.7%	0.8%	0.8%	1.0%

As set out in Section C of this document, the OEB has implemented a Renewed Regulatory Framework for Electricity Distributors ("RRFE") for rate-setting purposes. Pursuant to the RRFE, the OEB requires that distributors substantiate applied-for capital budgets in terms of the performance outcomes of the RRFE: (i) customer focus; (ii) operational effectiveness; (iii) public policy responsiveness; and (iv) financial performance The RRFE Outcomes associated with Plan A – Recommended are set out in Table 4.

Table 4. RRFE Outcomes – Plan A - Recommended

RRFE Outcome	**Description**
Customer	• Investments are paced to avoid potential catch-up in future investment periods. • Identified needs and preferences of industrial customers for reliability and power quality improvements are addressed. Investments are made on a case-by-case basis using individual feeder performance metrics, rather than system-wide SAIDI/SAIFI performance statistics. • Worst performing feeder program for outlier management to be implemented on mass market customer feeders. • IT system investments promote the customer experience and achieve operational efficiencies. Initiatives include: web redesign and investments to improve customer bill comprehension and to improve visibility of customer energy usage, thus enhancing customers' ability to conserve based on visible

	consumption patterns. • Investments to improve customer services to put the "Customer First" will result in improved customer satisfaction and improved reliability and efficiencies in the call center. Overall the plan forecasts to improve the Customer Satisfaction survey result by approximately 13%. • Targeted reduction in manual meter reads of approximately 43,000 per year over the plan, enabling more timely and accurate Time-Of-Use bills. • eBilling is forecast to increase by approximately 15% over the term of the investment plan, resulting in significant savings in postage costs.
Operational Effectiveness: Productivity	• Productivity enabling investments will allow Hydro One to mitigate OM&A cost increases that would otherwise been included in the plan. • Investments in Customer Service, Work Management, Finance, Human Resource, Supply Chain systems enable higher work productivity and therefore lower the unit costs of these operations. Investment in plant maintenance, planning and scheduling will improve overall infrastructure reliability, reducing the number and duration of outages. • Standardization of work management for Provincial Lines, Stations and Forestry will be developed using SAP's mobile capabilities, with a commitment to achieve a minimum 5 percent productivity gain and annual savings of $12M. • Investments in Smart Meter Infrastructure enables remote disconnect/reconnect capabilities, with estimated savings of $3M per year. The remote disconnect/reconnect meters will deliver an additional $1M of annual OM&A savings over the planning period for Vacant Premise orders. • Vegetation Management programs have targeted SAIFI (interruption frequency) improvements primarily due to lower expected numbers of tree contacts, with investment focused on critical cycle clearing. • Fleet Services has struck an optimal balance between capital and maintenance expenditures. Each further reduction of $1M in capital will correspondingly increase OM&A by $60K and incur 205 hours of fleet downtime.
Operational Effectiveness: Safety	• Reduces the public safety risk of 'shock in water' incidents by replacing submarine cables with shoreline exposure over a 10 year period. Approximately 220 cables per year, representing 2% of the total fleet, are targeted for replacement.
Operational Effectiveness: Reliability	• System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) are forecast to improve by approximately 2% to 3% versus current levels of 3 outages per customer and 2.5 hours per event over the term of the investment plan. • Distribution system modernization will support the above improvements to reliability. • Trouble Calls and Storm Damage are budgeted at the four-year historical average to ensure sufficient funding for anticipated outages and power

	interruptions. • Adequate pacing of replacement levels of wood poles; about 83,000 poles representing 5%of the total fleet are currently in a deteriorated condition and must be replaced in a paced manner in order to manage renewal volumes. At the end of the investment term, the backlog of poles requiring replacement will be reduced slightly, thus achieving the proper pace of replacements to avoid future step changes in work volumes. Network Operating Division maintains its control room, system and tools to achieve an availability standard of 99.97%, ensuring reliability and availability. • Fleet vehicle levels are maintained to manage potential delays in the response time to unplanned incidents, such as trouble calls and storms, mitigating the negative impact on SAIDI. • Distribution station failures are reduced by setting station refurbishments at the level required to maintain system reliability at the current level, while addressing load requirements and aging asset demographics. Line Components that require replacement based on condition assessments will be remedied on a planned rather than unplanned basis. This will reduce costs and improve reliability.
Public Policy Responsiveness	• Distribution Modernization supports the Green Energy Act and Conservation First framework by enabling the connection of renewable resources, improving operational flexibility and promoting conservation. • Deliver timely and accurate bills to meet/exceed customer and regulatory expectations, reducing the number of estimated bills. • Lower unit costs by reducing manual meter reads.
Public Policy Responsiveness: Environment	• The Polychlorinated Biphenyl (PCB) Replacement strategy enables compliance with federally mandated environmental requirements to eliminate all contaminated units by 2025.
Financial Performance	• Productivity initiatives and strategies have been identified to drive sustainable and continuous improvements in cost performance and will be implemented over the investment term. Three work streams have been targeted: OM&A, Procurement, and Operations and Maintenance. Value realization for several key initiatives is dependent upon targeted investments in Information Technology (IT) and realization of Procurement savings.

Some of the key risks (by RRFE principle) involved with reducing funding to the level in "Plan B – Not Recommended" are set out in Table 5.

Table 5. RRFE Outcome Risks Associated with Plan B – Not Recommended

RRFE Outcome	Description
Customer	• Asset replacements would fall behind targeted levels, increasing the likelihood of unplanned equipment outages that cause customer interruptions, higher replacement costs than a planned replacement and a

	future "step change" in asset renewal volumes. • Network Operating portfolio reduces funding for investment in Outage Response Management System (ORMS) enhancements, which may delay customer restoration improvement initiatives.
Operational Effectiveness: Productivity	• Realization of savings projections and unit cost reductions are at risk due to reduced funding levels for IT improvements. • Lower expenditures in Fleet services will result in reduction of heavy equipment replacements of up to 13 units per year which will increase the risk of downtime hours; that will cause delays in work programs, impacting costs and performance. • Facilities would not be able to support the work program effectively (e.g., not investing in fleet garages will lower utilization rates) and constrain productivity achievements.
Public Policy Responsiveness: Environment	• Reduction in 2017 for PCB Transformer replacements requires a future program increase to meet the 2025 target of elimination of PCBs, with an increased risk of potential oil leaks. • Decreased work equipment replacements will reduce the equipment efficiency and limit reductions in Hydro One's carbon footprint.

3. **Attribution of distribution rate profiles in each scenario – 2018 rate increase relatively insensitive to investment scenario:** as set out in Table 6 below, the size of the rate increase in 2018 to 2022 in each scenario is largely attributable to Hydro One's capital investment program. Notably, approximately half of the 2018 rate increase is attributable to the true-up of the load forecast, differences from the prior year in amounts refunded to customers through rate riders, and changes in external revenues. This means that under both investment plan scenarios, there will be a minimum rate increase for 2018 of about 3.5% that is not within the control of HONI Dx.

   It is also important to note that significant productivity savings are reflected in the OM&A of both scenarios in the 2018 re-basing year, offsetting the upward pressure from inflation, regulatory costs, and planned, contracted labour-cost escalations. These cost and productivity initiatives reflect lower pension costs, process improvements associated with IT investments, and other organization-wide initiatives.

Table 6. Attribution of Distribution Rate Profile

Rate Increase Components Plan A - Recommended	2018	2019	2020	2021	2022	Average
Not in Hydro One's Control						
Estimated Load	1.7%	-0.2%	-0.7%	-2.5%	-0.6%	-0.5%
Rate Riders	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
External Revenues - Other	0.7%	0.0%	0.0%	0.0%	0.0%	0.1%
	3.5%	-0.2%	-0.7%	-2.5%	-0.6%	-0.1%
Within Hydro One's Control						
OM&A	-0.4%	0.6%	0.6%	1.1%	0.5%	0.5%
Rate Base & Depreciation	3.5%	3.0%	2.7%	3.9%	2.6%	3.1%
Income Taxes	0.8%	0.1%	0.0%	0.5%	0.3%	0.3%
	3.8%	3.7%	3.3%	5.5%	3.4%	4.0%
Total Rate Increase	7.3%	3.5%	2.6%	3.0%	2.8%	3.9%

Rate Increase Components Plan B - Not Recommended	2018	2019	2020	2021	2022	Average
Not in Hydro One's Control						
Estimated Load	1.7%	-0.2%	-0.7%	-2.5%	-0.6%	-0.5%
Rate Riders	1.1%	0.0%	0.0%	0.0%	0.0%	0.2%
External Revenues - Other	0.7%	0.0%	0.0%	0.0%	0.0%	0.1%
	3.5%	-0.2%	-0.7%	-2.5%	-0.6%	-0.1%
Within Hydro One's Control						
OM&A	0.0%	0.6%	0.6%	1.2%	0.6%	0.6%
Rate Base & Depreciation	2.1%	2.6%	2.5%	3.5%	2.4%	2.6%
Income Taxes	0.7%	0.2%	0.1%	0.4%	0.3%	0.3%
	2.8%	3.4%	3.2%	5.1%	3.2%	3.5%
Total Rate Increase	6.2%	3.2%	2.5%	2.6%	2.6%	3.4%

4. **Hydro One Limited consolidated financial outlook:** as set out in Table 7 below, Hydro One Limited's financial outlook does not materially change between investment scenarios. Earnings per share and dividend metrics over the 2018 to 2022 rate period are not sufficiently differentiated to favour one investment plan over the other. The CAGR of EPS over the 5-year rate setting period for both scenarios is consistent with the 4 to 6% range targeted by most comparable publicly traded utilities and the expected dividend and dividend payout ratios are nearly identical. Debt levels would continue to be in the targeted range under both investment plans.

Table 7. Hydro One Limited Consolidated Financial Outlook

Metric (2017 to 2022)	Plan A - Recommended	Plan B – Not Recommended
CAGR Net Income	6.5%	6.1%
CAGR Earnings per Share	6.5%	6.0%
CAGR Dividends Per Share	5.0%	5.0%
Average Dividend Pay Out	69%	69%
Average Debt to Rate Base	64%	63%

5. **Regulatory determinations:** Management was informed by the rates approvals associated with the Custom IR filings by other utilities, including Toronto Hydro Electric System Limited and PowerStream Inc., and 4th Generation (or Price Cap IR) applications by other utilities, such as Milton Hydro Distribution Inc. These decisions have been used to:

- Identify the decision framework that the OEB will use to assess whether the form and incentives embedded in Dx's planned application for 2018 to 2022 rates are consistent with the RRFE;

- Provide guidance with respect to the overall preliminary Dx rate profile for 2018 to 2022; and
- Provide guidance with respect to evidentiary requirements to support the applied-for investment plan; specifically productivity, outcomes and key performance metrics.

For example, based on the Reasons for Decision relating to the Milton Hydro Distribution[1] application, it is evident that the OEB is increasingly likely to use benchmarking and other reference tools to determine the appropriateness of the applied-for increase in distribution rates, including the change in rates between the bridge (2017) and rebasing year (2018).

These metrics include:

- use of an econometric model to externally and internally benchmark utility productivity on a historical basis;
- use of the same model to predict forecast costs over a single period, being the rebasing year; and
- use of other comparables, as set out in Table 8 below. The OEB is likely to use these metrics to aid in its determination of whether the revenue requirements and the associated applied-for capital expenditure budgets are reasonable.

Table 8. HONI Dx Scenario Metrics versus Inflation and Load

Plan A - Recommended	
CAGR Revenue Requirement 2017 to 2022	4.3%
Percentage Change in Revenue Requirement 2022 versus 2017	23.5%
CAGR Rate Base 2017 to 2022	6.2%
Percentage Change in Revenue Requirement 2022 versus 2017	35.0%
Plan B - Not Recommended	
CAGR Revenue Requirement 2017 to 2022	3.9%
Percentage Change in Revenue Requirement 2022 versus 2017	21.0%
CAGR Rate Base 2017 to 2022	5.3%
Percentage Change in Revenue Requirement 2022 versus 2017	29.4%
Inflation	
Annual Inflation Assumption	1.50%
Percentage Change in Inflation	7.7%
Load	
CAGR Load	-0.5%
Percentage change in Load	-2.3%

The principal reason that Hydro One's Revenue Requirement is increasing at a higher rate than inflation is due to the need to invest in assets that are increasingly deteriorated and at the end of life, requiring investment in excess of annual depreciation.

[1] Milton Hydro Distribution Inc. Decision and Order. Ontario Energy Board EB-2015-0089. July 28, 2016.

B. March 3, 2017 Target Filing Date

The targeted filing date of the application is March 3, 2017. The decision to file the application on this date reflects the following considerations:

- The OEB normally requires seven to nine months to consider a typical cost of service application; however 10 to 12 months is more of the norm in relation to the time required to hear and consider an application for Custom Incentive Rates, due to the additional complexity that accompanies this type of application.

  As described in the next section, HONI Dx intends to file an application for Custom Incentive Rates effective January 1, 2018, and it is expected that the rate-setting structure will have a number of custom features, including a custom capital factor and an additional mechanism associated with the previous acquisition of Norfolk Power Inc., Haldimand County Utilities Inc., and Woodstock Hydro Services Inc. Given these custom elements, it may take in excess of 12 months for the OEB to fully litigate HONI Dx's application for Custom Incentive Rates.

- HONI Tx is expected to file a multi-year application for incentive rates beginning January1, 2019 in the first quarter of 2018. Asset planning and customer engagement processes, benchmarking and productivity studies, and other associated regulatory studies and processes will need to be initiated in early 2017, if a regulatory application is to be filed and considered by the OEB, such that approved rates are in place and effective January 1, 2019. A delay in the preparation and subsequent filing of the 2018 to 2022 Application for Custom Incentive Rates will have the effect of "crowding out" the Tx application process.

C. Form of the Planned Application for 2018 to 2022 Distribution Rates

In Ontario, the OEB is required by its governing statute, the *Ontario Energy Board Act, 1998* (the OEB Act), to give rate-regulated utilities the opportunity to recover their reasonably incurred costs of providing utility service. The OEB Act gives the regulator wide latitude in the tools that is uses to fulfil this requirement, allowing it to use "any method or device" to set utility rates. In the case of Ontario-based electricity distribution utilities, the OEB adopted an incentive mechanism for rate-setting purposes in 2000 (1st Generation IR).

Incentive Regulation

An incentive rate or "IR" regime is one in which "market-like incentives are created for the utility to operate in an efficient and effective manner for the customers' benefit, reducing the need for continuous and detailed regulatory scrutiny of utility operations"[2]. A well designed IR

[2] Discussion Paper on Rate Regulation in Ontario. Pacific Economics Group, LLC, ICF Consulting; and Exel Energy Group. September 2004. Page. 17.

approach seeks to achieve both productive and allocative efficiency. Productive efficiency is achieved by weakening the link between utility costs and approved rates, expressed on a unit basis. Allocative efficiency is achieved by the use of metrics to ensure that the services provided and outcomes achieved by the utility are valued by customers and demonstrate "value for money"; that is, services are provided by the utility for which the customer is willing to pay.

The OEB has continued to evolve its approach to incentive regulation – on October 18, 2012, the OEB released its *Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE).

Renewed Regulatory Framework for Electricity Distributors

The OEB's RRFE intends to provide alignment between a sustainable, financially viable electricity sector with customers' expectations for reliable service at a reasonable price. The OEB believes that emphasizing results, as opposed to activities, will result in better responsiveness to customer preferences, enhance distributor productivity, and promote innovation.

The RRFE is focused on driving four performance outcomes:

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved. Utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government; and
4. Financial Performance: financial viability is maintained and savings from operational effectiveness are sustainable.

The RRFE performance outcomes are to be achieved by three regulatory approaches:

1. Three incentive-based rate-setting options designed to incent continuous productivity improvement: (i) Annual Incentive Rate-setting Index – for distributors with limited incremental capital requirements; (ii) 4th Generation or Price Cap IR – suitable for most distributors; and (iii) Custom Incentive Rate-setting – suitable for distributors with large or highly variable capital requirements – HONI Dx will be selecting option (iii);
2. Five-year, consolidated asset plans to support rate applications; and
3. Performance measurement.

Previous HONI Dx Custom IR Decision

The planned HONI Dx application targeted for March 3, 2017 will be the second Custom Incentive Rate-setting application filed by HONI Dx with the OEB. The first application, filed on December 19, 2013 sought an OEB approval for distribution rates for a five year period, commencing January 1, 2015. Although HONI Dx applied for rates under the OEB's Custom IR framework, the application was characterized by HONI Dx as a "Custom Cost of Service", and as such the OEB determined that it "does not consider Hydro One's application to be sufficiently aligned with the objectives of the RRFE policy"[3]. As a result, the OEB approved rates for the period 2015 to 2017 on a cost of service basis.

In addition, the OEB made the following determinations[4]:

- The company's approach lacks the RRFE features designed to achieve a central policy objective of measuring performance and providing incentives for continuous improvement:

  - Inconsistency with outcome-based regulation as it relates to decoupling rates from costs and the use of external benchmarks of cost, output and service quality to reveal superior performance and encourage best practice;
  - Lack of externally imposed incentives to inform productivity and efficiency gains;
  - Weak benchmarking evidence to demonstrate year-over-year trended performance or performance versus that of other comparable utilities;
  - Limited prospects for continuous improvement; and
  - Absence of outcome measures that confirm or demonstrate value to customers.

- It is clear that thedistribution system is in need of investment and changes to system performance may not be immediately visible. However, in absence of an outcome measures to demonstrate performance improvement value to customers, another way to demonstrate value for customers is to bring forward unit cost metrics to demonstrate cost performance improvements.

The OEB expects HONI Dx's application for 2018 to 2022 rates to be fully compliant with the RRFE. The rate-setting approach to be reflected in the application is set out in Table 9.

Table 9. Key Features of the HONI Dx Rate-setting Approach

Feature	Description
Type of Rate-Setting Approach	Custom IR
Term	5 years: January 1, 2018 to December 31, 2022. Term is consistent with OEB RRFE requirement that the minimum term of a Custom IR be 5 years. 2018 – Rebasing or cost of service year 2019 to 2022 – Incentive rate years (IR years)* *2021 Rates to include acquired utilities

[3] EB-2013-0416 Decision Hydro One Networks Inc. Ontario Energy Board. March 12, 2015. Page 8.
[4] Ibid. Pages 9, 12-20.

Revenue Cap	The Revenue Cap is determined as: (1) the revenue requirement determined for the rebasing year (2018), adjusted by the Annual Adjustment Mechanism in each of the four successive incentive rate years, plus (2) the revenue requirement calculated by the Capital Factor.
Annual Adjustment Mechanism (1 + Inflation Factor – Industry Total Factor Productivity - Stretch Factor)	To be calculated in a manner consistent with the OEB approach in 4th Generation IR. The Annual Adjustment Mechanism is equal to: (i) **Inflation Factor** – based on 2-factor input price index (IPI) methodology that reflects Ontario's electricity industry (70% of annual % change in GDP-IPI and 30% of annual % change in Average Weekly Earnings); (ii) **Productivity Factor** – Ontario electricity industry Total Factor Productivity (TFP) which is currently set at 0%; and (iii) **Stretch Factor** (SF) – as determined by the OEB based on the OEB's Total Cost Benchmarking model. HONI Dx Distribution's current Stretch Factor is 0.6%. The Inflation and Stretch Factors will be updated annually, consistent with current OEB practice in 4th Generation IR. The Productivity Factor (TFP) will remain fixed over the Custom IR term. The Stretch Factor is updated annually by the OEB. Should HONI Dx's efficiency, as determined through the OEB's comparative cost analysis, improve during the term of the Custom IR, the Stretch Factor would decline. This means that HONI Dx's revenue will increase about 1.5% each year, assuming current inflation rates. Any ability for the company to limit the rate of cost increases to less than this amount will result in over-earning of its deemed ROE.
Treatment of Capital – Capital Factor	Costs associated with HONI Dx's capital program that are not recovered in base IR rates will be recovered through a Capital Factor. Costs to be recovered in the Capital Factor include incremental depreciation, cost of debt, cost of equity, and taxes. These are the specific costs that are related to capital. The factors relevant to the calculation of the Capital Factor are: mid-year rate base and assets placed in-service.
Deferral and Variance Accounts	HONI Dx's existing variance accounts, and associated rate riders, will continue in the normal course.

	New variance accounts that are likely to be required include: • Capital In-Service Variance Account; and • Earnings Sharing Mechanism (see below). Consideration is currently being given to a variance account for the costs associated with externally driven capital investment that is not anticipated in the Distribution System Plan.
Load Forecast	HONI Dx will estimate load for each year of the Custom IR term and file it in the application. It is intended that the OEB approve the load forecast for each of the 5-years and that the annual process to adjust IR rates will reflect the change in load for that year. Billing determinants (number of customers, kWh Consumption or kW Peak Load) would be updated annually to reflect the approved load forecast for each year. Consideration is currently being given to the potential use of mechanisms to reduce the risk related to the 5 year forecast. For example, HONI Dx could apply to update the load and customer forecast at the end of 2020, for rates in 2021 and 2022.
Earnings Sharing Mechanism (ESM)	An ESM is not a required feature of a Custom IR. However, Management believes that we will likely implement an ESM. HONI Dx is currently contemplating a sharing mechanism pursuant to which any earnings that exceed the regulatory ROE reflected in Custom IR rates by more than a pre-established threshold in any year of the Custom IR term would be shared 50/50 with customers.
Cost of Capital Parameters	Cost of equity and debt will be updated in 2018 (the rebasing year). However cost of capital parameters are not automatically subject to annual adjustment as part of a Custom IR application. HONI Dx will likely decide to apply to update the parameters on an annual basis, which will be done as part of the annual rate order process in the Incentive Rate years 2019 to 2022.
Capital In-Service Variance Account (CISVA)	HONI Dx does not currently have a CISVA, however it is expected that this account will be included, as it represents good practice, aligns the interests of the utility and customers by creating an incentive for the utility to only put in service the amount of capital that is reflected in the rates, and is consistent with HONI Tx. The features of a CISVA currently being considered include:

	i. Purpose to track the impact on revenue requirement of any in-service additions versus OEB-approved amount for each year of the Custom IR term; ii. The revenue requirement associated with any under spending, will be disposed of on a cumulative basis at the end of the five-year term of the Custom IR Plan in 2023; iii. Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and iv. Account will be asymmetrical, meaning that should the in-service additions in any year exceed the OEB-approved amount for that period, no entry is made in the variance account and no amount is recoverable from ratepayers.
Treatment of Unforeseen Events (Z-Factor Claims)	Consistent with the OEB's RRFE, existing OEB policies in relation to unforeseen events will apply. HONI Dx has the ability to include in an application a request to recover costs associated with unforeseen events that are outside the control of a distributor's ability to manage. The cost must be material (in-excess of $2 million) and its causation clear. The materiality thresholds must be met on an individual event basis in order for the distributor to apply for recovery of the relevant costs.
Off-Ramps	A regulatory review may be triggered if a distributor's earnings are outside of a dead band of +/- 300 basis points from the OEB-approved return on equity.

Table 10 highlights the key regulatory policy issues associated with the planned 2018 to 2022 Custom IR application for Dx rates.

Table 10. Regulatory Policy Issues

Regulatory Policy Issue	Description
Status of Tx Application – Implication for Dx Application for 2018 to 2022 Rates	There is some risk that the OEB may not issue a Decision and Order on HONI Tx's application for 2017 and 2018 rates prior to the finalization of the structure and content of the HONI Dx application for 2018 to 2022 rates. There are a significant number of regulatory policy issues that are common to both applications. The issuance of a Tx Decision by the OEB that is inconsistent with the filing position on shared regulatory policy issues may cause the HONI Dx application for rates to be delayed.
Compensation	Consistent with the filing position for the Application for 2017 and 2018 Transmission Rates, LTIP, STIP, stock-based compensation costs and costs related to the Employee Share Ownership Plan should be recoverable in rates and are a component of normal total compensation. Four compensation

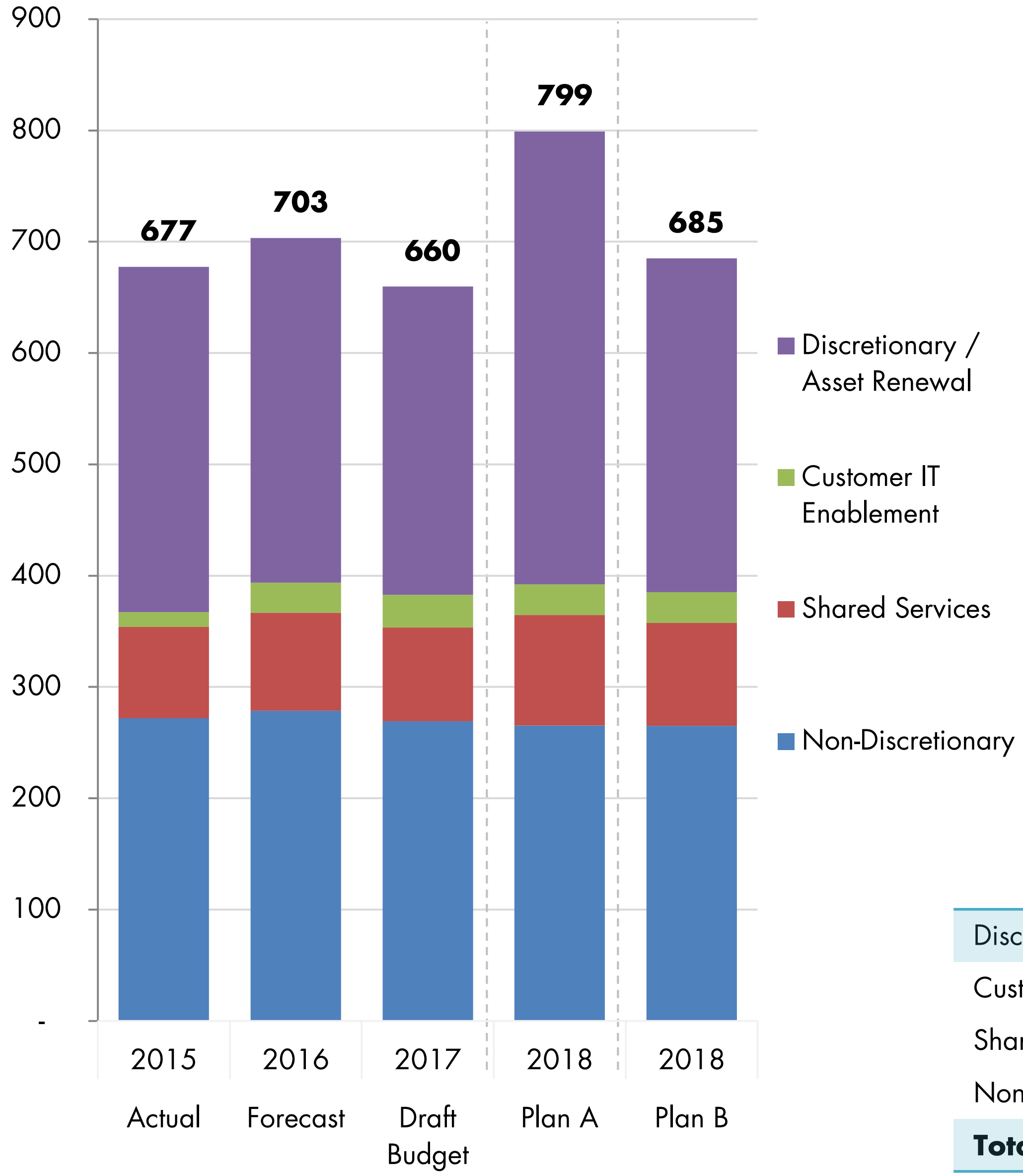
	issues will likely be tested during the proceeding: (i) size of total compensation "envelope"; (ii) composition of compensation costs; (iii) executive compensation; and (iv) whether Hydro One's OEB-approved Regulatory Cost Allocation remains appropriate.
Taxation Rates and Deferred Tax Asset	The application will reflect a combined Federal and Provincial income tax rate of 26.5% for ratemaking purposes. Consistent with the filing position for the Transmission Application for Rates, based on regulatory principles ("stand-alone" and "benefits follow costs") and guidance from previous OEB determinations, the shareholder should own the benefit associated with the deferred tax asset that arose from the IPO of the company.
Response to OEB-Mandated Studies	The OEB Ordered the completion of the following reports in order to inform it's assessment of HONI Dx's efficiency and productivity, and to assist with its assessment of whether applied-for costs are reasonable: • Total Factor Productivity (TFP) Study; • Total Compensation Study; • Vegetation Management Program and Trend Analysis; • Third-party Review of Dx's Distribution System Plan; • Pole Replacement Program; • Distribution Station Refurbishment Program; • Miscellaneous Service Charges; • Depreciation Study; and • Capital In-Service Additions. The implications and consequences of these reports will be fully reflected in HONI Dx' capital and operating plans. Strategies and actions to address identified areas will be comprehensively set out in the application and the pre-filed evidence.
Cost Efficiencies, Productivity and Performance Management	KPI's, performance metrics and outcome measurement contained in and resulting from the foregoing OEB-Mandated Studies are expected to be integrated into the company's performance measurement approach. As stated by the OEB in its July 28, 2016 Decision and Order for EB-2015-0089, utilities that objectively demonstrate measurable and sustainable continuous improvements in each of the RRFE categories can expect to have their test period revenue requirement requests approved without material disallowances. Measurement tools include: (i) productivity indicators: input/output metrics; (ii) KPIs: track how well you are doing versus what you said you would do; and (iii) Outcome measures: creating value for money or results that are valued by Customers.
Total Cost Benchmarking – Pacific	As set out by the OEB in the recent PowerStream Decision and Order, "the OEB has previously determined that both external benchmarking and

Economic Group (PEG) Model	internal benchmarking that tracks year-over-year productivity improvements are key in providing the confidence for long-term rate setting under the principles of the RRFE"[5]. The OEB has used an econometric model to externally and internally benchmark utility productivity on a historical basis. It is this model that benchmarks HONI Dx's annual cost performance, places the company in the 4th quartile, and results in the assignment of the 0.6% Productivity Stretch Factor. This model reflects the "average" Ontario utility and does not reflect HONI Dx's particular circumstances. The OEB has signalled its intention to use this model to predict forecast costs. New OEB filing requirements contemplate that HONI Dx will be required to run and file the output of this model, as it relates to the prediction of future costs, with the OEB at some point during the process to litigate the Custom IR application. HONI Dx will be required to provide evidence to support the difference or "gap" between econometrically predicted and applied-for costs, notably in the 2018 rebasing year. Although the OEB has also stated in a number of previous decisions "that it will use benchmarking as a tool to inform its decisions, but will not use it as a method by which to determine rates"[6], it appears that the weight the OEB places on the approach to establish the reasonableness of costs may be increasing.
Comprehensive Customer Engagement	HONI Dx has undertaken a comprehensive Customer Engagement process, consistent with the RRFE and the OEB's Filing Requirements for Electricity Distribution Rate Applications. At issue will be: (i) whether the Customer Engagement process meets the OEB's Filing Requirements; (ii) whether it was designed to identify customer needs and preferences; (iii) whether customer needs and preferences were identified; (iv) how identified needs and preferences informed the investment and operating plans set out in the pre-filed evidence; and (v) whether HONI Dx has adequately responded to the feedback from customers in a manner that produces tangible and measurable outcomes that are valued by customers.
Integration of Acquired Utilities	As described previously, the Integration of the Acquired Utilities will require that the rate base and OM&A costs of each utility be closed to HONI Dx's rate base and OM&A in 2021. The integration also requires new rate classes for residential and commercial customers. In addition, the OEB has mandated the following requirements in the Decisions and Orders in which it approved each of the MAADs applications relating to the Acquired Utilities.

[5] Ontario Energy Board. Decision and Order – PowerStream Inc. EB-2015-0003. August 4, 2016. Page 9.
[6] Ontario Energy Board. Decision and Order – Toronto Hydro Electric System Limited. EB-2014-0116. Page 19

	These requirements must be appropriately addressed in the Custom IR application.
Working Capital Allowance	The application will include a proposal for working capital as determined by a lead-lag study to be conducted by Navigant. The lead-lag study conducted for HONI Dx's current rates established a working capital requirement of approximately $250 million or 7.4% of total OM&A and Cost of Power amounts. Working capital is included in the calculation of mid-year rate base. A similar working capital requirement is anticipated for this application.

Investment Plan Scenario Comparison



Variance

- Plan B represents a 26% reduction of Discretionary / Asset Renewal Investment from Plan A levels (2018).

Discretionary / Asset Renewal

- Pacing of Asset Replacement/Refurbishment (Poles, Stations, Conductors)
- Technology Enhancements

Customer IT Enablement

- Billing and call centre enhancements
- Customer portal redesign

Shared Services

- Facilities sustainment
- Fleet and work equipment
- Technology infrastructure refresh

Non-Discretionary

- Third Party Relocations
- Storm Damage Response
- Customer Connections (Load / Generation)
- Metering
- Operating infrastructure

	Draft 2017	Plan A 2018	Plan B 2018
Discretionary / Asset Renewal	277	407	300
Customer IT Enablement	30	28	28
Shared Services	84	99	93
Non-Discretionary	269	265	265
Total	**660**	**799**	**685**

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: November 11, 2016

Re: Application for Distribution Rates 2018 to 2022

Attached for information is a summary of progress to date of the Distribution Investment Plan for the five year Distribution rate filing that is expected to be filed on March 3rd, 2017. The information is provided for feedback and input.

Significant inclusions/changes since the last Board meeting include:

1. A potential path to accomplish a 2018 rate increase of 5.4% (average of 3.4% over 5 years).
2. Detailed analysis of the effects of various options on customer bills and reliability.
3. Data on asset replacement rates and impacts on asset condition.
4. Analysis of productivity initiatives and outcomes on capital and OM&A
5. Summaries of customer feedback and the impact of such feedback on the plan.
6. Some history of OEB decisions to provide context on OEB expectations for this filing.

For the last several months, our teams have worked diligently to analyse trade-offs between customer and reliability impacts and customer bill impacts. In working to the optimum outcomes, we have considered overall reductions in the capital program, short-term capital reductions and more aggressive and targeted cost reduction to further reduce the overall bill impact arising from OM&A and corporate costs. Our focus was to find ways to reduce the average bill impact over the five year period, but also reduce the first year (2018) bill impact that already has non-actionable rate increases of 5.1% included. Our latest iteration has succeeded in adding only 0.3% in rate increases to the minimum bill impact in 2018.

The analyses provided are for feedback only. Management is not making a recommendation at this time. We will incorporate your feedback into the further analysis that we continue to perform, and expect to provide a final recommendation that will be included in a detailed business plan for Board approval at the December 2016 meeting.

We have attempted to keep the analysis as clear as possible, while providing relevant data.The subject is complex, and I would be pleased to discuss or answer questions of clarification before the meeting.

Yours sincerely,

Michael Vels
Chief Financial Officer

Date: November 11, 2016

Re: Application for Distribution Rates 2018 to 2022

A. CONTEXT AND BACKGROUND

Hydro One Distribution is in the process of preparing its rate filing for the five years beginning 2018. The process to finalise a major rate application is long, complex and iterative. The process is led by the Investment Management team, and involves accumulating and assessing a significant amount of information that supports decisions related to a system comprising $7.2 billion of assets (distribution rate base), over 1.3 million residential customers, a network of unique commercial and industrial customers and many competing priorities and needs. The process must incorporate direction, filters and adjustments at many points in the process.

The final recommendation must balance three competing, but equally important, factors. These are (i) the needs and preferences of our customers; (ii) the condition and reliability of the distribution system; and (iii) the effect on customer rates. None of these factors can trump the others, but a high quality application will evidence that management followed a sound process and used its best judgement to arrive at an optimum solution. The Ontario Energy Board (OEB) is acutely interested in how utility companies arrive at their conclusions.

For this application, we are very aware that customers are experiencing increasing and, in many cases, unmanageable electricity bills. These increases have been driven by many factors, including investments by generators, the need to invest in the deteriorated wires infrastructure and material changes in generation mix, from lower-cost coal to a higher reliance on cleaner and more efficient natural gas, nuclear and renewable generation. In addition, conservation and demand management initiatives have increased costs, on a per kWh basis, as predominantly fixed system investment is recovered over lower total Ontario demand.

Hydro One's approach has been shaped by: (i) a thorough investigation of opportunities to reduce our own costs and increase efficiencies before asking customers to pay more; (ii) direction of investment to support specific customer feedback on needs and preferences; and (iii) reducing or deferring investment levels to where increases in reliability risk can reasonably be justified by lower rates.

We have also taken into account previous direction by the OEB that acknowledged that our system is in need of additional investment, that planned reductions in reliability are not acceptable, and that investment in the system is desirable and required. We expect that there will be areas in our upcoming rate application where we will transparently outline that we have consciously reduced investments. For example, we may choose to reduce investments in 2018 to reduce rates in a year where customers may be experiencing bill impacts of up to 7.2% (total bill) due to continued increases in the price of electricity, but these decisions may have a negative effect on reliability risk and system condition.

We are very concerned about the effect of electricity costs on our most vulnerable customers. In some cases, bills for a low-density customer, even after the upcoming provincial rebates and existing support programs, can represent up to 18% of household net income. Studies presented to the OEB in the past have drawn the affordability line at 4-6% of household net income. Hydro One has about 71,000 customers that exceed the Statistics Canada Low-Income Cut-offs, with 3,500 of those experiencing electricity costs greater than 10% of net income. Our customer service and collections staff manages these customer impacts with as much empathy as possible and ensuring that these customers are fully availing themselves of existing support programs. Hydro One is also participating in OEB initiatives and studies, such as the First Nations rate recommendations, and directing community specific outreach to ensure that we are sharing and communicating available support programs and ways to reduce consumption with these customers.

As a rate regulated entity, we are not permitted to unilaterally resolve the rate design or social policy issues ourselves, and our focus on cost reduction, while helpful, is a small component of the total bill. Our primary focus is to help our customers deal with these impacts by using the resources at our disposal.

Finally, we have made decisions on information technology investments that will improve the customer experience. These decisions have had the effect of increasing the overall capital expenditures. Some of these investments are directed at cost efficiencies – for example moves to e-billing – but also include initiatives that will make it easier for customers to understand and manage their electricity consumption. We believe these initiatives are critical for a company that will clearly and visibly put the interests of its customers first.

B. PROCESS TO DATE

Starting early this year, and informed by work we completed on efficiency studies and business objectives, as described below, the Investment Management team finalised an asset investment plan that was focused on maintaining or improving reliability for customers, and was responsive to specific feedback received from our wide variety of customers. It includes significant efficiency improvements and focuses on reducing backlog of deteriorated assets over the five-year period. This plan resulted in a 7.1% Hydro One rate increase in 2018 (average of 3.8% over the five years), and forecasted improvement of approximately 6% in SAIDI and 4% in SAIFI related to our most significant areas of reliability risk over the five-year period. This "Plan A" was supported by detailed analysis and the outcomes following significant iteration and assessment of investment candidates and asset sustainment plans, and in many areas, a reduction of submitted candidate investments.

Investment Management, as part of their process, also requires Asset Owners to put forward, at a detailed level, lower levels of investment than the optimal recommendation which are considered when adjusting the plans to affect rate impacts and outcomes. Based on these detailed inputs and feedback and discussion with executive management, a further alternative investment "Plan B" was produced that reduces the rate impact in 2018 by 1%, to 6.2% (average of 3.5% over the five years), and also delivers a reliability improvement (approximately 3% SAIDI, 2% SAIFI), albeit not as much as Plan A.

These alternatives were further discussed with the Executive Leadership Team and, subsequently, the Board of Directors. These discussions generated exploration of further options to mitigate rate effects and, in particular, options to reduce the effect on customer rates in 2018 while maintaining responsible system investments and acceptable reliability and other outcomes.

Investment Management has further refined their work, and have outlined further options for consideration. Firstly, they assessed what would be required to achieve the lowest 2018 rate increase without material disruption to our operations. This is presented as the "Plan C" scenario, a top down assessment of alternatives, and is not fleshed out the same amount of detail as the Plan A and B scenarios. Our conclusion is that this option as a whole is not viable due to the material system and reliability impacts - degradation of approximately 2% in both SAIDI and SAIFI - that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition. However, a subset of options were also considered and are included in a scenario labelled here as "Plan B Modified." These options reduce the immediate impact on rates in 2018, to 5.4%. These options are indented to hold reliability risk constant, but may be justified by the positive effect on rates.

In the remainder of this note, we have outlined elements of the process followed and some more detail to illustrate the outcomes of each option. We are presenting these analyses for input and feedback, and will be finalising and presenting our recommendations for the Distribution rate filing in December, when we request approval of the Company's business plan. This business plan will then form the basis for the rate filing and related evidence, to be filed on March 3rd, 2017.

C. INVESTMENT PLANNING PROCESS

Hydro One's investment planning process is based on ISO 55000 principles, which are best practices for holistic Asset Management. The process takes identified asset needs, converts them into candidate investments, and then optimizes them based on their contribution to business objectives to yield an investment plan.

Business Objectives	Description
Customer 20 pts	• Improve customer satisfaction. • Engage with customer consistently and proactively.
Safety 20 pts	• Drive towards an injury-free work place. • Eliminate public safety incidents
Employee 10 pts	• Achieve and maintain employee engagement.
Reliability 15 pts	• Maintain current level of distribution system reliability relative to distribution peers.
Environment 10 pts	• Sustainably manage our environmental footprint.
Productivity 15 pts	• Actively control and lower costs through OM&A and capital efficiencies.
Shareholder Value 10 pts	• Ensure compliance with all codes, standards and regulations. • Achieve the ROE allowed by the OEB.

Initial guidance, in addition to these business objective weighting factors, was provided to planners in February 2016 to build their plans with the following considerations:

- Asset condition assessments
- OM&A limited to inflation, less a productivity factor as defined by the OEB (total increase no more than 1.5%). Very recently, in October, the OEB reduced the inflation factor by 20bps, which means we will need to update final work plans to reflect no more than a 1.3% revenue growth over the base year
- Rate base/asset growth originally limited to 4.2%, as in the previous business plan.
- 2017 spending/plans consistent with prior OEB decisions
- Cumulative In Service capital for 2016/17 consistent with OEB-approved levels
- Significant emphasis on how planned investments provide value to customers, reflect continuous improvement and improve reliability; and
- Plans must consider and incorporate the findings of the customer consultation process and productivity studies as information becomes available

Asset Owners design their investments to achieve the aforementioned objectives. The result is known in our internal process as "asset optimal level." As noted above, lower levels of investment are also requested – a.k.a. "Vulnerable." The lower level is described as a level that meets minimum compliance and health and safety requirements and is only tolerable for brief periods. At the lower level, asset failure is a distinct possibility.

After completion of manager review, the Investment Management team begins the optimisation process. This is when the rate impact of the plan is first determined. It is at this time that Hydro One introduces a financial constraint to adjust investment levels to align with acceptable customer rate impacts. Investments are eliminated based on weighted optimisation values, which, in our process, weight customer impact and worker and public safety as the highest values. Reliability and Productivity are the second highest values. These top four values comprise 60% of the total weighting. This year, greater emphasis was placed on customer-centric outcomes, including customer experience enhancements and productivity enablement for rate mitigation.

D. RATE APPLICATION FRAMEWORK

Under the current OEB framework for distributors, base distribution rate components, such as OM&A and depreciation, are set on a "cost of service" basis for a rebasing year (2018). This generates a revenue requirement for 2018. This base year revenue is then indexed by a (price or revenue cap) formula, comprised of an inflation adjustment (1.9%), less a productivity stretch (0.6%) factor for a total of 1.3%, and escalated annually from 2019 to 2022. The OEB inflation factor is updated and applies annually. Because 2018 costs form the base for the next four years of revenue, these costs are closely scrutinised. Any variances over this period, negative or positive, are to the utility's account.

The revenues calculated above recover approved costs and a steady state level of capital expenditures only. In addition capital program costs that are not recovered in base rates will be recovered through a custom Capital Factor that drives changes in rates in each year of the rate period, based on the quantum and timing of the capital program. Rate increases each year are highly responsive to the timing of capital placed in service. The revenue requirement generated by this capital factor is added to the revenue requirement outlined in the prior paragraph, for a total customer rate impact.

Past OEB filings: In 2012 (for 2013-2014), Hydro One sought OEB approval for substantial increases over historically approved levels for select investment areas, including wood poles and distribution stations, to address quality of service issues. Hydro One argued that without incremental investment, system reliability would be impacted as Hydro One would be unable to replace or refurbish assets prior to breakdown. Further, Hydro One argued that deferring planned replacement and refurbishment presents incremental system costs, as planned activities are less costly than simply replacing or refurbishing assets when they break.

In 2014, relative to other distributors in Ontario, Hydro One's average duration of outages (SAIDI) and average frequency of outages (SAIFI) for its distribution system were ranked worst and second-worst respectively among the 72 LDCs assessed, according to OEB scorecard data. The proportion of outages attributed to equipment failures has risen steadily. In response, Hydro One has placed an increased emphasis on renewal capital investments over the past several years. However despite increased investment, Hydro One's distribution system reliability did not improve from 2010 to 2014; the total number of power outages on Hydro One's distribution system increased by 11% over the period, with the most significant increase attributed to equipment failures.

In March 2015, Hydro One received OEB approval for a three year (2015-2017) custom cost of service application which included increased sustainment capital investment. Areas of focus included:

- stations component replacement and refurbishment to address station transformers and other components either approaching or beyond their expected service life;
- replacement of wood poles and line components that are either approaching or beyond expected service life; and
- replacement of a subset of wood poles showing signs of premature decay.

In its last distribution filing, Hydro One noted that that it would not be cost effective to improve its reliability ratings compared to other utilities and its customers would not want to pay the cost associated with the improvements. In its decision, the OEB stated it *"considers Hydro One's stance on its performance to be misplaced. Rather than argue that it would be too expensive to move up the ladder in comparison to those that are in the first, second and third quartile, Hydro One should be finding cost effective ways to improve its performance and provide evidence intended to convince the OEB that it has identified more appropriate benchmarks to which it can and will compare itself for continuous improvement tracking purposes."*

The Board goes on to opine regarding the ability to immediately impact system reliability, *"As previously noted, it is clear that the distribution system is in need of investment, and changes to system performance may not be immediately visible. Rather, system performance may erode without the investment."*

We will need to ensure that we have taken these directions by the OEB into account, or be very clear why we may have diverged from the direction in certain areas. We have concluded that a plan that further increases reliability risk is inappropriate and unlikely to be accepted by the OEB. We are also undertaking benchmarking studies to allow improved comparisons and thoroughly investigated options for productivity and efficiency improvements.

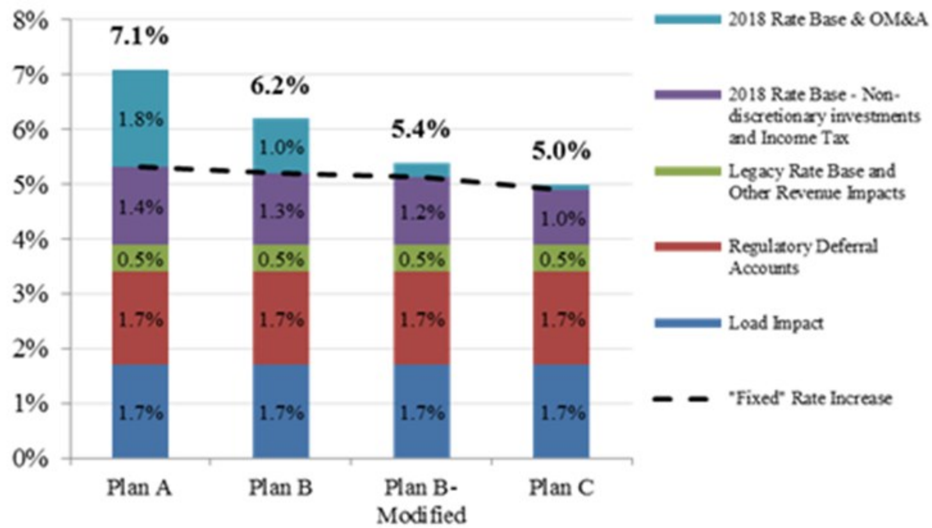
E. DESCRIPTION OF OPTIONS AND SCENARIOS

As discussed in this document, 5.1% of the 2018 rate increase is due to factors that cannot be impacted by Hydro One, and this is a "floor" on our ability to impact 2018 customer rates. This "floor" varies slightly across scenarios due to tax impacts.

Following further discussion related to customer rate impacts, Investment Management was directed to prepare a scenario that would limit 2018 customer rates and average rates for the five year period as much as possible while acknowledging various operational constraints. This was labelled as "Plan

C." Considering the unacceptable negative reliability and customer satisfaction outcomes over five years arising from Plan C, we then considered a range of more targeted options that trade off reliability impacts and impacts on rates. This is identified in this document as "Plan B Modified". Each scenario provides alternate outcomes and trade-offs between customer cost and preferences, company performance, and system risk over the 2018 to 2022 period, all of which the Executive Leadership Team will be considering as they arrive at a final recommendation. Bill impact amounts shown below are Distribution only (excludes Transmission) and have not been calculated as yet for Plan B – Modified.

Figure: 2018 Rate Impacts



	Plan A	Plan B	Plan B-Modified	Plan C
Average Annual Rate Increase (vs. 2017)	**3.7%**	**3.5%**	**3.4%**	**2.8%**
2022 – R1 Customer - Hydro One Rate (Dx) Impact (vs. 2017)	**$3.91**	**$3.42**	**TBD**	**$2.76**

As noted above, common to all three plans is a "fixed" rate increase for 2018 based on activities between 2014 and 2016 that cannot be practically influenced. After adding non-discretionary asset spend and taxation, the minimum rate increase for 2018 is approximately 5.1%, varying slightly between each scenario. These variances, and the effect on each plan, are further summarized in the waterfall charts below for Plan A and a modified Plan B, and can be explained as follows:

- *Load Impact*: As part of the design of the regulatory framework, a load forecast must be provided and the base year trued up for variances that, until then will have been borne by the utility (1.7%).
- *Regulatory deferral accounts* that have not been reflected in rates must be trued up according to OEB direction (1.0%).
- *Legacy Rate Base*: Hydro One has approximately $105M of additional work completed in 2015 above the prior revenue allowance that must be recovered in rates, referred to above as legacy rate base (0.5%).
- *Non-discretionary capital spending* that impacts the 2108 rate base include mandatory investments to connect load and generation customers, responding to storm damage and trouble calls, maintaining and enhancing the meter network, and sustaining operating infrastructure (0.5%).

As a result, in the 2018 rebasing year, between capital factors and OM&A, Hydro has approximately 2.4% of rate impact that can be adjusted to affect lower rates for customers. In all circumstances, Hydro One has built a plan where OM&A levels positively impacts rates by at least 0.4%, i.e., the contribution of productivity has reduced rates in excess of inflation, including productivity and cost reductions of approximately 2%.

Figure: 2018 Rate Impact of Plan A

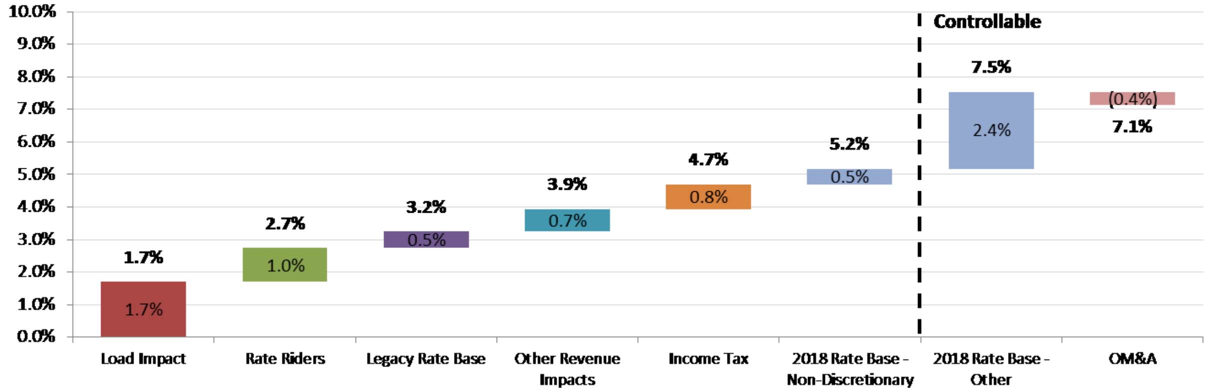
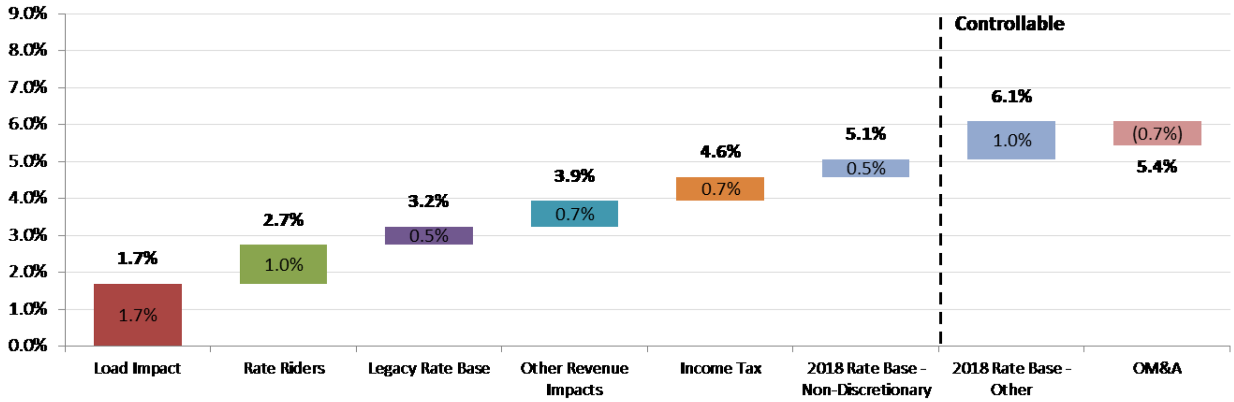


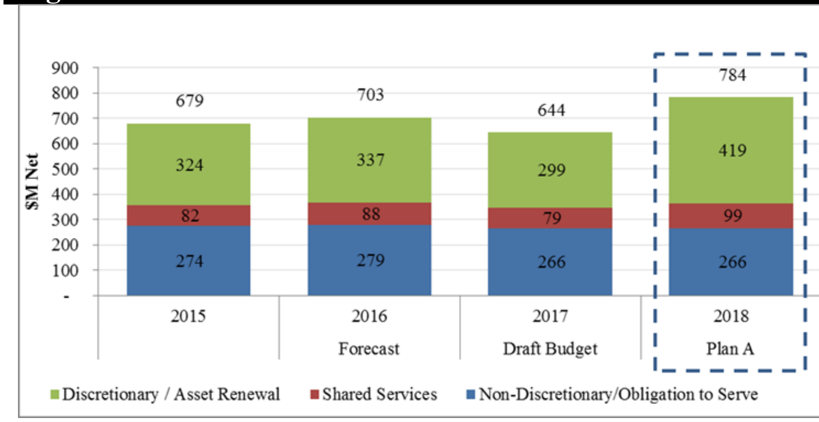
Figure: 2018 Rate Impact of Plan B - Modified



Summarised below is the capital profile of the primary scenarios and their outcomes. Capital categories include:

- Non-Discretionary: as defined above; not optional and cannot be eliminated or deferred.
- Shared Services: investments to sustain common support infrastructure.
- Discretionary/Asset Renewal: investments to enhance technology platforms and the pacing of asset replacements/refurbishments, including poles and stations.

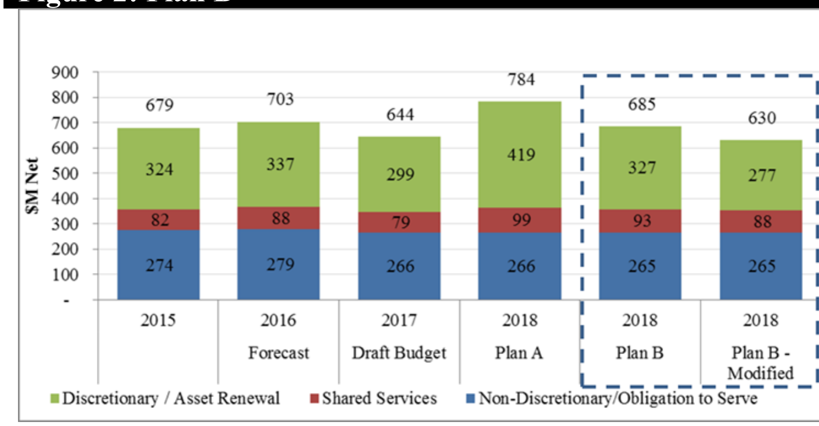
Figure 1: Plan A



Average annual spend (2019-2022): $798M

- Designed to meet business objectives
- Customer Service IT investments implemented
- 2018 Rate Increase **7.1%**
- Avg. annual rate increase **3.8%**
- Reliability: SAIDI improves by ~6%, SAIFI by 4%, by 2022*

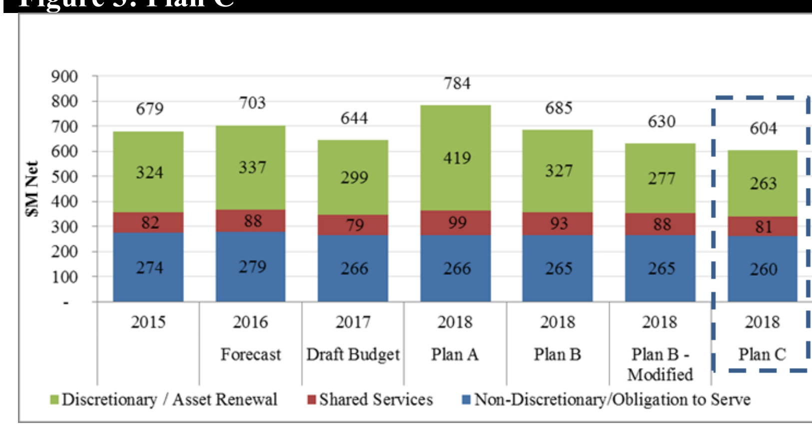
Figure 2: Plan B



Average annual spend (2019-2022): $798M $747M

- Business objectives largely achievable, but effect on reliability and related customer impacts may partly impair some objectives
- 2018 rate increase **6.2%**
- Avg. annual rate increase **3.5%**
- Lower reliability than Plan A
- Reliability: SAIDI improves by ~3%, SAIFI by 2%, by 2022*

Figure 3: Plan C



Average annual spend (2019-2022): $798M $747M $642M

- High risk of missing business objectives due to a large increase in reliability risk
- 2018 rate increase **5.1%**
- Avg. annual rate increase **2.9%**
- Reliability: SAIDI & SAIFI degrades ~2% by 2022*
- Decreased value for money as unplanned corrective work increases

* Reliability impacts modelled using relative investment impacts for vegetation management, pole replacement and distribution stations

F. KEY INVESTMENT IMPACTS

The customer engagement process, produced the following key findings that are more supportive of a lower rather than higher investment plan:

- *Keeping costs as low as possible is customers' top priority*. This preference is influenced by a desire to see HONI Dx demonstrate greater fiscal management and operational efficiency before considering rate increases. Many customers believe that total electricity costs are approaching being unaffordable.

- *Maintaining reliable electricity service is consistently second priority to cost*. Power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, is the primary concern. Some customers have capacity challenges and want more access to power in order to grow their enterprises. Customer service improvements are not something for which customers are willing to pay higher rates.

- *Large customers are more concerned with the reliability of service* they currently receive than residential and small business customers. However, although this group of customers is more inclined to value better reliability, they are not willing to entertain the corresponding rate impact.

- *All large customer segments prioritize the renewal program that focuses on replacing equipment that affects reliability* ahead of other options for improving reliability. Other options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages.

- *Willingness to accept a rate increase to maintain and improve service level is limited*. The majority of residential and small business customers are unwilling to accept higher rate impacts for better reliability; large customers generally accept that investments are needed; however they expect HONI Dx to exhaust all operational efficiencies before raising rates. At present, there is limited acceptance of any of the illustrative rate impact scenarios, even to maintain the current levels of reliability and service.

It is worth noting that when Residential & Small Business customers were informed that to maintain reliability and customer service, a typical customer's monthly bill would need to increase by about 1% ($2.00), about half of Residential and Seasonal customers were willing to accept it.

Customer feedback was incorporated into the planning process through the development of a number of key initiatives, including:

- A *restructured vegetation management plan* that will provide best in class vegetation management to circuits that distribute large volumes of power to support regional industries, large distribution customers and large quantities of Hydro One's residential customer base. A strategic maintenance program will provide a targeted, risk-based vegetation management treatment to circuits of lower criticality. This is expected to result in improved reliability without an increase in program spending.

- *Improvements to address industrial customer power quality* and reliability outliers.

- A *worst performing distribution line modernization initiative* which will deploy enhanced communication and automation capability to select distribution lines to improve reliability by reducing outage duration.

Hydro One is sensitive to the impact that its plans have on customer rates; in developing potential investment plans, Hydro One sought to strike a balance between three sometimes opposing factors: (i) the needs and preferences of its customers; (ii) the condition and reliability of the electrical system; and (iii) the effect on customer rates.

Reliability impacts and differences in capital spending for all scenarios were modelled using the effect of relative investment impacts for (i) vegetation management; (ii) pole replacement; and (iii) distribution stations. Although reliability can be affected by other factors, these three areas contribute the lion's share of reliability impacts and investment, and represent the most significant drivers of both customer rates and reliability. Understanding the impacts of each option on these key areas is important to understanding the relative trade-offs that must be made to affect rate impacts.

Following is a graphical analysis of the primary sources and impact of reliability on the Distribution system:

NB: SAIDI (duration) and SAIFI (frequency) impacts are calculated on a high level estimate basis, using simplified assumptions and are approximate.

Table: SAIDI Projection

Avg. 2013-15 SAIDI*:	**7.3 hours**	Average Number of Hours that a Customer is Interrupted				
	Assumptions			**Forecasted Impact[1]**		
	Failure Rate/Impact	**Contribution to SAIDI**	**SAIDI Contribution** (based on 2013-15)	**Plan A**	**Plan B**	**Plan C**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	20%	15%	(15)%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%
Estimated Impact to SAIDI				**6%**	**3%**	**(2)%**
Forecasted SAIDI (hours)				**6.9**	**7.1**	**7.4**

**-Excludes force majeure and loss of supply events*
1 – estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value

Table: SAIFI Projection

Avg. 2013-15 SAIFI*:	2.6 outages/year	Average Number of Times a Customer is Interrupted				
	Assumptions			**Forecasted Impact[2]**		
	Failure Rate/Impact	**Contribution to SAIFI**	**SAIFI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	20%	15%	(15)%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.6**

**-Excludes force majeure and loss of supply events*
2 – estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value

Vegetation management levels have not been materially adjusted in scenarios considered, except for minor changes in Plan C and no changes were made in all scenarios to investments in high priority rights of way. We consider vegetation management spending to be at appropriate levels and the strategy for 2016 onwards has been to maintain consistent spending and to drive tactical plans designed to over-achieve on units via productivity and take a more analytic approach to location of work in order to leverage reliability impacts. Reducing vegetation spend will result in deterioration in cycle that cannot be sustained, and it has a significant effect on reliability improvements.

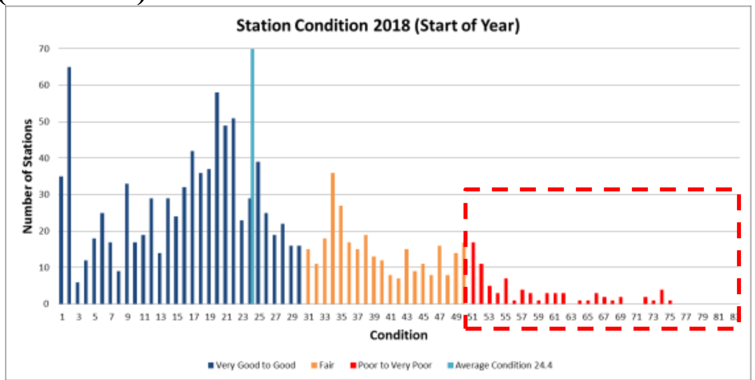
We currently maintain 112,000 km rights of way that generate approximately 15,530 outages per annum due to tree contact. These outages contribute 27% to SAIDI and 16% to SAIFI. All scenarios include consistent spending on high priority rights of way, with targets to eliminate the backlog of off-cycle rights of way by 2022 (9% decrease of SAIDI, 9% of SAIFI).

For Plans A and B, medium or low-priority rights of way maintenance is reduced by 1,000 km/yr, increasing backlog by 8-10%, increasing both SAIDI and SAIFI by 1%, but significantly offset by the 9% improvements in high priority rights of way. Plan C would take another 1,000km/yr out of the plan, increasing outages by 2% and reducing reliability by 5%.

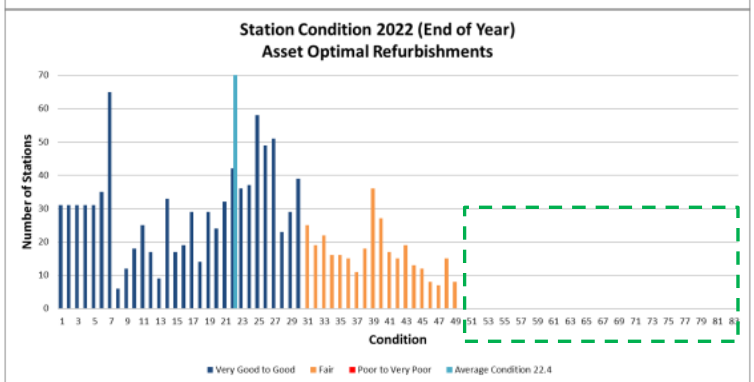
Distribution Stations: The leading contributor to outage frequency and second leading contributor to outage duration is defective equipment, which can be directly influenced by proactive asset replacements. The figures below show the projected impact of alternate replacement rates and the resulting "stations in poor condition surplus/deficit" at the end of the planning period. From Plans A through Plan C, the "backlog" of assets requiring replacement are identified through the growing red sections to the right of the individual graphs under the various plans/scenarios. Based on this, we can, and have, modelled the effects on reliability noted above.

Stations (Condition)

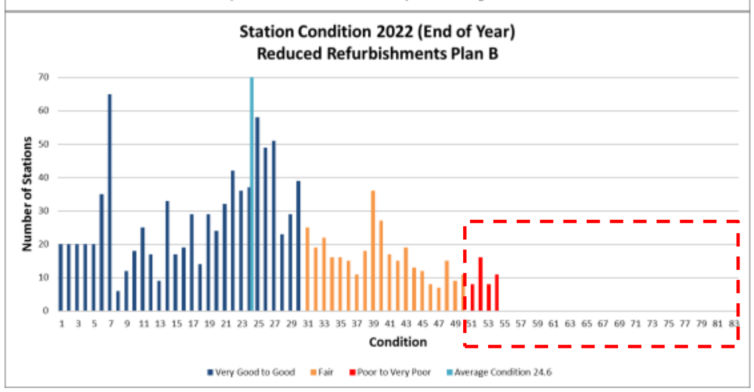
Current State



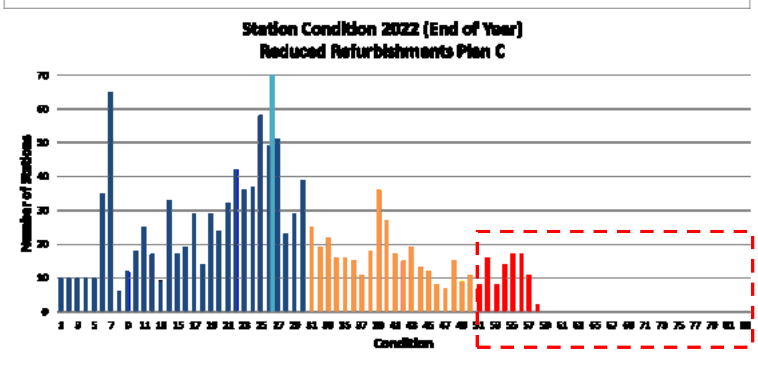
Plan A



Plan B



Plan C



We operate 1,005 stations, of which 70 are in poor condition. Currently, an average of 16 stations per year require an outage (23% of those in poor condition). A station outage, on average, affects 1,200 customers for 24 hours and contributes 4% to SAIDI and 3% to SAIFI. Because of the distributed nature of these stations, a failure has consequent impacts, for example failures often require redirecting a mobile station from a planned replacement underway and increasing our cost.

Also, a station failure will affect an entire community that has major impacts if they occur in cold conditions in Northern Ontario.

- Plan A: Replaces all stations deemed to be in poor condition (70) by the end of the horizon (2022). SAIDI and SAIFI improvement of ~14%.
- Plan B: Reduces the number of stations in poor condition to ~40 by the end of the horizon. SAIDI and SAIFI improvement of ~5%.
- Plan C: Increases the number of stations in poor condition to 90 by the end of the horizon. SAIDI and SAIFI degrade of ~4%.

Wood Poles: We manage a population of 1.6 million poles, of which 103,000 are in poor condition and need to be addressed. Failures average 345 outages annually, impacting an average of 185 customers for 10 hours, and contributes 3% to SAIDI and 2% to SAFI. In addition, as pole failures generally occur in the public domain (i.e. not in a Hydro One enclosed area), they also represent a public health and safety risk.

- Plan A: Reduces the number of poles in poor condition to 80,000 by the end of the planning horizon (2022). Reduces forced outages by ~20% or down to ~275 instances per year. Both SAIDI and SAIFI impacts from wood poles improve by 20%.
- Plan B: Reduces the number of poles in poor condition to 84,000 by the end of the horizon. Reduces forced outages by ~15% or down to ~290 instance per year, improving reliability impacts from wood poles by 15%.
- Plan C: Poles in poor condition will increase to 114,000 at the end of the horizon. Increases forced outages by 15% or up to ~395 instances per year, decreasing reliability due to wood poles by 15%.

G. OTHER ALTERNATIVES FOR RATE MITIGATION

Taking each of the above factors into account, and the outcomes of each plan in its entirety, there are some other options that can modify each of the plans as discussed below, and which have positive rate impacts but can only be withstood for limited durations (1 year) on the system. Of the options outlined below, we have included the first two measures in the "Plan B modified" scenario. The remainder were considered impractical to implement.

Potential Measure	**Potential 2018 Relief**	**Feasibility / Impacts**
Reduce 2018 Capital by up to $55 million	0.8% compared to Plan B	• Capital spending for 2018 reduced by $55 million, and then ramped back up to Plan B levels for the remaining 4 years • An assessment of in-service additions is underway to determine if there is any further ability to mitigate the 2018 rate increase. • The reduction of $55 million is subject to change, and we may be able to defer some of the spending or in service into 2019, increasing 2019 rates, but with a positive effect on 2018. To be finalized by December. • Can be accomplished without undue cost/unit impacts within the expected labour availability mix

		• Reduces IT spending by $5 million; to avoid reductions in customer investments, this must be sourced from cancellation of lower value projects or improved capital productivity • The wood pole program would be reduced by $25M or 3,100 poles in 2018. • Stations would be reduced by $4M (2 stations). • Component and Reinforcement activities would be reduced by $15M. Hydro One would have to carefully manage feeders with Large Customers to deliver the requested level of reliability communicated through the customer consultation feedback. • Facilities and Vehicle investments would be reduced by $6M combined.
OM&A - Corporate Common	0.25% compared to Plan B	• Reduce Corporate Common/Overhead budgets by executing on lower impact cost reductions and shared services efficiencies ($15million) • OM&A impact on distribution rates likely to be only 25% of total impact as a result of common cost allocation model - $3.5M impact • Represents an aggressive reduction to sustainable run rate levels of corporate common costs
Rate Smoothing	1-3%	• Places upwards pressure on future year rate increases. • Previous rate smoothing measures have been opposed by intervenors and not supported by the OEB, on the basis of intergenerational inequity, adds interest and carrying costs, masks the actual increase in any one year, and limited evidence that customers want to pay additional costs to achieve rate smoothing.
Reduce 2018 OM&A by upwards of $30M	Up to 2%	• Reduce total 2018 OM&A to 2015 levels (work program). • Total OM&A reduction over the planning period: $132M (2018-22), which would materially impact work programs and related reliability impacts. Not considered practical to achieve; our focus has been on efficiency, not reductions in work in order to achieve reliability improvements at the lowest cost possible.

H. **PRODUCTIVITY AND COST REDUCTION**

Guided by the new Executive Leadership Team, following work completed earlier this year, and building on existing initiatives, we have included efficiencies into work program costs. These are specific, material, and reflect our customers' reasonable desire to know that we have found all possible efficiencies before increasing their rates. Forecasted efficiencies were added to the plans <u>after</u> the optimisation process to ensure that those savings materialize and are not absorbed into additional units of work. Savings are realized in both the capital and OM&A work programs as follows:

$M	2018	2019	2020	2021	2022
Capital	**24.5**	**25.8**	**29.8**	**30.9**	**31.5**
OM&A	**32.1**	**37.3**	**38.8**	**40.3**	**43.1**
Total	**56.7**	**63.1**	**68.6**	**71.2**	**74.5**

The productivity and cost reductions totals shown above equate to an approximate 2% impact on Hydro One Distribution rates.

Significant productivity initiatives included in work programs include:

- *Move to Mobile($10M Capital, $3M OM&A):* To increase field workforce efficiencies through the utilization of new mobile application technology to manage inventory, document & field work order management and enable onsite decision making
- *Vegetation Management($10M OM&A):* To incorporate savings from various initiatives (e.g., use of hiring hall workers to complete low-skilled brush control activities)
- *Cable Locates ($8M OM&A):* Outsourcing extension
- *Procurement* To achieve cost reduction by bundling multiple contracts with a single supplier and negotiating volume discounts across multiple categories and contracts; maximize competitive pressure through multiple feedback rounds; installation of catalogue buying via new SAP tools and enforcement of compliance with procurement contracts
- *Standardization of Spend and Specifications:* To enable direct, like-for-like comparisons across bidders, reducing procurement costs and inventory requirements

Certain productivity initiatives are in process or have yielded savings and are included in OM&A efficiencies:

- *3rd Party Contractor Rate Reduction:* Rate reduced by 20-30% effective 2017
- *Backup and Storage Optimisation:* Reduce SAP storage costs by 75% without a material change in risk profile; Hydro One's monthly storage requirement decreased by 50%
- *Infrastructure and Database Decommissioning:* Decommissioned 138 serves and 38 databases that had very little or no utilization and reduced monthly server and database fees; plans for additional decommissioning in 2017

I. CUSTOMER BILL IMPACTS

The effects of investment plans on customer bills are very different depending on the class of customer. We have considered both the effect that our rate changes will have, and the estimated effect that other contributors to the bill may have based on recent industry activity and rate filings in process. This is the effect on the total bill, which for our R1 customers, could be as much as 6-7% on average over the five year term. In Plan B. our share of that increase, for distribution, is approximately $2.23 per month, or 1.2% over the 5-year period. The difference between Plan A and Plan C, for distribution, would be approximately $0.60 per month. Further details regarding the total bill impact, including Transmission, is reflected in the appendices.

Table: Plan B Customer Bill Impacts

Plan B	2017E	2018E	2019E	2020E	2021E	2022E	Avg
R1 Customer - 750 kWh							
Forecasted Total Bill ($)	**$165.11**	**$176.47**	**$187.07**	**$198.42**	**$210.15**	**$222.89**	**$199.00**
Total Bill Increase ($)		$11.36	$10.60	$11.35	$11.73	$12.73	$11.56
Total Bill Increase (%)		6.9%	6.0%	6.1%	5.9%	6.1%	6.2%
Bill Increase due to Other ($)		$7.55	$8.05	$8.57	$9.20	$9.80	$8.63
Bill Increase due to Hydro One Distribution ($)		$3.42	$2.02	$1.65	$1.91	$2.13	$2.23
Bill Increase due to Hydro One Distribution (%)		2.1%	1.1%	0.9%	1.0%	1.0%	1.2%
R2 Customer - 1200 kWh							
Forecasted Total Bill ($)	**$252.98**	**$270.58**	**$287.36**	**$305.47**	**$324.19**	**$344.52**	**$306.42**
Total Bill Increase ($)		$17.60	$16.78	$18.11	$18.72	$20.33	$18.31
Total Bill Increase (%)		7.0%	6.2%	6.3%	6.1%	6.3%	6.4%
Bill Increase due to Other ($)		$12.41	$13.24	$14.11	$15.16	$16.16	$14.22
Bill Increase due to Hydro One Distribution ($)		$4.57	$2.71	$2.22	$2.58	$2.88	$2.99
Bill Increase due to Hydro One Distribution (%)		1.8%	1.0%	0.8%	0.8%	0.9%	1.1%
First Nation's Customer - 1200 kWh							
Forecasted Total Bill ($)	**$221.66**	**$237.08**	**$251.78**	**$267.65**	**$284.05**	**$301.86**	**$268.48**
Total Bill Increase ($)		$15.42	$14.70	$15.87	$16.40	$17.81	$16.04
Total Bill Increase (%)		7.0%	6.2%	6.3%	6.1%	6.3%	6.4%
Bill Increase due to Other ($)		$10.87	$11.60	$12.37	$13.28	$14.16	$12.46
Bill Increase due to Hydro One Distribution ($)		$4.00	$2.37	$1.95	$2.26	$2.52	$2.62
Bill Increase due to Hydro One Distribution (%)		1.8%	1.0%	0.8%	0.8%	0.9%	1.1%
Large Commercial/Industrial 35000 kWh / 150 kW							
Forecasted Total Bill ($)	**$8,205.90**	**$8,749.97**	**$9,250.12**	**$9,784.95**	**$10,335.55**	**$10,933.48**	**$9,810.81**
Total Bill Increase ($)		$544.06	$500.15	$534.84	$550.60	$597.93	$545.51
Total Bill Increase (%)		6.6%	5.7%	5.8%	5.6%	5.8%	5.9%
Bill Increase due to Other ($)		$345.70	$368.14	$392.13	$420.57	$447.68	$394.84
Bill Increase due to Hydro One Distribution ($)		$178.13	$104.83	$85.44	$98.53	$109.39	$115.26
Bill Increase due to Hydro One Distribution (%)		2.2%	1.2%	0.9%	1.0%	1.1%	1.3%
Large Distribution Account - End User1450000 kWh / 3000 kW							
Forecasted Total Bill ($)	**$222,861.49**	**$238,077.91**	**$254,474.82**	**$273,137.29**	**$292,085.67**	**$312,737.59**	**$274,102.66**
Total Bill Increase ($)		$15,216.42	$16,396.91	$18,662.48	$18,948.38	$20,651.92	$17,975.22
Total Bill Increase (%)		6.8%	6.9%	7.3%	6.9%	7.1%	7.0%
Bill Increase due to Other ($)		$13,960.21	$14,994.81	$15,976.73	$17,314.79	$18,537.29	$16,156.77
Bill Increase due to Hydro One Distribution ($)		$414.91	$249.14	$207.18	$243.60	$275.79	$278.12
Bill Increase due to Hydro One Distribution (%)		0.2%	0.1%	0.1%	0.1%	0.1%	0.1%

J. FINANCIAL OUTCOMES

The financial forecasts related to the recommended investment plan will be presented to the Board in December. We have assessed the financial result of each of the scenarios, for earnings and cash flow impacts and balance sheet strength and flexibility. Financial viability and the effect of investment planning on shareholder outcomes must be considered in the process. Our conclusion is that the financial outcomes of all scenarios are not sufficiently different to weigh heavily in arriving at the optimum investment plan. For example, Earnings per Share between Plan A and Plan C vary by about 2%, and Debt to Rate Base is in a narrow band of 63-64% for all three scenarios. FFO/Debt improves for Plan A, due to lower capital expenditures, but is within "A" debt rating margins for all scenarios.

Capital expenditures over the five year period differ between scenario A and C by approximately $800 million. Although a significant amount in total, it is still a relatively small proportion of the total rate base and debt outstanding, and therefore has a relatively immaterial impact on the earnings and cash flow outcomes for shareholders.

We have therefore concluded that shareholders would be relatively indifferent between all scenarios currently being considered by management.

K. EARNINGS SHARING MECHANISM

The table below illustrates how an earning sharing mechanism would work with a 100 basis point threshold. To illustrate potential returns to customers, the table assumes certain levels of "overearnings" in each year, that are above the estimated "Plan A" ROE.

As outlined, in 2019 approximately $30 million in additional net income is the point at which the ESM begins to return monies to customers. This level of incremental net income, considering potential weather and cost savings impacts, is not out of the question, and as such we consider the current construct we are considering of a 50/50 sharing of savings over 100bps in excess of ROE to be reasonable.

We have considered whether it makes sense to increase the extent of the earnings sharing, and have concluded that there is limited benefit. First, the current structure, including the 100 bps threshold, is familiar to and has been previously accepted by the OEB. Secondly, the OEB generally views ESM to be a mechanism that, consistent with the RRFE framework, aligns the interests of customers with those of the utility. It is important to understand that any amounts to be shared with customers pursuant to the ESM will only reduce future rates beginning in 2023, in the next rate setting period. However, the OEB is unlikely to view a more "generous" ESM to be an appropriate offset to unfavourable rate increases. Instead, Hydro One remains focused on productivity and cost efficiencies to help keep rates down.

Management is still considering available options for including an ESM in the Distribution application next year.

Draft Earnings Sharing Calculation
Hydro One Networks Inc - Distribution

	2018	2019	2020	2021	2022	
Deemed Approval from OEB						
Estimated Distribution Rate Base	$ 7,741	$ 8,207	$ 8,683	$ 9,290	$ 9,709	
Deemed Equity (%)	40%	40%	40%	40%	40%	
Deemed Equity ($)	$ 3,097	$ 3,283	$ 3,473	$ 3,716	$ 3,883	A
Allowed return on equity (%)	8.77%	8.77%	8.77%	8.77%	8.77%	B
Allowed return on equity ($)	$ 272	$ 288	$ 305	$ 326	$ 341	C = A x B
Earnings Sharing Analysis						
Revenues						
Filed OM&A in revenue requirement	$ 587	$ 596	$ 605	$ 614	$ 623	D
Costs						
Forecast OM&A in costs	$ 587	$ 587	$ 587	$ 587	$ 587	E
Additional Savings		$ (30)	$ (33)	$ (36)	$ (40)	F
Earnings before tax	$ -	$ 39	$ 51	$ 63	$ 76	G = D - E - F
Earnings after tax	$ -	$ 32	$ 41	$ 52	$ 62	H
Forecasted return on equity ($)	$ 272	$ 320	$ 346	$ 377	$ 403	I = C + H
Forecasted return on equity (%)	8.77%	9.74%	9.96%	10.16%	10.37%	J = I / A
Allowed return on equity (%)	8.77%	8.77%	8.77%	8.77%	8.77%	B
Change from Allowed ROE	**0.00%**	**0.97%**	**1.19%**	**1.39%**	**1.60%**	K = J - B
Earnings Sharing Threshold	1.00%	1.00%	1.00%	1.00%	1.00%	L
Earnings in excess of threshold (%)	0.00%	0.00%	0.19%	0.39%	0.60%	M = L - K
Applicable earnings in excess of threshold ($)	$ -	$ -	$ 7	$ 14	$ 23	N = A x M
Amount to be shared (%)	50%	50%	50%	50%	50%	
Refund to rate payers in 2023 ($)	**$ -**	**$ -**	**$ 3**	**$ 7**	**$ 12**	

SUMMARY OF EXPENDITURES & IMPACTS

For information, following is a summary of top line outcomes related to the three principal scenarios outlined in this memorandum. To reduce complexity, we have not included the Plan B – Modified scenario.

In conclusion, we believe that we have a path to achieving an optimal plan that will balance the expressed needs and preferences of our customers, system reliability and customer rate impacts. We should also be able to minimise the effect of our plan on the 2018 rates, and still maintain either consistent or slightly improved reliability. We look forward to discussing our final plan with the Board of Directors in December.

Plan A	2017	2018	2019	2020	2021	2022	Avg
Capex ($M Net)	$ 644	$ 784	$ 819	$ 750	$ 760	$ 864	$ 770
OM&A ($M)	$593	$587	$596	$605	$614	$623	$603
Reliability (SAIDI) vs. 2013-15 average						6%↑	
Distribution Rate Increase		7.1%	3.4%	2.5%	3.0%	2.8%	3.8%
Total Bill R1 Customer ($/month)	$165.11	$176.99	$187.91	$199.62	$211.88	$225.02	$200.29

Plan B	2017	2018	2019	2020	2021	2022	Avg
Capex ($M Net)	$ 644	$ 685	$ 742	$ 713	$ 721	$ 812	$ 720
OM&A ($M)	$593	$587	$596	$605	$614	$623	$603
Reliability (SAIDI) vs. 2013-15 average						3%↑	
Distribution Rate Increase		6.2%	3.3%	2.5%	2.7%	2.8%	3.5%
Total Bill R1 Customer ($/month)	$165.11	$176.47	$187.07	$198.42	$210.15	$222.89	$199.00

Plan C	2017	2018	2019	2020	2021	2022	Avg
Capex ($M Net)	$ 644	$ 604	$ 644	$ 606	$ 613	$ 706	$ 636
OM&A ($M)	$593	$587	$596	$605	$614	$623	$603
Reliability (SAIDI) vs. 2013-15 average						2%↓	
Distribution Rate Increase		5.0%	2.9%	1.9%	2.2%	2.3%	2.9%
Total Bill R1 Customer ($/month)	$165.11	$175.81	$186.16	$197.13	$208.52	$220.90	$197.70

APPENDIX – R1 CUSTOMER BILL IMPACTS

R1 Customer - 750 kWh	2017E	2018E	2019E	2020E	2021E	2022E	Avg
PLAN A							
Forecasted Total Monthly Bill ($)	$165.11	$176.99	$187.91	$199.62	$211.88	$225.02	$200.29
Total Bill Increase ($)		$11.89	$10.92	$11.71	$12.26	$13.13	$11.98
Total Bill Increase (%)		7.2%	6.2%	6.2%	6.1%	6.2%	6.4%
Bill Increase - non Hydro One ($)		$7.58	$8.29	$8.92	$9.49	$10.16	$8.89
Bill Increase - non Hydro One (%)		4.6%	4.7%	4.7%	4.8%	4.8%	4.7%
Bill Increase due to Hydro One ($)		$4.31	$2.63	$2.80	$2.77	$2.97	$3.10
Bill Increase due to Hydro One (%)		2.6%	1.5%	1.5%	1.4%	1.4%	2%
Bill Increase due to Hydro One Distribution ($)		$3.91	$2.10	$1.67	$2.15	$2.16	$2.40
Bill Increase due to Hydro One Distribution (%)		2.4%	1.2%	0.9%	1.1%	1.0%	1.3%
PLAN B							
Forecasted Total Monthly Bill ($)	$165.11	$176.47	$187.07	$198.42	$210.15	$222.89	$199.00
Total Bill Increase ($)		$11.36	$10.60	$11.35	$11.73	$12.73	$11.56
Total Bill Increase (%)		6.9%	6.0%	6.1%	5.9%	6.1%	6.2%
Bill Increase - non Hydro One ($)		$7.55	$8.05	$8.57	$9.20	$9.80	$8.63
Bill Increase - non Hydro One (%)		4.6%	4.6%	4.6%	4.6%	4.7%	4.6%
Bill Increase due to Hydro One ($)		$3.81	$2.55	$2.78	$2.53	$2.94	$2.92
Bill Increase due to Hydro One (%)		2.3%	1.4%	1.5%	1.3%	1.4%	2%
Bill Increase due to Hydro One Distribution ($)		$3.42	$2.02	$1.65	$1.91	$2.13	$2.23
Bill Increase due to Hydro One Distribution (%)		2.1%	1.1%	0.9%	1.0%	1.0%	1.2%
PLAN C							
Forecasted Total Monthly Bill ($)	$165.11	$175.81	$186.16	$197.13	$208.52	$220.90	$197.70
Total Bill Increase ($)		$10.70	$10.34	$10.97	$11.39	$12.38	$11.16
Total Bill Increase (%)		6.5%	5.9%	5.9%	5.8%	5.9%	6.0%
Bill Increase - non Hydro One ($)		$7.55	$8.06	$8.61	$9.24	$9.86	$8.66
Bill Increase - non Hydro One (%)		4.6%	4.6%	4.6%	4.7%	4.7%	4.6%
Bill Increase due to Hydro One ($)		$3.15	$2.29	$2.36	$2.15	$2.51	$2.49
Bill Increase due to Hydro One (%)		1.9%	1.3%	1.3%	1.1%	1.2%	1%
Bill Increase due to Hydro One Distribution ($)		$2.76	$1.75	$1.24	$1.53	$1.71	$1.80
Bill Increase due to Hydro One Distribution (%)		1.7%	1.0%	0.7%	0.8%	0.8%	1.0%

APPENDIX – R2 CUSTOMER BILL IMPACTS

R2 Customer - 1200 kWh	2017E	2018E	2019E	2020E	2021E	2022E	Avg
PLAN A							
Forecasted Total Monthly Bill ($)	**$252.98**	**$271.24**	**$288.12**	**$306.25**	**$325.25**	**$345.60**	**$307.29**
Total Bill Increase ($)		$18.26	$16.88	$18.13	$18.99	$20.36	**$18.52**
Total Bill Increase (%)		7.2%	6.2%	6.3%	6.2%	6.3%	**6.4%**
Bill Increase - non Hydro One ($)		$12.41	$13.23	$14.11	$15.12	$16.16	**$14.21**
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	4.9%	5.0%	**4.9%**
Bill Increase due to Hydro One ($)		**$5.85**	**$3.65**	**$4.02**	**$3.87**	**$4.20**	**$4.32**
Bill Increase due to Hydro One (%)		2.3%	1.3%	1.4%	1.3%	1.3%	**2%**
Bill Increase due to Hydro One Distribution ($)		**$5.23**	**$2.81**	**$2.24**	**$2.89**	**$2.91**	**$3.22**
Bill Increase due to Hydro One Distribution (%)		2.1%	1.0%	0.8%	0.9%	0.9%	**1.1%**
PLAN B							
Forecasted Total Monthly Bill ($)	**$252.98**	**$270.58**	**$287.36**	**$305.47**	**$324.19**	**$344.52**	**$306.42**
Total Bill Increase ($)		$17.60	$16.78	$18.11	$18.72	$20.33	**$18.31**
Total Bill Increase (%)		7.0%	6.2%	6.3%	6.1%	6.3%	**6.4%**
Bill Increase - non Hydro One ($)		$12.41	$13.24	$14.11	$15.16	$16.16	**$14.22**
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	5.0%	5.0%	**4.9%**
Bill Increase due to Hydro One ($)		**$5.19**	**$3.54**	**$4.00**	**$3.56**	**$4.16**	**$4.09**
Bill Increase due to Hydro One (%)		2.1%	1.3%	1.4%	1.2%	1.3%	**1%**
Bill Increase due to Hydro One Distribution ($)		**$4.57**	**$2.71**	**$2.22**	**$2.58**	**$2.88**	**$2.99**
Bill Increase due to Hydro One Distribution (%)		1.8%	1.0%	0.8%	0.8%	0.9%	**1.1%**
PLAN C							
Forecasted Total Monthly Bill ($)	**$252.98**	**$269.69**	**$286.14**	**$303.74**	**$322.01**	**$341.86**	**$304.69**
Total Bill Increase ($)		$16.71	$16.44	$17.60	$18.27	$19.85	**$17.77**
Total Bill Increase (%)		6.6%	6.1%	6.2%	6.0%	6.2%	**6.2%**
Bill Increase - non Hydro One ($)		$12.41	$13.25	$14.16	$15.23	$16.26	**$14.26**
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	5.0%	5.0%	**5.0%**
Bill Increase due to Hydro One ($)		**$4.30**	**$3.19**	**$3.44**	**$3.04**	**$3.59**	**$3.51**
Bill Increase due to Hydro One (%)		1.7%	1.2%	1.2%	1.0%	1.1%	**1%**
Bill Increase due to Hydro One Distribution ($)		**$3.68**	**$2.35**	**$1.66**	**$2.06**	**$2.31**	**$2.41**
Bill Increase due to Hydro One Distribution (%)		1.5%	0.9%	0.6%	0.7%	0.7%	**0.9%**

APPENDIX – FIRST NATIONS CUSTOMER BILL IMPACTS

First Nation's Customer - 1200 kWh	2017E	2018E	2019E	2020E	2021E	2022E	Avg
PLAN A							
Forecasted Total Monthly Bill ($)	$221.66	$237.66	$252.45	$268.34	$284.98	$302.81	$269.25
Total Bill Increase ($)		$16.00	$14.79	$15.88	$16.64	$17.83	$16.23
Total Bill Increase (%)		7.2%	6.2%	6.3%	6.2%	6.3%	6.4%
Bill Increase - non Hydro One ($)		$10.87	$11.59	$12.36	$13.25	$14.16	$12.45
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	4.9%	5.0%	4.9%
Bill Increase due to Hydro One ($)		$5.13	$3.20	$3.52	$3.39	$3.68	$3.78
Bill Increase due to Hydro One (%)		2.3%	1.3%	1.4%	1.3%	1.3%	2%
Bill Increase due to Hydro One Distribution ($)		$4.58	$2.46	$1.96	$2.53	$2.55	$2.82
Bill Increase due to Hydro One Distribution (%)		2.1%	1.0%	0.8%	0.9%	0.9%	1.1%
PLAN B							
Forecasted Total Monthly Bill ($)	$221.66	$237.08	$251.78	$267.65	$284.05	$301.86	$268.48
Total Bill Increase ($)		$15.42	$14.70	$15.87	$16.40	$17.81	$16.04
Total Bill Increase (%)		7.0%	6.2%	6.3%	6.1%	6.3%	6.4%
Bill Increase - non Hydro One ($)		$10.87	$11.60	$12.37	$13.28	$14.16	$12.46
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	5.0%	5.0%	4.9%
Bill Increase due to Hydro One ($)		$4.55	$3.11	$3.50	$3.12	$3.65	$3.58
Bill Increase due to Hydro One (%)		2.1%	1.3%	1.4%	1.2%	1.3%	1%
Bill Increase due to Hydro One Distribution ($)		$4.00	$2.37	$1.95	$2.26	$2.52	$2.62
Bill Increase due to Hydro One Distribution (%)		1.8%	1.0%	0.8%	0.8%	0.9%	1.1%
PLAN C							
Forecasted Total Monthly Bill ($)	$221.66	$236.30	$250.71	$266.13	$282.14	$299.53	$266.96
Total Bill Increase ($)		$14.64	$14.41	$15.42	$16.01	$17.39	$15.57
Total Bill Increase (%)		6.6%	6.1%	6.2%	6.0%	6.2%	6.2%
Bill Increase - non Hydro One ($)		$10.87	$11.61	$12.41	$13.34	$14.24	$12.49
Bill Increase - non Hydro One (%)		4.9%	4.9%	4.9%	5.0%	5.0%	5.0%
Bill Increase due to Hydro One ($)		$3.77	$2.80	$3.01	$2.67	$3.15	$3.08
Bill Increase due to Hydro One (%)		1.7%	1.2%	1.2%	1.0%	1.1%	1%
Bill Increase due to Hydro One Distribution ($)		$3.23	$2.06	$1.46	$1.80	$2.02	$2.11
Bill Increase due to Hydro One Distribution (%)		1.5%	0.9%	0.6%	0.7%	0.7%	0.9%

APPENDIX – LARGE COMMERCIAL/INDUSTRIAL CUSTOMER BILL IMPACTS

Large Commercial/Industrial 35000 kWh / 150 kW	2017E	2018E	2019E	2020E	2021E	2022E	Avg
PLAN A							
Forecasted Total Monthly Bill ($)	$8,205.90	$8,775.82	$9,279.91	$9,815.49	$10,376.69	$10,975.77	$9,844.73
Total Bill Increase ($)		$569.92	$504.08	$535.58	$561.20	$599.08	$553.97
Total Bill Increase (%)		6.9%	5.7%	5.8%	5.7%	5.8%	6.0%
Bill Increase - non Hydro One ($)		$345.70	$368.00	$392.11	$419.25	$447.58	$394.53
Bill Increase - non Hydro One (%)		4.2%	4.2%	4.2%	4.3%	4.3%	4.2%
Bill Increase due to Hydro One ($)		$224.22	$136.09	$143.47	$141.95	$151.50	$159.45
Bill Increase due to Hydro One (%)		2.7%	1.6%	1.5%	1.4%	1.5%	2%
Bill Increase due to Hydro One Distribution ($)		$203.99	$108.91	$86.22	$110.47	$110.67	$124.05
Bill Increase due to Hydro One Distribution (%)		2.5%	1.2%	0.9%	1.1%	1.1%	1.4%
PLAN B							
Forecasted Total Monthly Bill ($)	$8,205.90	$8,749.97	$9,250.12	$9,784.95	$10,335.55	$10,933.48	$9,810.81
Total Bill Increase ($)		$544.06	$500.15	$534.84	$550.60	$597.93	$545.51
Total Bill Increase (%)		6.6%	5.7%	5.8%	5.6%	5.8%	5.9%
Bill Increase - non Hydro One ($)		$345.70	$368.14	$392.13	$420.57	$447.68	$394.84
Bill Increase - non Hydro One (%)		4.2%	4.2%	4.2%	4.3%	4.3%	4.3%
Bill Increase due to Hydro One ($)		$198.36	$132.01	$142.70	$130.03	$150.25	$150.67
Bill Increase due to Hydro One (%)		2.4%	1.5%	1.5%	1.3%	1.5%	2%
Bill Increase due to Hydro One Distribution ($)		$178.13	$104.83	$85.44	$98.53	$109.39	$115.26
Bill Increase due to Hydro One Distribution (%)		2.2%	1.2%	0.9%	1.0%	1.1%	1.3%
PLAN C							
Forecasted Total Monthly Bill ($)	$8,205.90	$8,715.49	$9,202.44	$9,717.45	$10,250.41	$10,829.79	$9,743.12
Total Bill Increase ($)		$509.59	$486.95	$515.02	$532.96	$579.38	$524.78
Total Bill Increase (%)		6.2%	5.6%	5.6%	5.5%	5.7%	5.7%
Bill Increase - non Hydro One ($)		$345.70	$368.66	$393.75	$422.75	$450.78	$396.33
Bill Increase - non Hydro One (%)		4.2%	4.2%	4.3%	4.4%	4.4%	4.3%
Bill Increase due to Hydro One ($)		$163.89	$118.28	$121.27	$110.20	$128.60	$128.45
Bill Increase due to Hydro One (%)		2.0%	1.4%	1.3%	1.1%	1.3%	1%
Bill Increase due to Hydro One Distribution ($)		$143.65	$91.10	$63.98	$78.68	$87.68	$93.02
Bill Increase due to Hydro One Distribution (%)		1.8%	1.0%	0.7%	0.8%	0.9%	1.0%

APPENDIX – LARGE DISTRIBUTION ACCOUNT CUSTOMER BILL IMPACTS

Large Distribution Account - End User 1450000 kWh / 3000 kW	2017E	2018E	2019E	2020E	2021E	2022E	Avg
PLAN A							
Forecasted Total Monthly Bill ($)	**$222,861.49**	**$238,138.14**	**$254,544.20**	**$273,208.41**	**$292,181.50**	**$312,836.10**	**$274,181.67**
Total Bill Increase ($)		$15,276.64	$16,406.06	$18,664.21	$18,973.09	$20,654.60	**$17,994.92**
Total Bill Increase (%)		6.9%	6.9%	7.3%	6.9%	7.1%	**7.0%**
Bill Increase - non Hydro One ($)		$13,960.21	$14,994.26	$15,976.60	$17,309.96	$18,536.74	**$16,155.56**
Bill Increase - non Hydro One (%)		6.3%	6.3%	6.3%	6.3%	6.3%	**6.3%**
Bill Increase due to Hydro One ($)		**$1,316.43**	**$1,411.80**	**$2,687.61**	**$1,663.12**	**$2,117.86**	**$1,839.37**
Bill Increase due to Hydro One (%)		0.6%	0.6%	1.1%	0.6%	0.7%	**1%**
Bill Increase due to Hydro One Distribution ($)		**$475.14**	**$258.86**	**$209.13**	**$273.21**	**$279.18**	**$299.10**
Bill Increase due to Hydro One Distribution (%)		0.2%	0.1%	0.1%	0.1%	0.1%	**0.1%**

PLAN B							
Forecasted Total Monthly Bill ($)	**$222,861.49**	**$238,077.91**	**$254,474.82**	**$273,137.29**	**$292,085.67**	**$312,737.59**	**$274,102.66**
Total Bill Increase ($)		$15,216.42	$16,396.91	$18,662.48	$18,948.38	$20,651.92	**$17,975.22**
Total Bill Increase (%)		6.8%	6.9%	7.3%	6.9%	7.1%	**7.0%**
Bill Increase - non Hydro One ($)		$13,960.21	$14,994.81	$15,976.73	$17,314.79	$18,537.29	**$16,156.77**
Bill Increase - non Hydro One (%)		6.3%	6.3%	6.3%	6.3%	6.3%	**6.3%**
Bill Increase due to Hydro One ($)		**$1,256.20**	**$1,402.10**	**$2,685.75**	**$1,633.59**	**$2,114.64**	**$1,818.45**
Bill Increase due to Hydro One (%)		0.6%	0.6%	1.1%	0.6%	0.7%	**1%**
Bill Increase due to Hydro One Distribution ($)		**$414.91**	**$249.14**	**$207.18**	**$243.60**	**$275.79**	**$278.12**
Bill Increase due to Hydro One Distribution (%)		0.2%	0.1%	0.1%	0.1%	0.1%	**0.1%**

PLAN C							
Forecasted Total Monthly Bill ($)	**$222,861.49**	**$237,997.60**	**$254,363.76**	**$272,980.07**	**$291,887.37**	**$312,496.08**	**$273,944.98**
Total Bill Increase ($)		$15,136.11	$16,366.15	$18,616.32	$18,907.29	$20,608.72	**$17,926.92**
Total Bill Increase (%)		6.8%	6.9%	7.3%	6.9%	7.1%	**7.0%**
Bill Increase - non Hydro One ($)		$13,960.21	$14,996.70	$15,982.53	$17,322.78	$18,548.76	**$16,162.20**
Bill Increase - non Hydro One (%)		6.3%	6.3%	6.3%	6.3%	6.4%	**6.3%**
Bill Increase due to Hydro One ($)		**$1,175.90**	**$1,369.45**	**$2,633.79**	**$1,584.51**	**$2,059.96**	**$1,764.72**
Bill Increase due to Hydro One (%)		0.5%	0.6%	1.0%	0.6%	0.7%	**1%**
Bill Increase due to Hydro One Distribution ($)		**$334.60**	**$216.47**	**$155.08**	**$194.36**	**$220.77**	**$224.26**
Bill Increase due to Hydro One Distribution (%)		0.2%	0.1%	0.1%	0.1%	0.1%	**0.1%**

Glossary

Vegetation Management  *Wallace Tap	Hydro one has an active demand vegetation management program that addresses emergent and urgent safety/reliability risks identified by our customers and through internal asset inspections. Hydro One performs tree clearing and brushing on its 112,000 km of distribution rights of way. As per the last OEB rate filing, all M-Class feeders need to be cleared every 8 years, 94% of our Transmission feeders (M-Class) are less than 8 years since the last vegetation management treatment. From 2013-2015 tree contacts accounted for 16% of the System Average Interruption Frequency Index and 27% of the System Average Interruption Duration Index.
Wood Pole Replacement 	The main purpose of the pole replacement program is to prevent failures from happening. Pole failures can lead to long power interruptions for our customers and can cause a potential public safety hazard. Hydro One owns 1.6 Million distribution poles, and there are an additional 350,000 poles supported by our joint use partner owned poles. These poles support approximately 120,000 km of distribution lines and equipment. The current average age of a pole is 39 years old on the Hydro One network.
Distribution Station Refurbishment  *Cobden DS	Hydro One has 1005 Distribution Stations. Distribution Stations are comprised of transformers, breakers, structures, reclosers, switches, fuses, fences, grounding, yards and access roads. When multiple assets at a DS are in need of replacement they are bundled into station refurbishment projects. In 2015, 28 distribution station refurbishments were completed and started to include elements of grid modernization.

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: November 11, 2016

Re: Financial Forecasts

Hydro One has prepared a number of different alternatives relative to its Distribution rate filing. The final financial forecasts related to the investment plan will be presented to the Board in December. As information, attached are analyses that supported the conclusion that financial outcomes are not sufficiently material to weigh heavily in selecting the investment plan for the Company. For example, Earnings per Share between Plan A and Plan C vary by about 2%, and Debt to Rate Base is in a narrow band of 63-64% for all three scenarios.

Capital expenditures in absolute terms differ significantly between scenarios, with a difference in the five year period between scenario A and C of approximately $800 million. Although a significant amount, it is a relatively small proportion of the total rate base and total debt outstanding, and therefore has a relatively immaterial impact on the outcome.

We have therefore concluded that shareholders would be relatively indifferent between all scenarios currently being considered by management.

Hydro One Ltd. Plan A	2018E	2019E	2020E	2021E	2022E	2018-22 CAGR
Net income	$ 716	$ 776	$ 820	$ 865	$ 913	5.0%
Earnings per share	$ 1.20	$ 1.30	$ 1.38	$ 1.45	$ 1.54	
ROE, Before "equity bump"	9.9%	10.4%	10.6%	10.8%	11.0%	
Funds from Operations	$ 1,659	$ 1,781	$ 1,845	$ 1,940	$ 2,033	
FFO / Debt	13.2%	13.4%	13.1%	13.0%	12.8%	
Capital Expenditures	$ 1,847	$ 2,050	$ 2,061	$ 2,257	$ 2,351	
In-service Additions	$ 2,058	$ 1,893	$ 2,146	$ 1,999	$ 2,496	
Rate Base	$19,800	$21,005	$22,187	$23,391	$24,727	4.5%
Total Debt to Rate Base	63.2%	63.4%	63.5%	64.0%	64.4%	
Distribution Tariff rate increase	7.1%	3.4%	2.5%	3.0%	2.8%	
Distribution Bill Impact (R1 customer)	2.4%	1.2%	0.9%	1.1%	1.0%	

Plan B						
Net income	$ 714	$ 773	$ 816	$ 861	$ 908	4.9%
Earnings per share	$ 1.20	$ 1.30	$ 1.37	$ 1.45	$ 1.53	
ROE, Before "equity bump"	9.9%	10.3%	10.5%	10.7%	10.9%	
Funds from Operations	$ 1,655	$ 1,775	$ 1,836	$ 1,929	$ 2,022	
FFO / Debt	13.3%	13.5%	13.2%	13.1%	12.9%	
Capital Expenditures	$ 1,743	$ 1,969	$ 2,019	$ 2,213	$ 2,295	
In-service Additions	$ 1,971	$ 1,822	$ 2,103	$ 1,964	$ 2,435	
Rate Base	$19,758	$20,884	$22,014	$23,184	$24,479	4.4%
Total Debt to Rate Base	62.9%	62.9%	63.1%	63.6%	63.8%	
Distribution Tariff rate increase	6.2%	3.3%	2.5%	2.7%	2.8%	
Distribution Bill Impact (R1 customer)	2.1%	1.1%	0.9%	1.0%	1.0%	

Plan C						
Net income	$ 712	$ 767	$ 808	$ 852	$ 897	4.7%
Earnings per share	$ 1.20	$ 1.29	$ 1.36	$ 1.43	$ 1.51	
ROE, Before "equity bump"	9.8%	10.3%	10.5%	10.6%	10.8%	
Funds from Operations	$ 1,648	$ 1,763	$ 1,819	$ 1,908	$ 1,995	
FFO / Debt	13.3%	13.6%	13.4%	13.3%	13.1%	
Capital Expenditures	$ 1,656	$ 1,865	$ 1,904	$ 2,099	$ 2,183	
In-service Additions	$ 1,891	$ 1,697	$ 1,988	$ 1,850	$ 2,318	
Rate Base	$19,720	$20,744	$21,761	$22,828	$24,020	4.0%
Total Debt to Rate Base	62.6%	62.5%	62.6%	63.0%	63.2%	
Distribution Tariff rate increase	5.0%	2.9%	1.9%	2.2%	2.3%	
Distribution Bill Impact (R1 customer)	1.7%	1.0%	0.7%	0.8%	0.8%	

EARNINGS SHARING MECHANISM – Illustrative Example

The table below illustrates how an earning sharing mechanism would work with a 100 basis point threshold. To illustrate potential returns to customers, the table assumes certain levels of "overearnings" in each year, that are above the estimated "Plan A" ROE.

As outlined, in 2019 approximately $33 million in additional net income is the point at which the ESM begins to return monies to customers. This level of incremental net income, considering potential weather and cost savings impacts, is not out of the question, and as such we consider the current construct we are considering of a 50/50 sharing of savings over 100bps in excess of ROE to be reasonable.

We have considered whether it makes sense to increase the extent of the earnings sharing, and have concluded that there is limited benefit. First, the current structure, including the 100 bps threshold, is familiar to and has been previously accepted by the OEB. Second, the OEB generally views ESM to be a mechanism that, consistent with the RRFE framework, aligns the interests of customers with those of the utility. It is important to understand that amounts to be shared with customers pursuant to the ESM will reduce future rates beginning in 2023. However, the OEB is unlikely to view a more "generous" ESM to be an appropriate offset to unfavourable rate increases. Instead, Hydro One remains focused on productivity and cost efficiencies to help keep rates down.

Management is still considering available options for including an ESM in the Distribution application next year.

Draft Earnings Sharing Calculation
Hydro One Networks Inc - Distribution

	2018	2019	2020	2021	2022	
Deemed Approval from OEB						
Estimated Distribution Rate Base	$ 7,741	$ 8,207	$ 8,683	$ 9,290	$ 9,709	
Deemed Equity (%)	40%	40%	40%	40%	40%	
Deemed Equity ($)	$ 3,097	$ 3,283	$ 3,473	$ 3,716	$ 3,883	A
Allowed return on equity (%)	8.77%	8.77%	8.77%	8.77%	8.77%	B
Allowed return on equity ($)	$ 272	$ 288	$ 305	$ 326	$ 341	C = A x B
Earnings Sharing Analysis						
Revenues						
Filed OM&A in revenue requirement	$ 587	$ 596	$ 605	$ 614	$ 623	D
Costs						
Forecast OM&A in costs	$ 587	$ 587	$ 587	$ 587	$ 587	E
Additional Savings		$ (30)	$ (33)	$ (36)	$ (40)	F
Earnings before tax	$ -	$ 39	$ 51	$ 63	$ 76	G = D - E - F
Earnings after tax	$ -	$ 32	$ 41	$ 52	$ 62	H
Forecasted return on equity ($)	$ 272	$ 320	$ 346	$ 377	$ 403	I = C + H
Forecasted return on equity (%)	8.77%	9.74%	9.96%	10.16%	10.37%	J = I / A
Allowed return on equity (%)	8.77%	8.77%	8.77%	8.77%	8.77%	B
Change from Allowed ROE	**0.00%**	**0.97%**	**1.19%**	**1.39%**	**1.60%**	K = J - B
Earnings Sharing Threshold	1.00%	1.00%	1.00%	1.00%	1.00%	L
Earnings in excess of threshold (%)	0.00%	0.00%	0.19%	0.39%	0.60%	M = L - K
Applicable earnings in excess of threshold ($)	$ -	$ -	$ 7	$ 14	$ 23	N = A x M
Amount to be shared (%)	50%	50%	50%	50%	50%	
Refund to rate payers in 2023 ($)	**$ -**	**$ -**	**$ 3**	**$ 7**	**$ 12**	

Hydro One Limited/ Hydro One Inc.

Submission to the Board of Directors

Date: February 10, 2017

Re: Distribution Filing

On March 31, 2017, Hydro One Networks Distribution plans to file an application with the Ontario Energy Board ("OEB") seeking the OEB's approval of a Custom Incentive Rate regime for 2018 to 2022 Distribution Rates. The attached submission, for information, sets out the form of the Distribution application, and outlines its key components.

As context, we are aware that the planned Application will be filed when there are a number of discussions occurring at a policy level between the Government of Ontario and members of the Ontario electricity industry. These discussions relate to the potential mitigation of customer bills. This discussion is far reaching, and includes reducing the amount of the Global Adjustment that is recovered in the electricity commodity prices administered by the Ontario Energy Board, and also discussions relating to delivery rates.

Hydro One does not expect these discussions to have a material effect on the derivation of Hydro One Distribution's revenue requirement and the proposed Custom Incentive Rate regime is designed to flexibly accommodate potential changes to cost allocation and rate design that would drive delivery rate mitigation for certain rate classes.

The customer rate impacts presented in this submission and prior Board submissions represent the continuation of the status quo. Should delivery rate and commodity price relief be implemented by the Government, estimated rate impacts emanating from the planned Application would likely increase, both as a percentage change in delivery rate and on a total bill basis. There would also be public notice by the OEB of our request for rate increases at the same time that the Province is announcing price decreases, which we may need to address in media communications.

Yours sincerely,

Michael H. Vels
Chief Financial Officer

Vice President-Regulatory Affairs

Hydro One Limited / Hydro One Inc.
Submission to the Board of Directors

Date: February 10, 2017

Re: Distribution Filing

This memorandum outlines the form and key components of the Company's upcoming Distribution rate application. The application is consistent with the business plan that was approved by the Board in December 2016, except as otherwise noted.

A. Form of Application – Custom Incentive Rate-Setting Mechanism

In Ontario, the OEB is required by its governing statute to give rate-regulated utilities the opportunity to recover their reasonably incurred costs of providing utility service. The OEB Act gives the regulator wide latitude in the tools that it uses to fulfill this requirement, allowing it to use "any method or device" to set utility rates.

The OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE) was issued in October 2012 and provides three rate-setting options pursuant to which a distributor may apply for rates:

- 4th Generation Incentive Rate-Setting (also referred to as Price Cap IR);
- Custom Incentive Rate-Setting (Custom IR); and
- Annual Incentive Rate-Setting Index (Annual IR Index).

In October 2016, the OEB completed its review of the RRFE and released its *Handbook for Utility Rate Applications* ("Handbook"). In the Handbook, the OEB outlines the key principles and expectations that it will apply when reviewing applications for rates and also indicates that the rate-setting policy would be applied to all rate-regulated utilities going forward, not only electricity distributors. In addition, the OEB determined that going forward the policy would be referred to as the Renewed Regulatory Framework (RRF).

Hydro One Distribution previously applied for distribution rates using a Custom Incentive Rate-Setting approach and filed a "custom cost of service" application with the OEB for electricity distribution rates and other charges for five years effective 2015 to 2019. In its decision, the OEB found that the rate-setting approach set out in the application did not meet the intent of the RRF. The OEB approved distribution rates for the 2015 to 2017 period, inclusively.

The OEB expects that Hydro One Distribution's application for 2018 to 2022 rates will fully comply with the RRF. Regulatory Affairs analysed the Price Cap IR and Index IR, as described, to determine whether these available rate-setting options could be used for the purpose of the 2018 to 2022 Distribution application. We concluded that these two rate-setting approaches would not result in sufficient rates revenue to address the expected growth in Hydro One Distribution's costs over the rate-setting period, largely arising from the need for significant investments in power system infrastructure.

Renewed Regulatory Framework

The OEB's RRF intends to provide alignment between a sustainable, financially viable electricity sector with customers' expectations for reliable service at a reasonable price. The OEB believes that emphasizing outcomes, as opposed to activities, will result in better responsiveness to customer preferences, enhance distributor productivity, and promote innovation.

The RRF is focused on driving four performance outcomes:

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved. Utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: Utilities deliver on obligations mandated by government; and
4. Financial Performance: Financial viability is maintained and savings from operational effectiveness are sustainable.

The RRF performance outcomes are to be achieved by three regulatory approaches:

- Three incentive-based rate setting options, as noted above, designed to incent continuous productivity improvement;
- Five-year asset plans to support all rate applications; and
- Performance measurement.

The Handbook stipulates that a comprehensive rate application has three main components:

- **Business Plan** – including the overall strategy for the regulated business, utility goals, how the goals relate to what is sought in the application and the plan to meet them. The business plan should be supported by system plans, capital and operating plans, benchmarking, external reviews and customer engagement activities;

- **Historical and Forecast Information** – historical information (2013 to 2016, inclusively for capital and 2014 to 2016, inclusively for OM&A), a bridge-year (forecast 2017), and information relating to the five prospective test years (2018 to 2022 for capital and 2018 only for OM&A), the purpose of which is to demonstrate the continuity of the utility over time and allow a thorough review of proposed rates; and

- **Rate Models** – as crafted by the OEB for use as one of the tools to enhance the efficiency, consistency and accuracy of the review process.

Hydro One Distribution's primary challenge in this application is to establish that the proposed 2018 to 2022 distribution rates profile:

- Appropriately balances or aligns three competing but equally important factors: (i) customer needs and preferences; (ii) responsible stewardship of the company's distribution system; and (iii) customer rates;

- Reflects objectively demonstrated, measurable and sustainable continuous improvements; and

- Reflects costs that result in outcomes that customers value.

B. 2018 to 2022 Custom Incentive Rate-Setting (Custom IR): Key Elements

Hydro One Distribution intends to file a 5-year Custom Incentive Rate-Setting application that features the following key "custom" features:

- A rebasing of rates in 2018;
- Annual adjustments for inflation and productivity in 2019 through 2022;
- Integration, for rate setting purposes, of Norfolk, Haldimand and Woodstock, (the "Acquired Utilities") in 2021, along with the introduction of new rate classes;
- Midterm adjustments of the ROE and Load Forecast in 2021, coincident with the integration of the Acquired Utilities; and
- A capital factor to allow for the added revenue requirement required to recover rate base growth over the rate-setting period.

<u>Financial Metrics - Hydro One Distribution Application</u>

Hydro One Distribution's application will reflect the Distribution Investment Plan for the five year period 2018 to 2022 as described the Distribution Business Plan 2017 to 2022 that was approved by the Board on December 2, 2016. The financial metrics set out below are different from the approved Business Plan only as they relate to the treatment of the Acquired Utilities, which does not impact estimated increases in rates or estimated total bill impacts.

Table 1. Financial Metrics 2018 to 2022 Hydro One Distribution Application

Distribution Revenue Requirement	2017	2018	2019	2020	2021	2022
	OEB Approved					
Capital Expenditures	$ 661	$ 634	$ 757	$ 719	$ 741	$ 827
In-Service Additions	$ 696	$ 641	$ 776	$ 768	$ 734	$ 815
Rate Base	**$ 7,190**	**$ 7,672**	**$ 8,049**	**$ 8,477**	**$ 9,035**	**$ 9,435**
OM&A	$ 593	$ 592	$ 600	$ 607	$ 626	$ 634
Depreciation	$ 390	$ 394	$ 414	$ 429	$ 448	$ 465
Return on Debt	$ 183	$ 191	$ 200	$ 211	$ 225	$ 235
Return on Equity	$ 253	$ 269	$ 283	$ 298	$ 317	$ 331
Income Tax	$ 49	$ 58	$ 61	$ 63	$ 69	$ 70
Revenue Requirement	**$ 1,468**	**$ 1,505**	**$ 1,558**	**$ 1,607**	**$ 1,685**	**$ 1,735**
Rate Riders	$ 11	$ 23	$ 23	$ 23	$ 23	$ 23
Other revenue impacts	$ (53)	$ (49)	$ (49)	$ (49)	$ (50)	$ (50)
Rates Revenue Requirement	**$ 1,426**	**$ 1,479**	**$ 1,532**	**$ 1,581**	**$ 1,658**	**$ 1,707**
Rate Increase Required, excluding Load		**3.7%**	**3.6%**	**3.2%**	**4.9%**	**3.0%**
Estimated Load Impact		2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Rate Increase Required		**5.7%**	**3.4%**	**2.5%**	**2.4%**	**2.4%**
Estimated Total Bill Impact (R1 customer - 30%)		**1.7%**	**1.0%**	**0.7%**	**0.7%**	**0.7%**

The drivers of the proposed distribution rate increases over the 2018 to 2022 period are set out in Table 2. The average rate increase over the 5-year period is 3.3%. As discussed in November 2016, approximately 5.1% or 90% of the rate increase in 2018 is attributable to factors that cannot be controlled at this time by Hydro One. Proposed increases in rates in 2019 through 2022 are driven by planned capital additions in each year, consistent with the Distribution Business Plan approved by the Board in December 2016.

Table 2. Drivers of Proposed Distribution Rates Increases 2018 to 2022

Distribution Rate Drivers	**2018**	**2019**	**2020**	**2021**	**2022**
OM&A	-0.1%	0.5%	0.5%	1.2%	0.5%
Rate Base & Depreciation	2.0%	2.9%	2.6%	3.3%	2.5%
Income Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Rate Riders	0.8%	0.0%	0.0%	0.0%	0.0%
Estimated Load Impact	2.0%	-0.2%	-0.7%	-2.5%	-0.6%
External Revenues - Other	0.3%	0.0%	0.0%	-0.1%	0.0%
Total	5.7%	3.4%	2.5%	2.4%	2.4%

The estimated total bill impacts noted above do not yet reflect the final 2018 to 2022 load forecast, which will be reflected in the actual pre-filed evidence. In addition, there are several updates that must be made that may have further, unavoidable implications for the bill impacts. The update of this evidence, currently planned for early June 2017 includes:

- Integration of actual 2016 year-end financial data, including deferral and variance account balances that inform the calculation of Rate Riders; and
- Receipt of a new actuarial valuation report, that could reduce the total cash pension cost by approximately $25 million to $85 million from $110 million currently (Hydro One Distribution and Transmission).

<u>Key Messages and Themes</u>

The planned application for distribution rates is consistent with the corporate vision, values and strategy for the regulated business set out in Hydro One's Distribution Business Plan; it illustrates how the company's business objectives and values align with the OEB's RRF, and also associates business objectives with the choices inherent in the Distribution System Plan.

In particular, the application includes the following key messages:

- Hydro One's new commercial orientation means that the company is customer focused, drives company-wide efficiency and productivity, and demonstrates corporate accountability for performance outcomes;

- Hydro One's executive leadership and Board of Directors are committed to building a strong performance management culture and the ability to measure and track performance is essential to this vision;

- Hydro One's vision, strategy and values inform everything the company does, as it works to align three competing but equally important factors: customer needs and preferences, responsible stewardship of its distribution system, and customer rates;

- The approach has been shaped by: (i) the company's commitment to reduce costs and increase productivity and efficiency before asking customers to pay more; (ii) directing investment to address specific identified customer needs and preferences; (iii) reducing or deferring investment levels to where any tradeoff with respect to reliability can reasonably be justified by lower rates; and (iv) the evaluation of the resulting rates profile for the 2018 to 2022 period in the context of customer feedback from Hydro One Distribution's 2016 customer engagement process and the backdrop of increasing electricity prices; and

- Previous direction by the OEB that the company's distribution system is in need of additional investment and the company should be finding cost effective ways to improve its reliability performance.

Custom IR Design Features

Custom IR Design Feature	Description
Revenue Cap versus Price Cap	**Revenue Cap** – form of incentive regulation in which utility ***revenue*** for the test year t+1 is equal to the revenue in year t inflated by an Annual Adjustment Mechanism, comprised of inflation and productivity factors. For example and as set out in Appendix A, 2019 revenue requirement is equal to the revenue requirement in 2018 inflated by the Annual Adjustment Mechanism. **Price Cap** – form of incentive regulation in which utility ***rates*** for the test year t+1 are equal to utility rates in year t inflated by an Annual Adjustment Mechanism. The recommended Custom IR approach is a Revenue Cap. This approach: (i) is more consistent with Hydro One's business planning process and the Total Custom Incentive Revenue for Rates can be easily reconciled to the Rates Revenue Requirement estimated for the test period by Business Planning; (ii) gives the company the needed flexibility to introduce a new rate class in 2021 to fully integrate the acquired LDCs in a manner consistent with prior determinations of the OEB; (iii) permits the continued transition to fully-fixed rates for residential customers and flexibility for any future OEB decisions regarding rate design changes for small business customers; (iv) provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the Seasonal Rate Class over the 2018 to 2022 Custom IR term; (v) provides adequate flexibility regarding the OEB's rate design initiative for Electricity Commercial and Industrial Customers; (vi) allows the company to update its billing determinants to reflect estimated changes in the load forecast over the IR term; and (vii) more easily accommodates the planned Capital Factor. 2018 rates revenue requirement (i.e., for the first year of the five-year term) is determined using a Cost of Service Approach, consistent with the OEB's RRF.
Annual Adjustment	The recommended Annual Adjustment Mechanism is consistent with

Mechanism (1+Inflation Factor-TFP-SF)	the OEB's RRF policy direction for Custom IR. Specifically, the RRF provides that the allowed rate of change in the rates/revenue over the term of the Custom IR will be determined on a case by case basis, informed by empirical evidence that includes: (i) distributor's forecasts (revenues and costs, including inflation and productivity); (ii) the OEB's inflation and industry productivity analyses; and (iii) benchmarking to assess the reasonableness of distributor forecasts. The RRF policy also stipulates that expected inflation and productivity gains will be built into the rate adjustment over the term of the Custom IR. The recommended Custom IR rate-setting approach is consistent with these expectations. Hydro One Distribution has obtained its own third-party expert estimation of industry Total Factor Productivity and has also retained a third-party expert to estimate, using an econometric benchmarking approach, a Hydro One Distribution-specific Productivity Stretch Factor, consistent with the OEB's requirements as set out in the Handbook. As a result of this analysis, Hydro One Distribution will seek approval to use the OEB's Inflation Factor, Industry Total Factor Productivity of 0%, and a utility-specific Productivity Stretch Factor of 0.6%. The OEB's Inflation Factor is determined annually by the OEB and is 1.9% for 2017. The Inflation Factor would be adjusted in each of 2019 to 2022. Industry Total Factor Productivity and the utility-specific Productivity Stretch Factor would not be subject to annual adjustment. In other words, rates are increased for inflation, increased/decreased for industry-wide productivity, and reduced further by a utility-specific productivity factor that depends on the relative cost performance of the utility versus all distributors in Ontario. Since 2013, the productivity factor used by the OEB for the industry has been set at 0%, as industry productivity has been negative, meaning that the industry is getting less efficient. Rate increases would therefore be greater than inflation. Hydro One Distribution's productivity stretch factor reflects the company's cost performance in relation to the industry, and currently indicates the necessity for a 0.6% factor; a built-in expectation that cost improvement of at least

	0.6% per year is required.
Capital Factor	The Custom Capital Factor creates revenue neutrality with Hydro One Distribution's Business Planning rates revenue requirement in each of 2018 to 2022, excluding the effect of the Productivity Stretch Factor. Specifically, it is designed to provide for the additional revenue requirement that results from: (i) the level of capital investment, ins-service additions, and rate base growth required by Hydro One Distribution and (ii) the added rate base associated with the Acquired Utilities for rate-setting purposes. This approach, excluding the integration of rate base associated with the Acquired Utilities, was previously tested and accepted by the OEB in the recent Toronto Hydro decision.
OM&A Associated with Acquired Utilities	The proposed Custom IR rate-setting approach contemplates that the residual/incremental operating costs of the three Acquired Utilities be added to the revenue requirement in 2021. If this did not occur, Hydro One would lose the revenue related to these LDC's as their deferral periods end, but would still be incurring the OM&A related to supporting these businesses.
Cost of Capital	Hydro One Distribution's application contemplates that the cost of equity and cost of debt are updated for the 2018 cost of service or rebasing year. Hydro One will also apply to update the cost of capital in 2021, as a mid-term adjustment. While this feature may be viewed as being inconsistent with the OEB's direction in the Handbook, the adjustment is consistent with: (i) proposal to integrate the Acquired Utilities in 2021; (ii) introduction of new customer rate classes; and (iii) proposal to refresh the Load Forecast for 2021 and 2022.
Earnings Sharing Mechanism (ESM)	An ESM is not a required feature of a Custom IR. However, in order to address the OEB's expectations that the structure of the Custom IR contain features that align the interests of customers with those of the utility and provide a degree of protection to customers, Hydro One Distribution intends to include an ESM in the application. Hydro One Distribution will share with customers 50% of any earnings that exceed the regulatory ROE reflected in Custom IR by more than 100 basis points in any year of the Custom IR term. The customer share of

	the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One Distribution's next rebasing, presently assumed to be in 2023.
Capital In-Service Variance Account (CISVA)	A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year. If in-service additions in a year are less than the OEB-approved level, the balance of the account would be negative and refunded to customers in a future rate-setting period. If actual in-service capital additions are equal or greater than the OEB-approved level in the year, no entry would be recorded in the account Hydro One Distribution does not currently have a CISVA. However, it is a standard feature in most Custom IRs approved by the OEB, and is familiar to the OEB and intervenors from Hydro One's Transmission applications. Hydro One Distribution intends to include a proposed CISVA in the pre-filed evidence that has the following key features: (i) Purpose is to track the impact on revenue requirement of any in-service additions that are lower than 98% of the OEB-approved amount for each year of the Custom IR term; (ii) For cumulative in-service additions that are 98% of the OEB-approved level or less, the associated revenue requirement impact will be computed and tracked on an annual basis; (iii) At the end of the five-year term of the Custom IR Plan in 2023, the sum of the variances in each year will be disposed of for the benefit of customers; (iv) Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and (v) Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry is made in the variance account and no amount is recoverable from ratepayers. Should in-service additions, on a cumulative basis over the term of the

	Custom IR, exceed the cumulative OEB-approved in-service additions for the same period, the OEB will consider whether it is appropriate to recover this difference in rates at the time of the next rebasing, currently anticipated to be 2023. This is consistent with current OEB practice.
Treatment of Unforeseen Events (Z-Factor Claims)	Hydro One Distribution will continue to have access to this existing OEB mechanism that allows distributors to apply to the OEB to recover costs associated with unforeseen events that are outside the control of a distributor's ability to manage. The cost must be material (in excess of $1 million), its causation clear, and the amount must have been prudently incurred. The materiality thresholds must be met on an individual event basis in order for the distributor to apply for recovery of the relevant costs. The use of a Z-Factor Claim is subject to a number of specific Filing Guidelines. For example, storm costs that are in excess of $1 million are not eligible for Z-Factor treatment if the storm related costs reflected in rates have not been fully incurred for that year.
Off-Ramps	A regulatory review may be triggered if Hydro One Distribution's earnings are outside of a dead band of +/- 300 basis points from the OEB-approved return on equity. No specific provision for this is needed in the Application.
Customer Classes	Hydro One Distribution is proposing to maintain the following existing customer classes until 2021: • **Residential:** High Density (UR), Medium Density (R1), Low Density (R2) and Seasonal; • **General Service:** Energy Billed (<50kW), Demand Billed (≥50 kW), Urban High Density, and Non-urban Density; • **Sub-Transmission:** connected at >13.8 kV, supply own transformation, >500 kW, and includes all embedded distributors; and • **Other:** Street and Sentinel Lighting, Unmetered Scattered Load, and Distributed Generation. Hydro One Distribution also intends to seek OEB approval for new

	residential and general service rate classes, effective January 1, 2021, consistent with the OEB's MAADs Decisions[1], to integrate the Acquired Utilities. Other rate classes that exist in the acquired utilities (such as Streetlight, Sentinel Light, Unmetered Scattered Load and Large Users) would be moved to existing Hydro One Distribution rate classes. These new rate classes would be approved by the OEB for use commencing January 1, 2021. It is not expected that, at the time of the Application, the OEB would have decided on the elimination of the Seasonal Rate Class or on Commercial & Industrial rate design. As such, the proposed filing will assume the 'status quo' for these customers.
Cost Allocation and Rate Design	Changes to Hydro One Distribution's cost allocation (e.g., due to possible elimination of the seasonal rate class and incorporating the new acquired rate classes), as well as changes to rate design previously approved by the OEB (e.g., transition to fully-fixed rates for residential customers) will continue during the Custom IR term. Cost allocation relates to the process of apportioning the OEB-approved revenue requirement amongst Hydro One Distribution's rate classes on the basis of cost causality. Rate Design refers to how utility rates are charged to each customer class and are a function of: (i) identified charge determinants that include the number of customers in each class, kWh consumption, or kW peak load; and (ii) whether rates will be assessed as a fixed monthly charge ($/customer) or on a volumetric basis ($/kWh or $/kW). The OEB does not consider material changes to Cost Allocation and Rate Design in the context for an application for distribution rates, due to the industry-wide policy implications associated with proposed changes. Initiatives relating to the Elimination of the Seasonal Rate

[1] Ontario Energy Board. Decision and Order – Norfolk Power Distribution Inc. EB-2013-0187. July 3, 2014.
Ontario Energy Board. Decision and Order - Haldimand County Hydro Inc. EB-2014-0244. March 12, 2015.
Ontario Energy Board. Decision and Order – Woodstock Hydro Services Inc. EB-2014-0213. September 11, 2015.

	Class (EB-2013-0416/EB-2016-0315), Residential Rate Design/Decoupling (EB-2007-0031, EB-2010-0060 and EB-2012-0410), and Rate Design for Distribution Commercial and Industrial Customers (EB-2015-0043) have all been or in the process of being addressed in separate OEB-sponsored policy processes.
Deferral and Variance Accounts	Deferral and variance account balances as of the end of 2016 will be cleared in this Application. Over the Custom IR period, deferral and variance account balances will continue to be used and balances cleared in a manner consistent with OEB policies. These balances are set out in Table 1 in the "Rate Riders" line item. Estimated costs of $23 million are forecast to be recovered from customers in 2018.

Regulatory Policy Issues

Regulatory Policy Issue	Description
Status of Transmission Application – Implication for Distribution Application for 2018 to 2022 Rates	The OEB is not expected to issue its Decision and Order relating to Hydro One Transmission's application for 2017 and 2018 rates (EB-2016-0160) prior to the planned March 31, 2017 filing date of the Distribution Application. There are a significant number of common regulatory policy issues. The issuance of a Decision and Order by the OEB that is inconsistent with the filing position on shared regulatory policy issues may cause the consideration of the Distribution application to take longer, require additional updates to pre-filed evidence, or result in additional interrogatories and undertakings arising from the technical conference and oral hearing.
Comprehensive Customer Engagement	Hydro One Distribution has undertaken a comprehensive Customer Engagement process, consistent with the RRF and the OEB's Filing Requirements for Electricity Distribution Rate Applications. At issue will be: (i) whether the Customer Engagement process meets the OEB's Filing Requirements; (ii) whether it was designed to identify customer needs and preferences; (iii) whether customer needs and preferences were identified; (iv) how identified needs and preferences informed the investment and operating plans set out in the pre-filed evidence; and (v) whether Hydro One Distribution has adequately responded to the feedback from customers in a manner that produces

	tangible and measurable outcomes that are valued by customers. We believe that the Application will satisfy all of these requirements.
Other Stakeholdering and Engagement /Discussions	In its 2015 Decision, the OEB provided some generally positive feedback to Hydro One on its stakeholdering efforts. The application will include documentation of the various stakeholder engagements that Hydro One held with intervenors on the subjects of the various productivity and benchmarking studies, the customer engagement and the proposed revenue requirement and form of the Application. Also included will be a report on the First Nations and Metis engagements that will have been held in advance of the filing.
First Nations and Métis Engagement	On February 9 and 10, 2017, Hydro One is hosting Hydro One First Nations Engagement sessions to build on its relationships with First Nations communities and Chiefs. The planned Hydro One Distribution Application will be discussed at these sessions. First Nations customers were engaged as part of the above noted comprehensive Customer Engagement Process, however it was determined that additional, direct dialogue with community Chiefs relating to the Application would be beneficial. In addition, through the use of a moderator and note taker, Hydro One will be gathering information relating to First Nations' thoughts and goals, consistent with the Company's desire to build a new vision for our collective futures. A similar session is planned for Hydro One's Métis customers on February 22. During these sessions, should First Nations and/or Métis leaders express a desire to obtain additional information or education about the planned Distribution Application, Hydro One will make the appropriate arrangements to ensure that these needs are met.
Compensation	Consistent with the filing position for the Application for 2017 and 2018 Transmission Rates, LTIP, STIP, stock-based compensation costs and costs related to the Employee Share Ownership Plan should be recoverable in rates and are a component of normal total compensation. Four compensation issues will likely be tested during the proceeding: (i) size of total compensation "envelope"; (ii) composition of compensation costs; (iii) executive compensation; and (iv) whether Hydro One's OEB-approved Cost Allocation remains

	appropriate. Hydro One's Distribution Application will be supported by a compensation benchmarking study.
Regulatory Treatment of Pension and OPEB Costs	The OEB is presently holding a consultative initiative to develop standard principles to guide the OEB's review of pension and OPEB costs for the future, to establish specific information requirements for applications, and to consider appropriate regulatory mechanisms for cost recovery which could be applied consistently across the gas and electricity sectors for rate-regulated entities. The Custom IR application will reflect Hydro One Distribution's current, OEB-approved regulatory treatment of pension and OPEB costs – cash and accrual, respectively. It is not clear whether regulatory policies relating to the cost recovery of pension or OPEB costs will change, what that change would be, or when that change would be effective. Regulatory tools to protect Hydro One Distribution from the adverse financial effect of a potential change in cost recovery of OPEB Costs will be considered, once the consequences of any change to policy are quantified. Hydro One Distribution plans to request the OEB's approval to transition to an updated regulatory approach, if any such change occurs, at the time of Hydro One Distribution's next rebasing in 2023.
Taxation Rates and Deferred Tax Asset	The application will reflect a combined Federal and Provincial income tax rate of 26.5% for ratemaking purposes. Consistent with the filing position for the Transmission Application for Rates, based on regulatory principles ("stand-alone" and "benefits follow costs") and guidance from previous OEB determinations, the shareholder alone should own the benefit associated with the deferred tax asset.
Response to OEB-Mandated Studies	The OEB Ordered the completion of the following reports in order to inform its assessment of Hydro One Distribution's efficiency and productivity, and to assist with its assessment of whether applied-for costs are reasonable, in the context of the company's next application for rates: • Total Factor Productivity (TFP) Study (see below); • Total Compensation Study (as noted above);

	• Vegetation Management Program and Trend Analysis; • Third-party Review of the Distribution System Plan; • Pole Replacement Program; • Distribution Station Refurbishment Program; • Miscellaneous Service Charges; • Depreciation Study; and • In-Service Capital Additions Variance Analysis. The implications and consequences of these reports will be reflected in Hydro One Distribution's capital and operating plans. Strategies and actions to address identified areas will need to be comprehensively set out in the application and the pre-filed evidence.
Cost Efficiencies, Productivity and Performance Management	KPIs, performance metrics and outcome measurement contained in and resulting from the foregoing OEB-Mandated Studies are expected to be integrated into the company's performance measurement approach. In its Decision relating to Hydro One Distribution's application for 2015 to 2019 Distribution rates, the OEB also created an expectation that Hydro One Distribution would improve its performance and outcome measurement, demonstrate the financial and unit cost benefit arising from productivity and other continuous improvement initiatives, and demonstrate that the company provides value for customers. As stated by the OEB in its July 28, 2016 Decision and Order for EB-2015-0089 for Milton Hydro Distribution Inc., utilities that objectively demonstrate measurable and sustainable continuous improvements can expect to have their test period revenue requirement requests approved without material disallowances. Measurement tools include: (i) productivity indicators: input/output metrics; (ii) KPIs: track how well the utility is achieving its stated plans and accomplishments; and (iii) Outcome measures: creating value for money or results that are valued by Customers
Total Cost Benchmarking – Pacific Economic Group (PEG) Model	As set out by the OEB in the recent PowerStream Decision and Order, "the OEB has previously determined that both external benchmarking and internal benchmarking that tracks year-over-year productivity improvements are key in providing the confidence for long-term rate

	setting under the principles of the RRFE"[2]. The OEB has used an econometric model to externally and internally benchmark utility productivity on a historical basis. It is this model that benchmarks Hydro One Distribution's annual cost performance, places the company in the 4th quartile, and results in the assignment of a 0.6% Productivity Stretch Factor. This model reflects the "average" Ontario utility and does not reflect Hydro One Distribution's particular circumstances. The OEB has signalled its intention to use this model to predict forecast costs. New OEB filing requirements contemplate that Hydro One Distribution will be required to run and file the output of this model, as it relates to the prediction of future 2018 costs, with the OEB. Hydro One currently intends to run this model and file the results with the OEB as part of a "Blue Page" update to the application once 2016 audited year-end financial metrics are available. Hydro One expects this update to be filed in late-May or early-June 2017. Hydro One Distribution will be required to provide evidence to support the difference or "gap" between econometrically predicted and applied-for costs, notably in the 2018 rebasing year and must be able to demonstrate that it will be able to "live within its means" over the remainder of the 2019 to 2022 term. Although the OEB has also stated in a number of previous decisions "that it will use benchmarking as a tool to inform its decisions, but will not use it as a method by which to determine rates"[3], it appears that the weight the OEB places on the approach to establish the reasonableness of costs may be increasing. Hydro One Distribution is presently ranked by the OEB in the fourth quartile versus its peer group and the recommended 0.6% Productivity Stretch Factor is consistent with that established for other fourth quartile performers.
Lost Revenue	As a result of updated OEB policies and guidelines, there is a high

[2] Ontario Energy Board. Decision and Order – PowerStream Inc. EB-2015-0003. August 4, 2016. Page 9.
[3] Ontario Energy Board. Decision and Order – Toronto Hydro Electric System Limited. EB-2014-0116. Page 19

Adjustment Mechanism Deferral and Variance Accounts - LRAMVA	probability that Hydro One Distribution will be expected to track the variance between the OEB-approved Conservation Demand Management ("CDM") adjustment to its load forecasts and the actual (verified) CDM results in a variance account called the LRAM Variance Account (LRAMVA), consistent with the OEB's Filing Requirements for Electricity Distribution Rate Applications. Hydro One Distribution does not currently have an LRAMVA account. Should this account be required, Hydro One Distribution would apply to dispose of any balance in this account at the time of its next rebasing, which is presently assumed to be 2023.
Working Capital Allowance	The application will include a proposal for working capital as determined by a lead-lag study to be conducted by Navigant, a third party expert, which is now complete. The lead-lag study conducted for Hydro One Distribution's established a working capital requirement of approximately $321 million or 7.7% of total OM&A and Cost of Power amounts for 2018. Working capital is included in the calculation of mid-year rate base.

Appendix A highlights the operation of the proposed Custom IR rate-setting methodology graphically, consistent with the briefing documents previously provided to the Board, but updated for actual numbers.

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: November 10, 2017

Re: Changes to Forestry Plan - Optimal Cycle Protocol (OCP)

Hydro One has developed a new vegetation management strategy and program called the Optimal Cycle Protocol. This new strategy and program will reduce safety risks, improve reliability, reduce the total program costs, and increase customer satisfaction. The attached Briefing Note and presentation are to update the Board on the transition to the new strategy and program.

Yours sincerely,

Greg Kiraly
Chief Operating Officer

Brad Bowness
VP, Distribution

Darlene Bradley
VP, Planning

BriefingNote

hydro one

Date: November 10, 2017

Presented by: Brad Bowness

Overview:

Hydro One is implementing a new vegetation management strategy called the Optimal Cycle Protocol which will transition the company to an industry leading three year cycle. By 2021, the Optimal Cycle Protocol will improve vegetation management outcomes by: reducing safety risks, improving reliability, improving unit cost, and increasing customer satisfaction.

Investment Details:

Hydro One's distribution vegetation management program has been a key focus of the Ontario Energy Board (OEB), the Auditor General of Ontario and Hydro One's internal audit department, all of which suggested improvements in program planning and execution were required. Industry peer benchmarking has also positioned Hydro One unfavourably on unit costs, reliability and maintenance cycle length.

Hydro One distribution manages about 104,000 right-of-way kilometers to reduce the likelihood of a vegetation outage and to mitigate public safety risk. Vegetation related outages account for about 30% of System Average Interruption Duration Index (SAIDI) based on the three year average and projected to be over 40% by year-end 2017. Hydro One's performance is 4th quartile relative to industry peers. Deferred spending has resulted in maintenance cycles of approximately ten years, which is much longer than industry average, and has been identified as the largest contributor to poor reliability performance.

Working with Clear Path Utility Solutions LLC over the last six months, Hydro One developed a new program called the Optimal Cycle Protocol. This new program will patrol Hydro One's rights-of-ways on a three year cycle, generate defect-based work prescriptions, and correct through trimming and/or removing, trees that can grow into our distribution lines, along with dead, dying, or diseased trees that can fall into our lines. The Optimal Cycle Protocol will help Hydro One gain valuable system information, improve right-of-way asset condition and provide the opportunity to optimize the maintenance approach for each feeder to improve public safety, reduce risk of wildfire and improve system reliability within the current approved budget. This new program allows Hydro One to manage more kilometers of right-of-way with the same budget.

The transition to the Optimal Cycle Protocol started in September 2017 where the program strategy was rolled out to the field and employees were trained on the new work standards. The work from September 2017 to December 2017 is being closely monitored to ensure that the new program approach is achieving the desired objectives. By mid-November100% of the forestry technicians will be trained on the Optimal Cycle protocol and by year end about 2,380 km of tree trimming and removal will be completed according to the new standard. It is expected that by January 1st 2018, a stable and sustainable Optimal Cycle Protocol will be implemented across the Province.

Brad Bowness /November 2, 2017 10:30pm

Table 1. Financial Metrics 2018 to 2022 Hydro One Distribution Application

Distribution Revenue Requirement	2017	2018	2019	2020	2021	2022
	OEB Approved					
Capital Expenditures	$ 661	$ 634	$ 757	$ 719	$ 741	$ 827
In-Service Additions	$ 696	$ 641	$ 776	$ 768	$ 734	$ 815
Rate Base	**$ 7,190**	**$ 7,672**	**$ 8,049**	**$ 8,477**	**$ 9,035**	**$ 9,435**
OM&A	$ 593	$ 592	$ 600	$ 607	$ 626	$ 634
Depreciation	$ 390	$ 394	$ 414	$ 429	$ 448	$ 465
Return on Debt	$ 183	$ 191	$ 200	$ 211	$ 225	$ 235
Return on Equity	$ 253	$ 269	$ 283	$ 298	$ 317	$ 331
Income Tax	$ 49	$ 58	$ 61	$ 63	$ 69	$ 70
Revenue Requirement	**$ 1,468**	**$ 1,505**	**$ 1,558**	**$ 1,607**	**$ 1,685**	**$ 1,735**
Rate Riders	$ 11	$ 23	$ 23	$ 23	$ 23	$ 23
Other revenue impacts	$ (53)	$ (49)	$ (49)	$ (49)	$ (50)	$ (50)
Rates Revenue Requirement	**$ 1,426**	**$ 1,479**	**$ 1,532**	**$ 1,581**	**$ 1,658**	**$ 1,707**
Rate Increase Required, excluding Load		**3.7%**	**3.6%**	**3.2%**	**4.9%**	**3.0%**
Estimated Load Impact		2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Rate Increase Required		**5.7%**	**3.4%**	**2.5%**	**2.4%**	**2.4%**
Estimated Total Bill Impact (R1 customer - 30%)		**1.7%**	**1.0%**	**0.7%**	**0.7%**	**0.7%**

The drivers of the proposed distribution rate increases over the 2018 to 2022 period are set out in Table 2. The average rate increase over the 5-year period is 3.3%. As discussed in November 2016, approximately 5.1% or 90% of the rate increase in 2018 is attributable to factors that cannot be controlled at this time by Hydro One. Proposed increases in rates in 2019 through 2022 are driven by planned capital additions in each year, consistent with the Distribution Business Plan approved by the Board in December 2016.

Table 2. Drivers of Proposed Distribution Rates Increases 2018 to 2022

Distribution Rate Drivers	2018	2019	2020	2021	2022
OM&A	-0.1%	0.5%	0.5%	1.2%	0.5%
Rate Base & Depreciation	2.0%	2.9%	2.6%	3.3%	2.5%
Income Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Rate Riders	0.8%	0.0%	0.0%	0.0%	0.0%
Estimated Load Impact	2.0%	-0.2%	-0.7%	-2.5%	-0.6%
External Revenues - Other	0.3%	0.0%	0.0%	-0.1%	0.0%
Total	5.7%	3.4%	2.5%	2.4%	2.4%

Estimated Costs:

The Optimal Cycle Protocol will be executed within the proposed five year budget 2018 – 2022 (Table 1). In addition, there is a separate project (currently estimated at $5M capital investment) to deliver a supporting IT tool to manage work more efficiently.

Table 1 - Vegetation Management Budgets

	2015	2016	2017	2018	2019	2020
OEB Approved	$129.0M	$164.6M	$167.3M	N/A	N/A	N/A
OEB Units (as filed)	10,200 km	14,250 km	14,250 km	21,250 km	-	-
HONI Approved Budget	$129.4M	$145.7M*	$138.5M*	-	-	-
HONI Proposed Budget	-	-	-	$149.6M	$150.0M	$152.4M
YE Actual	$118.0M	$142.9M	$129.3M**	N/A	N/A	N/A
Actual Units and Forecast	10,366 km	11,753 km	20,500 km	34,333 km	34,333 km	34,333 km

NOTE: The table above reflects three different strategic approaches with different scopes hence like for like comparison for units may not be applicable.

* Discrepancy between OEB approved and HONI approved is due to redirection to Customer Care and Trouble Calls.

** 2017 Forecast – September

Other Alternatives Considered:

Status Quo or Do nothing Alternative

The do nothing alterative was considered and rejected because continuing with the current vegetation management programs would not yield the desired safety, condition, reliability and cost outcomes within the Business Plan timeframe. Table 2, in the appendix below outlines some of the key differences between the Optimal Cycle Protocol and the current vegetation management strategy.

Regulatory Considerations:

The Optimal Cycle Protocol Project strategy was developed after the current distribution rate filing was submitted. Therefore, the concept of moving to a three year cycle and changing the work specifications is not currently described in the evidence.

There are two main regulatory considerations pertaining to the rate filing:

1. Explaining how this transition may affect the future of the vegetation management programs and how that affects the rate filing evidence, most importantly, the program budgets requested.
   - Hydro One has committed to operating within the approved vegetation management budget that will be outlined in the Ontario Energy Board's decision on the current rate application. It is expected that under the Optimal Cycle Protocol, investment outcomes will be noticeably improved prior to the next rate application.
2. Justifying a vegetation management strategy that improves reliability given the results of the rate filing customer consultation.
   - The primary driver of this strategy change is to manage affordability for our customers. With a significant reduction in cycle length there will be a cascading improvement to reliability that will provide our customers further value from the vegetation management programs ultimately reducing forestry costs and trouble call expenses.

Risks and Mitigation:

Resourcing – The Optimal Cycle Protocol requires a different labour mix than the traditional approach to vegetation management and will require increased administrative oversight and support.

Change Management – The Optimal Cycle Protocol requires a significant change to work specifications, resource requirements and generates new work in the form of project management and quality assessment that currently isn't in place within the existing Forestry Programs. Furthermore, the success of the Optimal Cycle Protocol hinges on quality data collection and strict adherence to the scope of work, which has been a challenge in the past. Change management activities are currently ongoing and the early stages of implementation are seeing a high degree of acceptance.

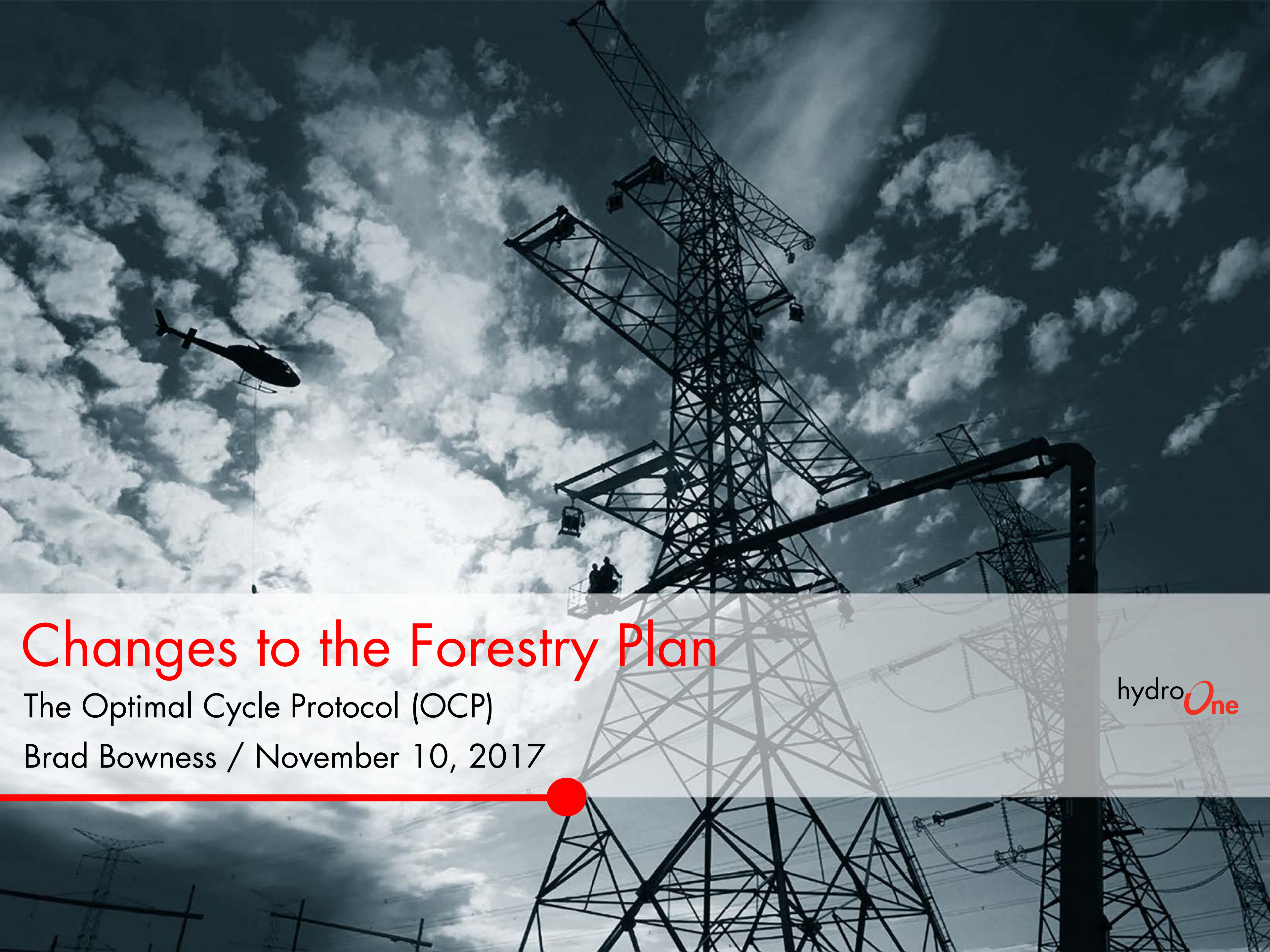
Information Technology – Forestry Services' is currently replacing their work management system as the existing Forestry Management System is at end of life. The Optimal Cycle Protocol requires enhanced data collection and detailed project management, both of which are not supported by the current forestry management system. As an interim solution, the Forestry Management System will continue to be used along with a supplementary data collection process that will require close monitoring to ensure data accuracy.

Long-Term Asset Condition and Future Maintenance Costs – The Optimal Cycle Protocol reduces the brush control being completed on the right of way floor. Some brush control will be completed to maintain access. Forest edge encroachment could increase population of trees capable of striking the power line over time and to mitigate this risk, adequate funding in the public safety and reliability program will be required.

Appendix

Table 2 - Comparison between the current vegetation strategy and the Optimal Cycle Protocol

	Historic Approach	**Optimal Cycle Protocol**
Scope/Approach	Full ROW clearing	Defect focused
Cycle/Frequency	10 years	3 years
Cost per unit	$12,000 / km	$3,600 / km
Units per year	10,500 km	34,666 km
Costs per year	$150M	$150M
Defects treated per year	800,000	700,000 to 800,000
Cost per defect	$120	$160
Impact to Reliability	Maintain current reliability	By 2022, we can expect a 40% improvement based on a 10 year average and a 58% improvement based on a 2017 year-end projection.
Cost Savings	N/A	$6M to $12M annual saving by 2023 due to reduced trouble calls and about $20M starting in 2023 due to on-cycle efficiencies
Environmental Consideration	Infrequent maintenance allowing for incompatible vegetation to establish requiring high intensity clearing	Frequent maintenance allow for a better managed utility forest
Customer Consideration	Infrequent, heavy vegetation management treatment with high aesthetic impact	Frequent, light touch vegetation management treatments with improved aesthetics and customer relations
Safety Consideration	6.5% of the tree utility forest has vegetation grow-in contacts	Less than 1% vegetation grow-in contacts after the 1st cycle. Reduced risk of public electrical contact and wildfire.



Changes to the Forestry Plan

The Optimal Cycle Protocol (OCP)

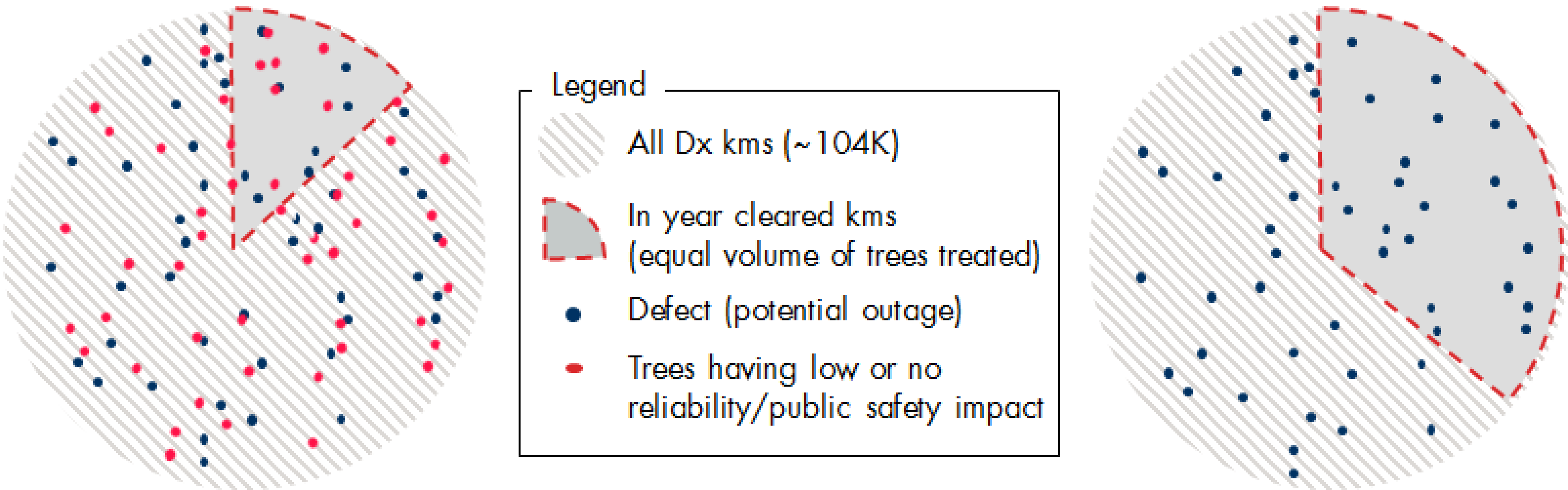
Brad Bowness / November 10, 2017

hydro One

The new strategy would cover the entire province in 3 years and increase the rate of critical defect removal

PREVIOUS STRATEGY FOCUSES ON CLEARING ~1/10TH OF LINE KMS

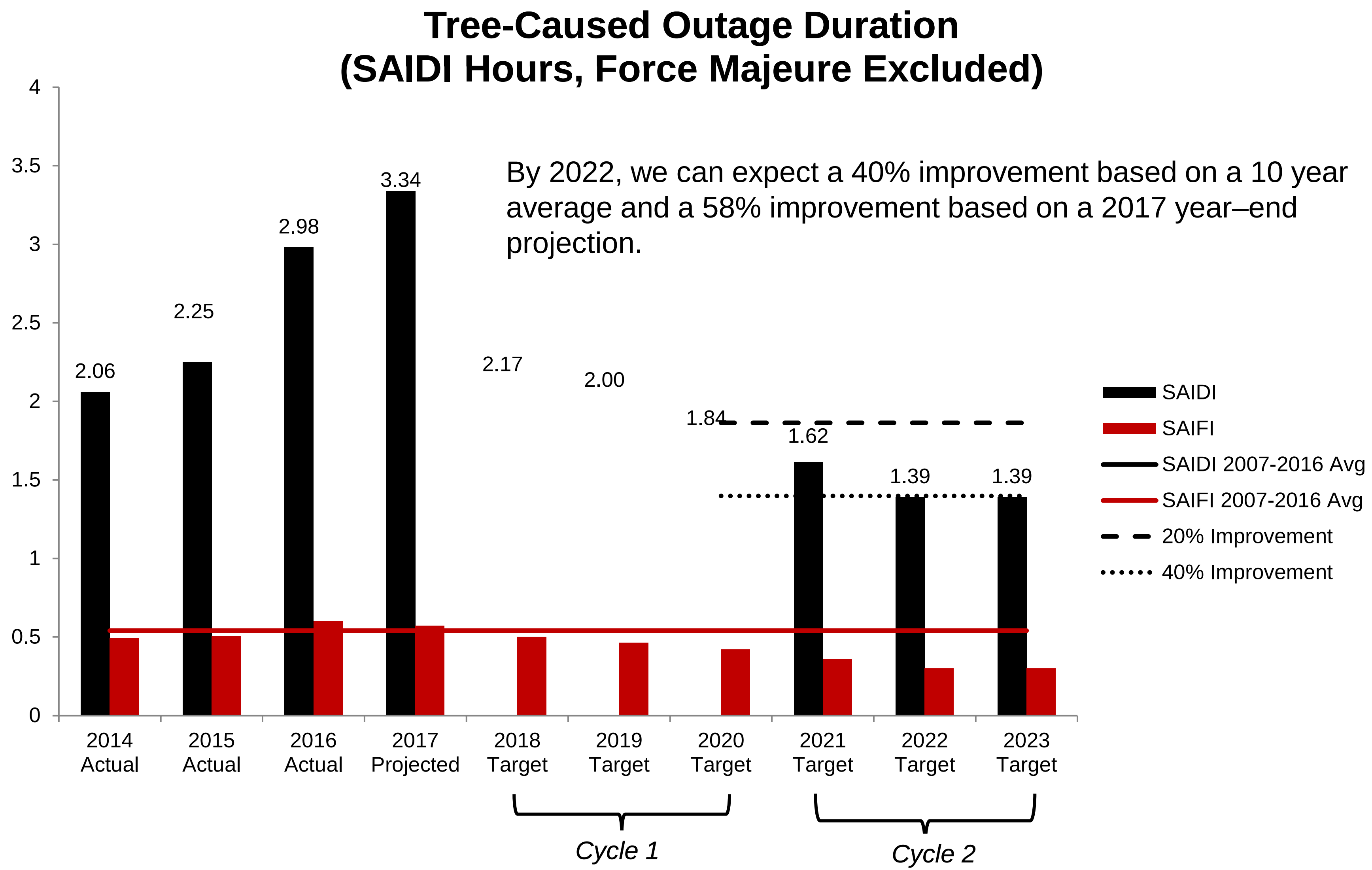
NEW STRATEGY TREATS MORE CRITICAL DEFECTS PER YEAR



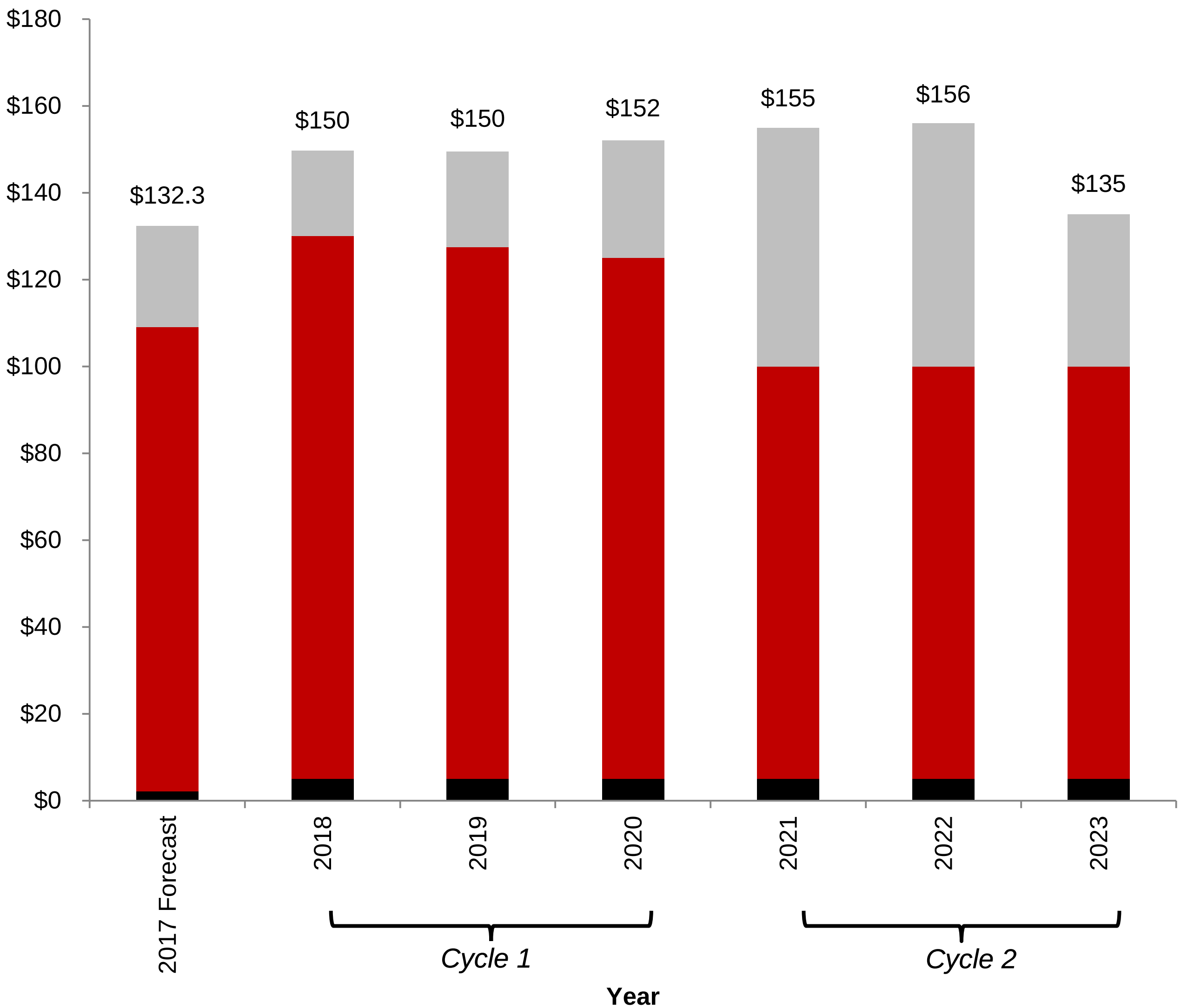
Scope Change Overview

	CURRENT STRATEGY FOCUSES ON CLEARING ~1/10TH OF LINE KMS	NEW STRATEGY TREATS MORE CRITICAL DEFECTS PER YEAR
Scope/Approach	Full Right-of-Way clearing	Defect focused
Cycle/Frequency	10 years	3 years
Cost per unit	$12,000	$3,600
Units per year	10,500 km	34,333 km
Costs per year	$150M	$150M
Defects treated per year	800,000	700,000 to 800,000
Cost per defect	$120	$160
Impact to Reliability	Maintain current reliability	By 2022, we can expect about 40% improvement based on a 10 year average and 58% improvement based on a 2017 year-end projection.
Cost Savings	N/A	$6M to $12M annual saving by 2023 due to reduced trouble calls About $20M reduction starting in 2023 due to on-cycle efficiencies
Environmental Consideration	Infrequent maintenance allowing for incompatible vegetation to establish requiring high intensity clearing	Frequent maintenance allow for a better managed utility forest
Customer Consideration	Infrequent, heavy vegetation management treatment with high aesthetic impact	Frequent, light touch vegetation management treatments with improved aesthetics and customer relations
Safety Consideration	6.5% of the tree utility forest has vegetation grow-in contacts	Less than 1% vegetation grow-in contacts by end of first cycle. Reduced risk of public electrical contact and wildfire

3.5 Million Hour Reduction in Tree-Caused Outage Duration in 2 Cycles



Expected Budget Allocations for First 7 Years of Implementation



WORK PROGRAM WILL REFLECT A NEW ALLOCATION

- Public Safety & reliability Right-of-way work deferred to mid - second cycle
- Cycle Clearing Costs reduced after 1st cycle due to fewer defects
- $5M yearly Optimal Cycle Protocol for sustainment costs and improved analytics
  - Post event analysis, QA/QC, and ongoing maintenance of feeder condition data

Consolidated Business Plan 2018-2023

Board of Directors | December 8, 2017

hydro One

Key Outcomes in this 6 Year Plan include…

Improved Customer Satisfaction	▪ Customer initiatives to improve satisfaction and increase efficiency including:
	  ▪ eBilling will increase customer participation from 8% to 40% by 2022
	  ▪ Web and Bill redesign will increase self-serve transaction from 90,000 to 500,000 by 2019
	▪ Indigenous Relations Initiatives include a new service model for First Nations focused on in-community, face-to-face interactions and enhanced engagement regarding our Distribution and Transmission applications
	▪ Customer bill impacts have been minimized
	[redacted]
	  ▪ Distribution - average of **1.3%** per year or an average of $1.81 per monthly bill

Regulatory Responsiveness	▪ This plan addresses concerns raised by the OEB:
	  ▪ Earlier and more comprehensive customer engagement
	  ▪ Improved investment planning process
	  ▪ Improved work program execution performance

Enhanced Operational Effectiveness	▪ Operations initiatives and outcomes that improve safety, customer satisfaction, reliability and cost:
	  ▪ Replacement of assets and deployment of new technologies reduces the likelihood of failures and associated health, safety and environmental risks
	[redacted]
	  ▪ Reduces Distribution outage duration (SAIDI) by 28% compared to 2017 year end forecast
	  ▪ Using technology to improve operational efficiency and reduce costs
	[redacted]

Financial Performance	[redacted]

[1] See table on Slide 5 for calculation and Risks and Opportunities on Slide 8.

Key Assumptions Underlying the Business Plan

OEB Rate Filings	▪ Distribution 2018-2022 - approved as filed, subject to updates in this plan [redacted] [redacted]
Allowed Return on Equity	▪ Increased from 8.78% in prior plan to 9.00% for 2018-2023
Deferred Tax Asset	[redacted]
Conservation & Demand Management (CDM)	[redacted]
Collective Bargaining	▪ Power Workers Union: 1% existing contract yearly escalation. Agreement expires March 31 2018, Plan escalates by inflation thereafter ▪ Society of Energy Professionals: 0.5% existing contract yearly escalation. Agreement expires March 31 2019, Plan escalates by inflation thereafter
Avista Corporation	[redacted]
Dividend Policy	▪ Plan targets dividend payout in middle of 70%-80% target range
Specifically Excluded from Budget	▪ Future acquisitions ▪ New innovation businesses such as distributed generation ▪ Significant development projects are not included in the plan such as East-West tie and Northwest bulk transmission

[redacted]

[redacted]

[redacted]

[redacted]

Business Plan Opportunities & Risks (Ontario)

	Opportunity/Risk Identification	[1]Net Income Impact (C$ millions) 2018 Budget	[1]Net Income Impact (C$ millions) 2018-23 Annual Impact
Return on Equity	[redacted] Dx: ROE locked at 9.00% until 2021 *100 bps change*	No Impact. ROE set in Business Plan at OEB approved level.	[redacted] Dx : 2021-23 ▪ +/- \$36 – \$39 million annually
Interest Rates	Cost of debt included in revenue requirement, but subject to risk once the revenue envelope is approved *100 bps change*	+/- \$23 million	+/- \$23 – \$40 million annually
Load Forecast	Revenue based on actual demand and consumption may differ from the October 2017 Load Forecast *1 standard deviation*	[redacted] Dx: +/- \$11 million	[redacted] Dx: 2018-23 ▪ +/- \$11 million – \$33 million
Deferred Tax Asset[2]	Risk of losing full shareholder benefit	One-time impairment: [redacted] ▪ Dx: ~(\$370) million	No annual income impact Annual FFO impact: (\$50)–(\$60) million
OEB – Capital	[redacted] 10% of Dx Capital (2018) = \$65M	[redacted]	[redacted]

[1] *1 cent on EPS ~ \$6 million net income*
[2] *Motion to Review & Vary Tx Decision filed in October 2017 seeking full allocation of DTA to shareholder. If unsuccessful, will appeal to higher court with lower probability of success.*

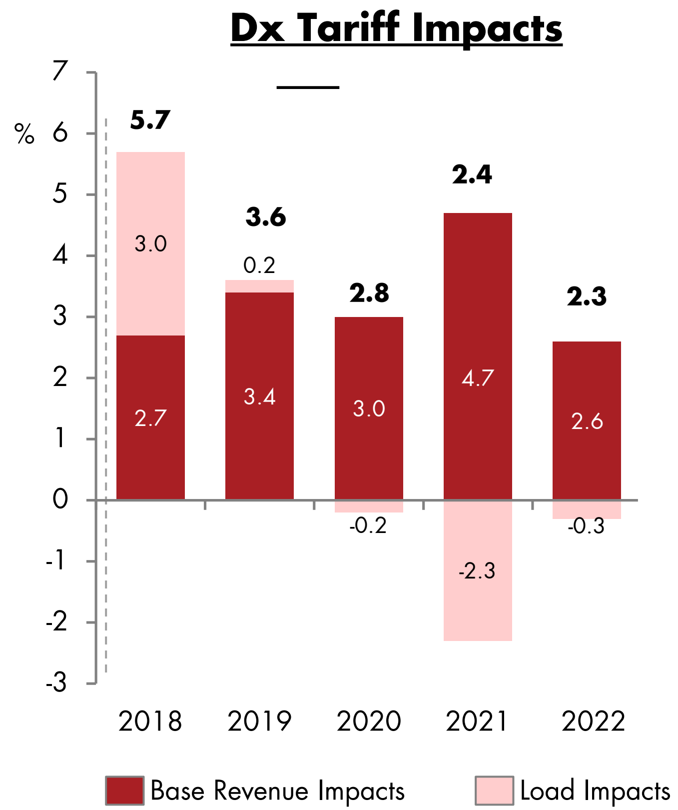
[redacted]

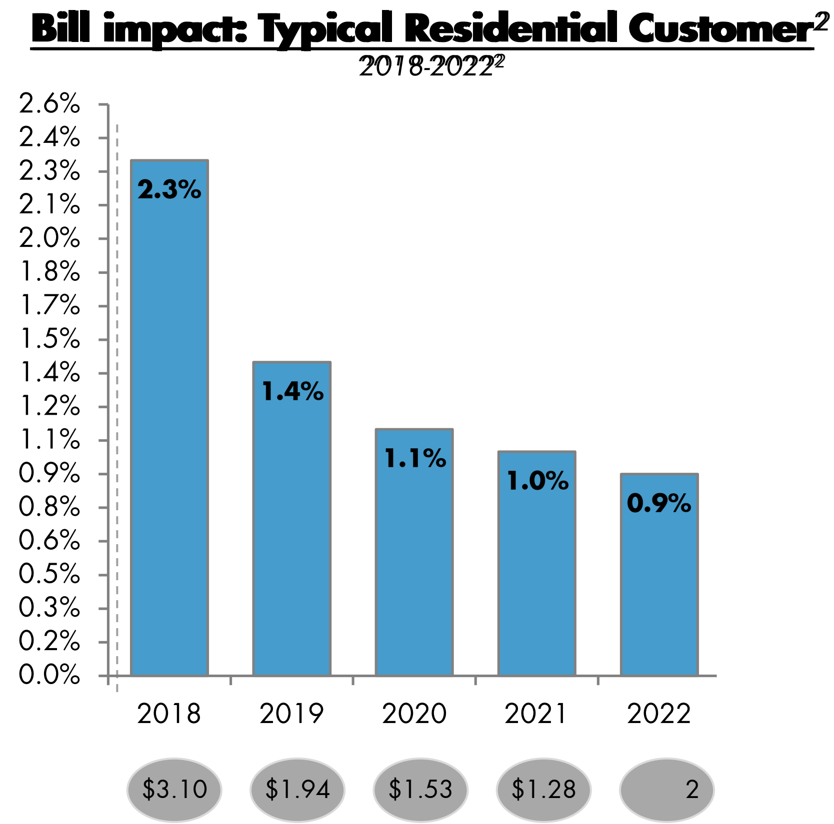
[redacted]

[redacted]

[redacted]

Distribution Tariff and Total Bill Impacts





- **Key Comments:**
  - 2018 Tariff increase largely a result of higher Cost of Capital updates including ROE *[9.00% from 8.78%*]
  - Rate Base Growth throughout the planning period
  - 2021 acquired LDCs incorporated

[1] *Distribution rates only filed with OEB until 2022.*
[2] *An estimated total bill amount before taxes for a typical R1 customer is approximately $135. Fair Hydro Plan impact considered for commodity portion of bill only.*

hydroOne

Strategy

- **Hydro One is transforming to achieve its vision of becoming a best-in-class, customer-centric commercial entity, with a culture of continuous improvement and excellence in execution.**
- **Hydro One's commercial orientation means that the company will:**
  - be focused on customers,
  - demonstrate corporate accountability for performance outcomes,
  - and drive company-wide efficiency and productivity.
- **Hydro One's vision and strategy reflect values that are integral to the well-being of communities:**
  - Safety comes first;
  - Stand for people;
  - Empowered to act;
  - Optimism charges us; and
  - Win as one.
- **The key outcomes that the Company expects from its strategy are as follows:**
  - Improved levels of customer satisfaction;
  - Minimizing the long-term cost of maintaining the reliability of the Transmission and Distribution systems;
  - Maintain top quartile reliability in the Transmission system and continually improve reliability in the Distribution system by mitigating risk arising from asset deterioration;
  - Achieve an injury free workplace and a safe environment for the public;
  - Compliance with all regulatory and reliability standards; and,
  - Responsible environmental stewardship.

Customer Relations

- **Hydro One is a customer centric commercial entity that provides service to its customers that meets their needs and preferences while ensuring that the system continues to deliver safe, reliable energy.**

- **Customer from Tx and Dx were segmented and engaged using a variety of consultation methods**

[redacted]

- **Distribution customers' key preferences**
  - Customers consistently prioritized low rates as the top priority and wanted Hydro One to do its best to limit increases.
  - Reliability was the second most important factor – very low willingness to accept rate increases to attain better reliability.
  - Power quality was a significant factor for large customers.

- **These preferences have guided the development of the investment plan**
- **In-Sourcing of Customer Contact Centre**

Indigenous Relations

- **Hydro One's Indigenous Relations Strategy is to ensure the Company remains committed to developing and maintaining relationships with Indigenous communities that demonstrate mutual respect.**

- **The key goal for Hydro One is to become the primary business partner to Indigenous communities by 2021. The key objectives to meet that goal are:**
  - Become Top of Class: Fully integrate Indigenous relations into each line of business;
  - Become Primary Utility Partner: Create business, technical, knowledge and advocacy partnerships; and,
  - Support Indigenous Leaders: Work with communities by supporting future leaders.

- **Hydro One is actively pursuing a number of initiatives that fit well with the framework:**
  - Successfully offered a new service model to several Ontario First Nation communities that focuses on in-community, face-to-face interactions, to ensure that customers understand and have access to all available programs; and,
  - Implementing the First Nations Conservation Program for communities that have not benefited from the IESO's Aboriginal Conservation Program;
  - Implementing the Affordability Fund to help First Nation customers make their home more energy efficient provided they cannot afford to make energy efficiency improvements, and do not qualify for the Save on Energy Home Assistance Program; and,
  - Development of training for the Executive Leadership on Indigenous Relations.

Regulatory

- **Risks related to obtaining rate orders or other regulatory approvals**
  - Uncertainty regarding, or delays in receiving, approval of major application revenue requirements or capital plans, by the OEB.
  - Risks around regulatory approvals by the OEB for leave to construct applications, applications for mergers or acquisitions and environment approvals

- **Deferred Taxes**
  - As part of the IPO, Hydro One incurred a departure tax of $2.6 billion due to the transition to the Federal taxing authority.
  - Company recorded a deferred tax recovery, representing the fair market value "bump" of its assets, $2.3 billion related to Networks.
  - OEB decision ruled against excluding the tax recovery and 38% is to be shared with Ratepayers – Hydro One is appealing.

- **Integration of Acquired Local Distribution Companies and New Rate Classes**
  - Integration of acquired LDCs to be complete in 2021

- **Rate Setting Approach and Business Implications**
  - Dx rates for 2018 will be set using a rebasing approach and rates for 2019 to 2022 will be set on a formulaic basis. Proposing a similar application for Transmission.
  - Risks on OM&A borne by the shareholder and the company loses the ability to adjust for load and ROE over the period.
  - Have proposed updating load forecast and ROE in 2021 to coincide with the integration of Acquired Utilities.
  - This adds risk and opportunity for the Company and must be carefully managed.

- **Capital In-Service Variance Account**
  - Dx application proposed a CISVA; [redacted]. The features of a CISVA include:
    - Tracks variances between in-service additions and amount included in OEB approved rates in each individual year;
    - Revenue requirement associated with any under spending to be accumulated and returned to customers at end of the five-year term; and,
    - Account will be asymmetrical; over spending of these amounts is not recoverable.

Productivity

- **Quantifiable and sustainable improvements embedded in the work program and or cost centers:**
  - More effective procurement programs, including investments in new processes and tools;
  - Reductions in administrative expenditures through improved processes, tools and optimization of internal staff skills;
  - Rationalization of Fleet size, cost and related spending;
  - Rationalization of IT spending;
  - Improved field efficiency through improved work planning and analytics; and,
  - Development of analytical measures to enable tracking of outcomes and better leveraging of existing spend.
- **Robust governance structure ensures productivity savings reported accurately**

[redacted]

hydroOne

[redacted]

[redacted]

Investment Plan – Total OM&A

[redacted]

[redacted]

Highlights

- **The plan addresses condition assessments, preventative and corrective maintenance, including increasing environmental and regulatory compliance requirements.**
- Dx OM&A plan is $2.8 billion over five years
- [redacted]
- Vegetation Management and Planned Outage Reductions account for 80% of the overall distribution SAIDI reductions

The plan incorporates OEB and Customer Feedback:

- Reflects customer priorities for cost, safety and reliability
- Continues to optimize the life of the existing assets by balancing operational risk, cost and value delivered to customers

Forecasted costs for the core Dx Investment Plan are consistent with the figures filed with the OEB

- Incorporates the new vegetation management program (Optimal Cycle Protocol) that is expected to result in improved unit costs and long-term efficiency as well as improved reliability and customer satisfaction

[redacted]

Common Corporate Costs

- **Majority of costs allocated to Transmission and Distribution (89%).**
- **A significant portion of these costs get capitalized (49%).**
- **The remaining 11% of costs get allocated to Telecom, Remotes, Other Subs and Shareholder.**

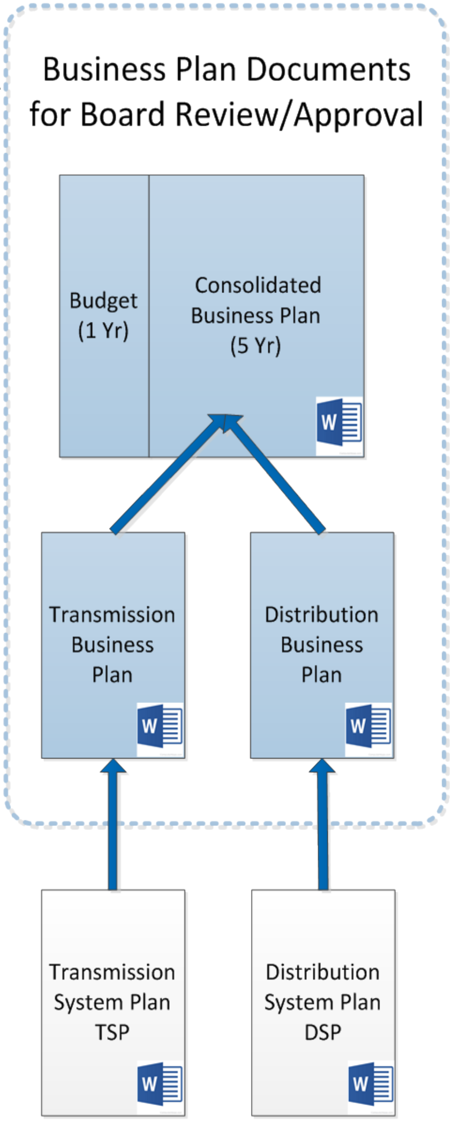
Corporate Common Cost $M	2017F	2018	2019	2020	2021	2022	2023	CAGR
Corporate Management	$ 12	$ 14	$ 14	$ 14	$ 15	$ 15	$ 15	3.9%
General Counsel & Regulatory Affairs	$ 35	$ 41	$ 39	$ 38	$ 38	$ 40	$ 41	2.6%
Operations	$ 113	$ 108	$ 108	$ 106	$ 107	$ 108	$ 108	-0.8%
Customer and Corporate Relations	$ 40	$ 43	$ 44	$ 45	$ 47	$ 47	$ 47	3.1%
Human Resources	$ 18	$ 22	$ 21	$ 21	$ 22	$ 22	$ 22	3.7%
Strategy	$ 13	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	-3.3%
Finance	$ 43	$ 48	$ 48	$ 49	$ 50	$ 50	$ 51	2.8%
Information Solutions Division	$ 21	$ 19	$ 19	$ 17	$ 18	$ 18	$ 18	-2.7%
Bad Debt	$ 18	$ 19	$ 19	$ 18	$ 18	$ 18	$ 18	-0.3%
Total	**$ 313**	**$ 323**	**$ 321**	**$ 320**	**$ 325**	**$ 329**	**$ 331**	**0.9%**

	OM&A	Capital
Transmission Portion	16.4%	30.3%
Distribution Portion	23.9%	18.8%
Other Allocated	10.7%	

Appendix

Business Plan Diagram

- **Consolidated Business Plan** – fundamental document outlining the company's plans for the 2018-2023 period.
- **Budget** – this document, which integrates closely with the Consolidated Business Plan, lays out the specifics of expenditures for the 2018 calendar year.
- **Transmission Business Plan** – Plan for the 2018-2023 period that focuses on the Transmission side of the business. It is fully expected that this will be filed with the OEB as part of our April 2018 Tx rate filing.
- **Distribution Business Plan** – Plan for the 2018-2023 period that focuses on the Distribution side of the business. Either by interrogatory or by motion, it is fully expected that this could be called into evidence as part of our previous March 2017 Dx rate filing with the OEB.
- **Transmission System Plan** – TSP to be filed as part of the April 2018 Tx filing. This is a document explaining the many factors, processes and outcomes that comprise our investment plan.
- **Distribution System Plan** – the DSP was filed as part of our Dx application in March 2017. This has not been altered.



[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

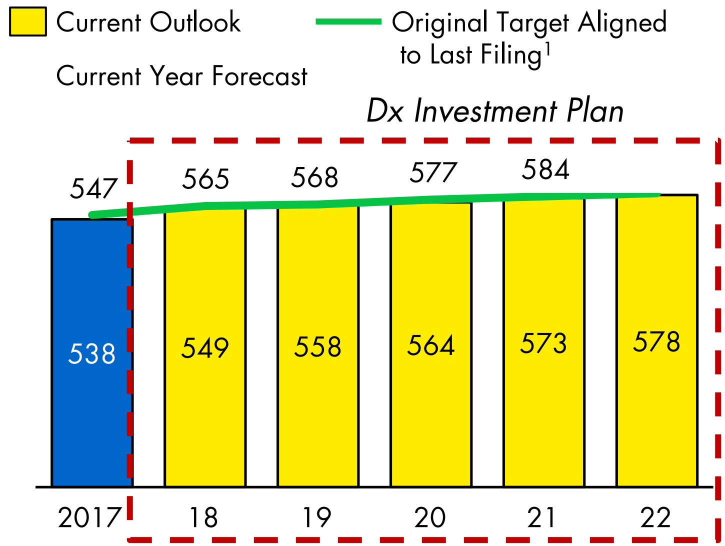
hydroOne

Investment Plan – Dx OM&A

Dx OM&A is $2.8 Billion over five years, representing an annual 1.3% Growth Rate

Work Program OM&A Trajectory 2018-2022

$ Millions (Does not include corporate common costs)



	Total OM&A $ M, 2018-22	OM&A Growth %, 2018-22	OM&A Growth %, 2019-22
Original Target	$2,885	1.1%	1.3%
Draft Plan	$2,823	1.3%	1.2%
Change	($17)	0.2%	(0.1%)

Highlights

Dx OM&A Plan is $2.8 Billion over five years

Forecasted costs for the core Dx Investment Plan are consistent with the figures filed with the OEB

- Redirection opportunities have been identified, but not embedded in the plan, to introduce a shortened and targeted vegetation management program that is expected to result in long-term productivity savings as well as improved reliability and community relations.

Common corporate investments have been updated consistent with the Tx Investment Plan.

We minimized the customer rate impact of the plan through productivity commitments

- Includes $142 Million of embedded productivity savings related to the core Dx business, identified in the previous plan
- Includes $61 Million of common IT savings

1. Original target based on previous investment plan filed as part of the 2018-22 Dx Rate Application
2. Figures exclude Acquired LDCs

hydro One

School Energy Coalition Interrogatory # 5

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

None

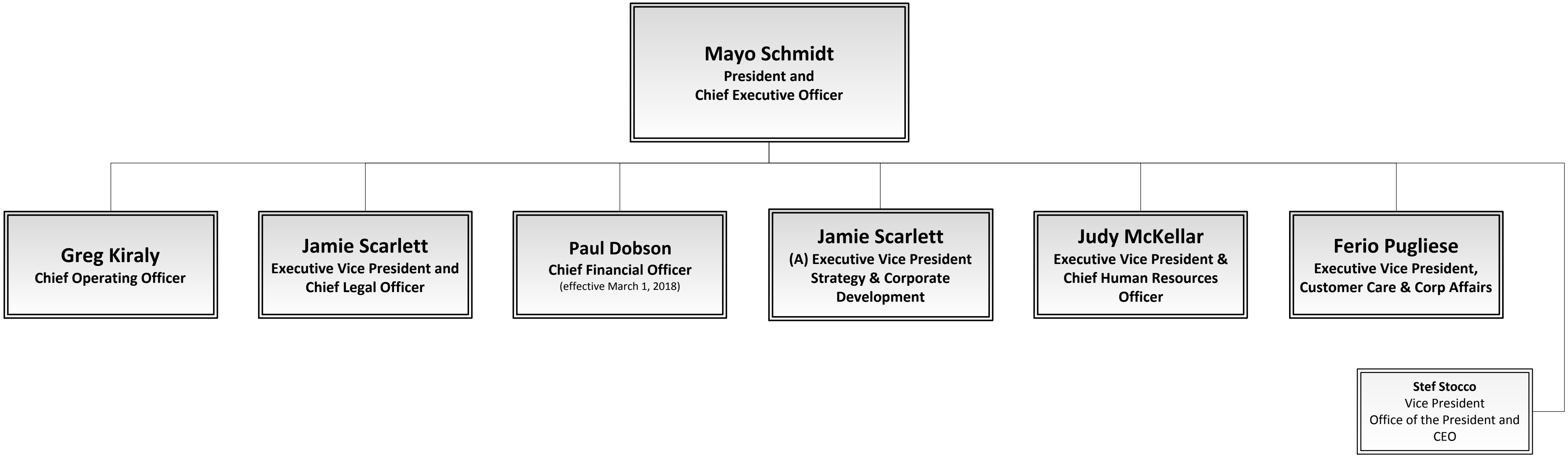
Interrogatory:

Please provide a full Hydro One Networks Inc. organizational chart.

Response:

Please see attached organizational charts for direct reports to the President and CEO to the Director level.

President and Chief Executive Officer



Operations

- **Greg Kiraly**
  Chief Operating Officer
  - **Paul Madore**
    Pres. & CEO, Hydro One Telecom
  - **Bing Young**
    Vice President
    Engineering
  - **Andrew Spencer**
    Vice President
    Transmission & Stations
  - **Brad Bowness**
    Vice President
    Distribution
  - **Darlene Bradley**
    Vice Presidet
    Planning
  - **Robe Berardi**
    VP
    Shared Services
  - **Martin Huang**
    VP
    System Operations
  - **Kraemer Coulter**
    Managing Director
    Remote Communities

Distribution

- **Brad Bowness**
  Vice President
  Distribution
  - **Alex Turpin**
    Director
    Distribution Lines
  - **Tom Jackson**
    Director
    Forestry
  - **David Price**
    Superintendent
    Forestry Work
    Management
  - **Scott Vicary**
    Director
    Distribution Lines Work
    Management
  - **Kelly Kingsley**
    Director
    Q & A Business Support

System Operations

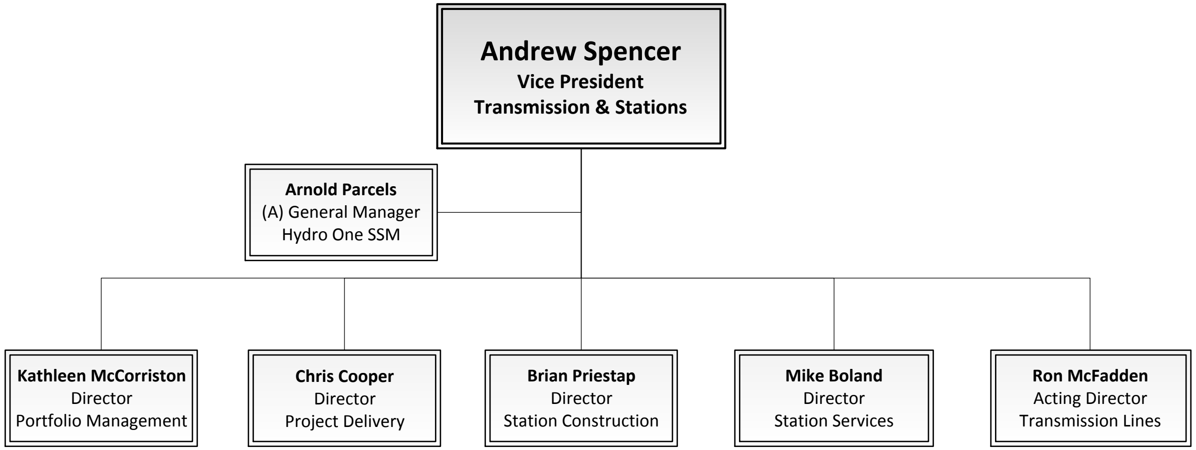
Martin Huang
Vice President
System Operations

- **Glenn Benish**
  Director
  AMI System Operations Support
- **Godfrey Holder**
  Director
  Business Strategy & Program Management
- **Tom Irvine**
  Director
  Network Operating
- **Peter Mitskos**
  Director
  Advanced Metering Infrastructure Operations
- **Derek Roles**
  Director
  Emergency Preparedness & Restoration

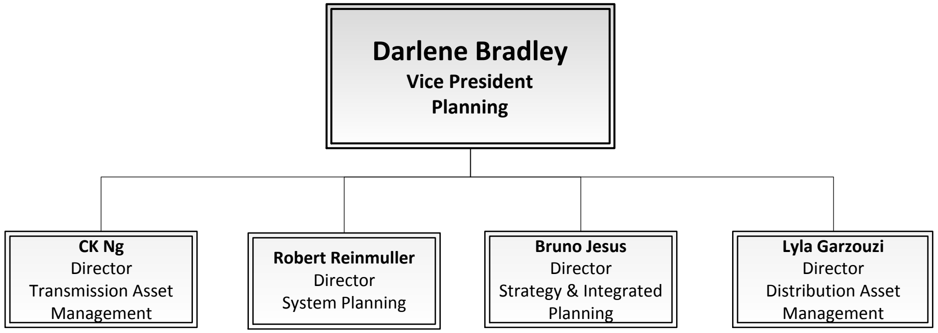
Engineering Services

- **Bing Young**, Vice President, Engineering
  - **Ayesha Sabouba**, Director, Transmission & Stations Engineering
    - **Donna Jablonsky**, Senior Manager, Tx & Dx Stations Engineering
    - **Tim MacKay**, Senior Manager, Telecom Engineering
    - **Kai Wong**, Senior Manager, Protection Control & Metering Engineering
    - **Ibrahim Hathout**, Senior Manager, Transmission Engineering
    - **Joe Kim**, Senior Manager, EESNT
  - **Jawed Atcha**, Senior Manager, Engineering Production Support
  - **Frank Lupo**, Senior Manager, Transmission Technical Services
  - **Prasath Suppiah**, Senior Manager, Distribution Technical Services
  - **Steve Hodder (RI)**, Manager, Quality Assurance & Continuous Improvement

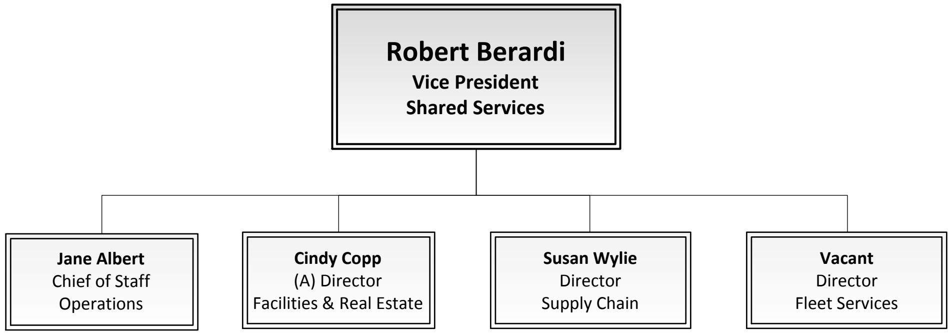
Transmission & Stations



Planning


Darlene Bradley
Vice President
Planning
CK Ng
Director
Transmission Asset Management
Robert Reinmuller
Director
System Planning
Bruno Jesus
Director
Strategy & Integrated Planning
Lyla Garzouzi
Director
Distribution Asset Management

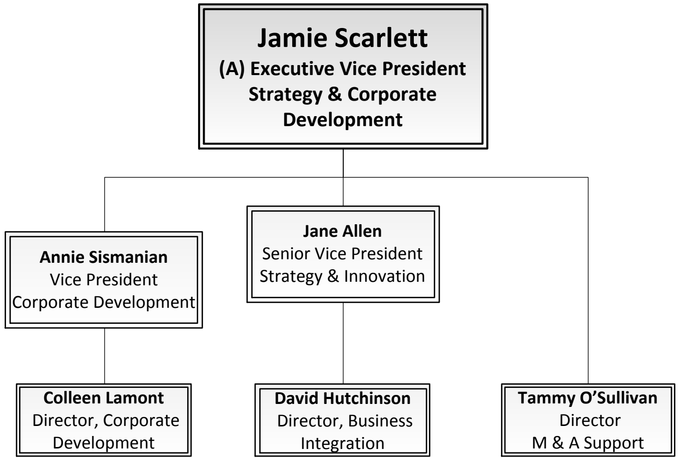
Shared Services



General Counsel

- **Jamie Scarlett**
  Executive Vice President and Chief Legal Officer
  - **Michael Engelberg**
    Assistant General Counsel
    - **Vacant**
      Counsel for First Nations & Metis Matters
    - **Monica Caceres**
      Senior Legal Counsel
    - **Dana McDonald**
      Senior Legal Counsel
    - **Ryan Robert**
      Senior Legal Counsel
  - **Cassidy McFarlane**
    Assistant General Counsel
    - **Ann Yi**
      Senior Legal Counsel
    - **Sanjeev Dhawan**
      Senior Legal Counsel
  - **Adele Pantusa**
    Assistant General Counsel and Chief Records Officer
    - **Naomi Martin**
      Senior Legal Counsel
    - **Ara Arzumanian**
      Senior Legal Counsel
    - **David Wyrstiuk**
      Senior Legal Counsel
  - **Maureen Wareham**
    Corporate Secretary and Chief Ethics Officer
    - **Jane Camara**
      Assistant Corp. Secretary

Strategy and Corporate Development



Human Resources / Health, Safety & Environment

- **Judy McKellar**
  Executive Vice President & Chief Human Resources Officer
  - **Saylor Millitz-Lee**
    Vice President
    Total Rewards
    - **Sabrin Lila**
      Director
      Comp & HR Analytics
    - **Vivan Yoanidis (4)**
      Interim Director
      Recruitment
    - **Vivian Yoanidis**
      Director
      Diversity & Inclusion
    - **Sylvia Kocsondy**
      Director, Learning & Development
  - **Greg Lane**
    Head of Enterprise Change & HR Transformation
  - **Jason Fitzsimmons**
    Vice President
    Employee & Labour Relations
    - **Nadine O'Neill**
      Director
      Labour Relations
    - **Susan Sutton**
      Director
      HR Support Centre
    - **Keith McDonell**
      Director
      HR Projects
    - **Erin Jonasson**
      Director
      HR Operations
    - **Farah Alexis**
      Director
      HR Corp Groups
  - **Lisa Williamson**
    Vice President
    Health, Safety & Environment
    - **Elise Croll**
      Director
      Environmental Services
    - **Mike Ferguson**
      Director
      Health & Safety

Customer Care & Corporate Affairs

- **Ferio Pugliese**
  Executive Vice President, Customer Care & Corp Affairs
  - **Jay Armitage**
    Director
    Communications
  - **Daniel Levitan**
    Director
    External Relations
  - **Warren Lister**
    Vice President
    Customer Service
    - **Giuliana Rossini**
      Director
      Affordability Fund
    - **Spencer Gill**
      Director, Key Account
      Management
    - **Robert Globocki**
      Director
      Customer Care
    - **Imran Merali**
      Director
      Customer Care
    - **Danny Relich**
      Director
      Meter to Bill
  - **Derek Chum**
    Vice President
    Indigenous Relations
  - **Cindy-Lynn Steele**
    Vice President
    Market Solutions
    - **Whitney Brhelle**
      Director
      Market Solutions
    - **Thomas Semler**
      Director, Strategy and
      Conservation CDM

Finance

- **Chris Lopez**
  Senior Vice President
  Finance
  - **Samir Chevlada**
    Director, Corporate
    Accounting & Reporting
  - **Ryan Lee**
    Director, Management
    Accounting & Reporting
  - **Vacant**
    Director
    Business Planning &
    Finance Support
  - **Helen Poletes**
    Director
    Data Governance
  - **Nancy Tran**
    Vice President
    Tax
  - **Ali Suleman**
    Vice President &
    Treasurer

Information Solutions Division (ISD)

Colin Penny
Senior Vice President and Chief Information Officer

- **Godfrey Desira**
  Project Director
  Back-up Control Centre Project
- **J.J. Blais**
  Director
  Corporate Projects
- **Lincoln Frost-Hunt**
  Director
  Enterprise IT
  EIT
- **Andy Whittington**
  Director
  Power Systems IT
  PSIT
- **Rick Haier**
  Chief Security Officer
- **Peter Ruppert**
  Director
  Business Solutions

Regulatory Affairs

Frank D'Andrea
Vice President, Regulatory & Chief Risk Officer

- **Allan Cowan** — Director, Strategic Advisor
- **Jeff Smith** — Director, Business Performance (Rotation Out)
- **Ian Malpass** — Director, Regulatory Initiatives Compliance & Support
- **Jody McEachran** — Major Applications
- **Henry Andre** — Director, Pricing
- **Joanne Richardson** — Director, Major Projects & Partnership

School Energy Coalition Interrogatory # 6

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
None

Interrogatory:
Please provide summaries of all internal audit reports conducted since 2014, related to any aspect that directly or indirectly relates to Hydro One's distribution business, their findings, recommendations, and the status of any actions that are to be taken.

Response:
Please see filed MS Excel I-03-SEC-006.

School Energy Coalition Interrogatory # 7

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-01-03, Attachment A-B

Interrogatory:

With respect to Hydro One's Internal Audit Report, *Auditor General Report 2016 Follow-up*:

a) The report states that management commits to Task 49 (p.9) which is an independent third-party review of its DSP (p.12). Is the AESI review located at Exhibit B1-2-1, the third-party review referenced in Task 49? If not, please provide a copy of the independent third-party review of Hydro One's DSP.
b) Please provide a similar table to Appendix B showing all tasks that had been completed before September 30, 2016 (i.e. all Tasks that came out of the response to the Auditor General's Report and are not listed in Appendix B).
c) Please provide an updated status on all outstanding Tasks required to be completed listed in Appendix B, and the date they were completed.
d) If Tasks 46 and 48 are now complete, please provide results of the reviews/analysis.
e) [A-3-1, Attachment 4, p. 10] Hydro One says "Internal Audit validated 39 activities as completed in Sept 2016. As a follow-up, at the end of March 2017, a request was made to Internal Audit to validate evidence on the remaining items completed over the timeframe of Oct 2016 to March 2017. This will take place before the end of 2017." If Hydro One's Internal Audit has completed this work to date, please provide a copy. If not, please undertake to provide a copy when the information becomes available.

Response:

a) Yes, the AESI review is the third party review referenced in Task 49.

b) Please see Table 1 in Appendix A for all tasks completed by September 30, 2016.

c) Please see Attachment 6 to Exhibit I-3-SEC-8 (Internal Audit Report: Auditor General Follow-up 2017) for an updated status on tasks listed in Appendix B.

Witness: KIRALY Gregory

d) Task 46 and 48 are complete.

Task 46: As noted in Attachment 1, the results of the assessment of past maintenance expenditures and activities, with a focus on critical factors and contributors to the distribution reliability measures have been incorporated into the development of the DSP and specific investment justifications.

Task 48: The identified benchmarking studies have been included in the DSP.

- Distribution Unit Cost Benchmarking Study: Pole Replacement and Substation Refurbishment included in DSP – Ex B1-1-1, Section 1.6, Attachment 1 (page 2000 of 2930)
- Hydro One Vegetation Management Study 2016 included in DSP – Ex B1-1-1, Section 1.6, Attachment 2 (page 2035 of 2930)

e) Please see Attachment 6 to Exhibit I-3-SEC-8.

Appendix A

Table 1: AG Recommendation Task Numbers – Tasks completed as of September 30, 2016

AG Recommendation	Task #	Management Commitments
1	1	Conduct assessments on poor performing single circuit transmission lines consistent with the Customer Delivery Point Performance Standard.
	2	Continue to analyze outage data to identify reliability issues and identify investments to improve customer reliability in accordance with the OEB’s Customer Delivery Point Performance Standard (CDPPS).
	5	Implement Planning-Stage work-bundling strategy to combine planned maintenance to reduce planned outages, reducing the risk of delivery point interruptions.
	7	Continue to report on System Reliability through the CEA
2	8	Identify Preventive Maintenance backlog
	9	Perform analysis to confirm "completed" orders are appropriately documented
	10	Document existing Preventive Maintenance strategy and process.
3	12	Provide clear explanation regarding our transformers and breakers replacement strategy, selection process and execution methodology as part of the 2017/18 Tx Rate Application.
	13	Provide information specific to key assets replaced in 2015, 2016 or planned to be replaced, and reasons for deferrals.
	14	Provide information specific to key assets planned to be replaced in 2017 and 2018 with justifications and possible deferrals as part of the 2017/18 Tx Rate Application.
4	15	Engage a third party expert to review the transformer fleet health assessment.
5	16	Re-evaluate the augmentation of the AA tool to include the additional risk factors (i.e. Environmental/H&S, Obsolescence)
	19	Define accountabilities for change control for all asset classes.
	20	Identify all Tx data included in Asset Analytics and implement project to populate these elements
	21	Implement strategy to populate absent legacy asset data
	22	Replace Asset Analytics Google earth view to provide a more accurate view of the Tx system
	23	Address backlog of Transmission Lines GIS updates.
6	25	Re-prioritize resources to address actions deferred from previous internal audits through a data remediation project

AG Recommendation	Task #	Management Commitments
7	28	Continue Planning-stage work bundling to allow integrated outage scheduling and integrated work execution and minimize outages.
	29	Conduct benchmarking and best practice studies with other North American transmitters for reliability and cost improvements, consistent with OEB direction
8	31	Develop and implement a new comprehensive security program which will apply to all electronic devices, including the hardening of deployed devices.
9	33	Establish an Investment Plan for the 2017-2022 period which identifies projects to improve reliability.
	34	Monitor project completions as part of monthly reporting process and incorporate remote monitoring and control into investment scopes.
	35	Update asset portfolio documents for vegetation management to include reliability management of Large Distribution Account customer feeders.
	36	Establish Vegetation Management prioritization matrix to increased emphasis on reliability to provide execution teams more direction. Introduce more granular work accomplishment reporting as part of monthly reporting cycle.
	37	Develop strategies for cost-effective investments to improve reliability, including increased line and distribution station renewal; relocating assets to road allowances to improve access and facilitate fault-finding; enable control room visibility and controllability of devices, and prioritizing vegetation management programs to focus on reliability to large commercial/industrial customers.
10	38	Introduce an eight-year vegetation management cycle over the longer term.
	40	Prioritize vegetation management on feeders with more frequent tree-related outages.
	41	Conduct annual vegetation management program review to identify issues and action plans for improvement.
11	43	Enable the interface between the Distribution GIS system and Asset Analytics to make recent design changes visible.
12	44	Continue to maximize asset life expectancy and optimize work efficiency for pole assets based on operations, maintenance and conditions under which the asset is used.
	45	Continue to base asset replacement decisions based on condition, not age.
13	47	Participate in benchmarking studies, as directed by OEB, to support its approaches to investment, maintenance and sustainment activities to be included in the next distribution rate application.
15	51	Review Forecasting Model for predicting Transformer failures

Witness: KIRALY Gregory

AG Recommendation	Task #	Management Commitments
	53	Develop a plan to standardize Distribution Transformers and implement a rationalization strategy to reduce the number of types of transformers
	54	Review plans for further rationalize the number of types of Transmission transformers
	55	Conduct detailed review of Tx Spares models & compliment needs
	59	Quantify Savings from moving from (current) 14 Standards to fewer Standards
	60	Develop a strategy to reduce number of Tx spare transformers in inventory from 44 to 28 over next 10 years
	61	Develop a Strategy and Process to determine DS Spare Transformer scrapping and purchase requirements
16	65	Provide PQ information to Tx-connected customers, including estimates of frequency and duration of potentially disruptive voltage sag events tailored to the customer's specific connection point.
	66	Perform detailed analysis of PQ data to improve estimation of the frequency, duration and magnitude of potential events that could have an adverse effect on its equipment and processes.
	67	Provide PQ reports to identified customers
17	69	Review contingency and escalation allowances used in Capital project estimates and establish an internal guideline in line with industry benchmarks
	70	Implement a project closure process for larger projects to ensure work is completed as planned, project estimates are compared against actuals, all variances are explained and learnings are incorporated into future projects; Include originally approved budget and in-service dates
	71	Implement a process to provide a yearly summary of completed projects to compare project estimates to final project costs and determine "success rate" over the next 10 years

School Energy Coalition Interrogatory # 8

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

Auditor General of Ontario 2017 Annual Report, Vol 2, Chapter 1, Section 1.06, http://www.auditor.on.ca/en/content/annualreports/arreports/en17/v2_106en17.pdf

Interrogatory:

With respect to the Auditor General of Ontario's Follow-Up Report to its 2015 Annual Report on Hydro One:

a) Please provide copies of all correspondence and information exchanged between the Auditor General and Hydro One regarding the 2015 Annual Report follow up.

b) The Auditor General of Ontario notes with respect to Recommendations 11, 12, 13, 14, 15, 16, 17 and 18, Hydro One did not provide requested information, details, and/or supporting documents. For each recommendation, please provide the information, details and/or supporting documents requested by the Auditor General of Ontario.

Response:

a) Please see Attachments 1-5 for letters Hydro One exchanged with the Auditor General of Ontario.

b) For clarity, there are 17 recommendations from the Auditor General, not 18. Please see Attachment 6 for the Internal Audit – Auditor General Report Follow-up 2017, which has been redacted for items specific to Hydro One's transmission business.

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Daniel Levitan
Director, External Relations

hydro one

April 26, 2017

Bonnie Lysyk
Auditor General of Ontario
Box 105, 15th Floor
20 Dundas Street West
Toronto, ON
M5G 2C2

Dear Ms Lysyk,

On behalf of Hydro One, I wish to thank you for the opportunity to follow up on your *2015 Annual Report,* and the related section 3.6 – *Hydro One: Management of Electricity Transmission and Distribution Assets.* As you may know, since becoming a private company in 2015, it has been a priority of Hydro One's executive leadership team to change the way Hydro One does business. We are transforming Hydro One into an industry leading customer-centric organization; advocating for our customers and communities; and have applied great rigor to ensure that at every level, we are driving productivity and operational efficiency throughout the Company.

While we are no longer bound by many of the rules governing a Crown Corporation, it is our pleasure to provide you with an update to our March 23rd, 2016 appearance before yourself and the Standing Committee on Public Accounts.

The *2015 Annual Report* highlighted 17 recommendation areas. Hydro One has committed to completing 71 remedial activities, of which:

- A total of 66 are now completed,
- Two (2) activities will be completed by May 2017, and
- The remaining 3 items will be completed by the end of 2017.

These recommendations have been grouped into 12 functional areas, with the appropriate recommendations noted in the subject headers along with a high-level brief on the activities completed and status below.

1. Transmission & Distribution Systems Reliability Performance [Rec: 1, 9] (Complete ✓)

Recommendations included setting multi-year targets and timetables for reducing the frequency and duration of power outages and establishing cost-effective action plans and strategies to improve reliability performance. Also, to more thoroughly analyze outage data on both our transmission single and multi-circuit systems.

Activities Completed:

- To improve our ability to more accurately measure the effect of system investment on transmission reliability, Hydro One has supplemented its existing analysis with an additional model to quantify reliability risk which provides a directional indication of the effect of system investment on future transmission system reliability. This was introduced in the latest transmission rate filing application.

- Organizational changes were implemented in 2016 to establish a Planning Analytics team that works closely with the asset planners. This has enabled better performance analysis and integration into the Investment Planning process.

- Multi-year transmission and distribution reliability targets are in development and will be set by the end of April 2017.

- Transmission Strategies have been implemented to combine planned maintenance activities into a single work-stream to enable the reduction of planned outages, creating outage and work bundling opportunities in the execution phase, hence reducing the risk of customer delivery point interruptions.

- Annual iterative processes are now in place to conduct detailed analyses on transmission customer delivery point performance and determine investment options for outliers. This enables integration into future business plans through an annual review of the interruption data to identify the main issues that are negatively impacting the system's reliability.

- Annually, a comprehensive analysis of the 5- and 10-year historic transmission reliability performance is executed. Within this process, opportunities identified within Hydro One's control are the primary focus; these are further investigated for remediation investment options in accordance with the Customer Delivery Point Performance Standard (CDPPS). Communication to affected customers on plans for outlier improvement activities occurred for the first time in 2016 and is now an annual iteration.

- A high-level analysis of the 5-year historic transmission reliability performance vs maintenance program spend was completed, identifying opportunities for shifting of program funds to asset classes which contribute significant duration minutes to overall reliability performance.

- A comprehensive review of the outstanding deficiency reports (i.e. Defect Notifications, DRs) across all the asset hierarchies: T&D Stations & Lines (and Forestry program) has been completed, ensuring that no open DRs of a critical rating are unaddressed. This action ensures that no know deficiencies are overlooked and mitigates the impact equipment failures can have on planned outages.

- The Distribution System Plan (DSP) for the 2017-2022 timeframe has been developed and included in the recent rate filing submission. Strategic updates based on customer consultation feedback were incorporated in late 2016 along with adjusted investments in programs to improve reliability on specific under-performing assets.

- Distribution Strategies implemented include: Increasing Programs for line renewal and distribution station renewal; moving the location of rebuilt lines from off-road line sections to road allowances to improve access and facilitate fault-finding; enabling control room visibility and controllability of many devices, and prioritizing vegetation management programs to focus on reliability to large commercial/industrial customers.

- Distribution investment prioritization matrix has been updated to include greater weighting on reliability and more priority categories to give field crews more direction for work throughout and better visibility to important feeders. This includes off ramps in the program (forestry) to cut lower priority work if funding constraints are encountered.

- Monitoring of distribution work accomplishments on a more granular level (including project completions) are in place and reported monthly. Station refurbishments include monitoring and control in the scope of work and Line switch remote controllability is monitored annually to demonstrate number of controllable points.

2. Transmission and Distribution Systems Spend Related to Reliability [Rec 7, 13] (Complete ✓)

Recommendations included conducting an assessment of past maintenance expenditures and activities to determine what changes and improvements can be made to more effectively focus efforts on the critical factors that improve system reliability and to conduct benchmarking cost assessments related to reliability.

Activities Completed:

- Transmission: Several activities were completed in the areas of reviewing of maintenance expenditures, reliability performance, enabling work bundling opportunities and deficiency reports. All of these activities are listed above under item 1.

- Transmission: Cost and reliability performance benchmarking was completed by Navigant and submitted as part of the 2017-2018 rate filing application.

- Distribution: An assessment of past maintenance expenditures and activities was completed, with a focus on critical factors and contributors to the distribution reliability measure. Strategic updates to distribution programs and projects, based on customer consultation feedback, were undertaken in Q3 2016, are supported by standardized Investment Summary Documents (ISDs) which are included in the Distribution System Plan.

- Distribution: Hydro One participated in benchmarking studies, to support its approaches to the investment, maintenance and sustainment activities included in the recently filed distribution rate application. Studies included vegetation management, pole replacement program, and station refurbishment program.

- Distribution: In 2016 Hydro One undertook an independent third-party review of the Distribution System Plan, providing unit cost validation for forestry, pole replacement and station refurbishment programs.

3. Transmission and Distribution Assets in Service Beyond Their Expected Life [Rec 3, 4, 12] (Complete ✓)

Recommendations included ensuring that its applications for rate increases to the Ontario Energy Board provide accurate information on its asset replacement activities, including whether it actually replaced assets in poor condition that were cited in previous applications and whether the same assets are being resubmitted. In addition, the findings have recommended targeting assets that have exceeded their planned useful service life and have the highest risk of failure and to re-assess its practice of replacing assets that are rated as being in good condition.

Activities Completed:

Context Clarification: As defined in our latest rate filing evidence, the expected service life is the average time in years that an asset can be expected to operate under normal system conditions. It does not imply the asset will need immediate replacement beyond this period of time. Hydro One operates a fleet of assets that are beyond expected service life. However, Hydro One's asset management objective is to maintain asset performance while minimizing full life cycle costs. This is accomplished through proper maintenance and timely replacement which are detailed in our application. This approach benefits ratepayers by minimizing rate increases.

- The Auditor General made a recommendation that Hydro One should be replacing assets based on their age rather than their condition. Hydro One employs investment planning processes, systems and trained planning Engineers to make prudent renewal plans based on multiple risk factors. The Company's experience is that our expected service life for various assets is appropriate given the operations, maintenance and conditions under which they are used. Hydro One does not replace assets that, while old, are in good working condition. The aim is to maximize the life expectancy of an asset and optimize work efficiency in order to derive the most value from our investments.

- The expected service life values for key asset classes was reviewed, found to be valid and in line with other utilities. Replacement rates and pacing of investments are reflected in both the transmission and distribution rate applications and aligned with the customer consultation needs and preferences.

- Transformers and breakers replacement strategies, selection process and execution methodology are clearly outlined in our rate filing evidence, providing the rationale behind each replacement.

- Transmission: A third party industrial expert, Electric Power Research Institute (EPRI), reviewed our transformer fleet health (condition) assessment. This supports our fleet health assessment methodology to verify that rate increases accurately reflect asset replacement activities.

Context Clarification: The Auditor General made conclusions regarding the deferral or delay in replacing transmission transformers. This conclusion was solely based on asset condition information but without the benefit of the full information that Hydro One uses in determining asset replacement. Asset Condition is not the sole consideration in determining the need to replace an asset. These replacement decisions take into account many factors; conversely, assets in good condition may need replacement based on other factors such as environmental, health and safety, inadequate capacity and customer needs and preferences, while assets that are deteriorated may be deprioritized due to their having a less material impact on the system.

- Transmission: All transformers selected for replacement in 2017-2018 are supported by detailed assessments and engineering reports. Replacement is anchored by an overarching strategy document. Individual transformer replacement decisions are based on Asset Risk Assessment process as outlined in rate filing evidence.

4. Information Provided to OEB in Rate Applications [Rec 6] (Complete ✓)

Recommendations included ensuring that Hydro One's applications to the Ontario Energy Board for rate increases include accurate assessments of the condition of its assets.

Activities Completed:

Context Clarification: Hydro One endeavors to ensure all data submitted to the OEB for rate setting purposes accurately reflects its forward test year plans. In making this statement, the Auditor General appeared to have focused on investments that appeared in successive applications. In practice, investments are sometimes delayed due to work execution delays or other factors including changes in priority due to changing circumstances since the last rate application.

- To address this concern Hydro One has provided evidence supporting the 2017-2018 capital spending plans. These plans are based on the best information available at the time of filing the application. Hydro One is also prepared to explain variations from its previous plans and/or OEB approved spending amounts, compared to actual work completed. In addition, data quality improvement activities explained under item 5 below.

5. Asset Analytics System – Data Remediation [Rec 5, 11] (Mostly Complete ☑)

Recommendations included enhancing the Asset Analytics system to include information on all key factors that affect asset investment decisions; review and adjust current weighting assigned to risk factors to more accurately reflect their impact of asset condition and risk of failure; and make changes to procedures so that updates to Hydro One's data are complete, timely, reliable and accurate to ensure the information can support our asset replacement decision making process.

Activities Completed:

Context Clarification: The purpose of Asset Analytics is to provide asset planners with convenient access to asset data and assess emerging risk factors in an efficient manner. Decisions to replace assets are made by the asset planners in part based on Asset Analytics output and also based on many factors fully described in our rate filing evidence. Asset Analytics is one tool to aid in decision making, but it is not the only factor considered.

A data remediation project was established in 2015 to address the data quality, population levels, processes and functionality issues related to the Asset Analytics tool. The focus was on data used in the AA algorithms.

Significant data and functionality improvements for Asset Analytics were completed over 2015-2016, with key activities as follows:

- Metrics: Dashboards for population levels, missing data reports and effectiveness of new assets completeness have been established for all of the Transmission and Distribution asset hierarchies.
- Data: Transmission Stations data has been increased from 35% to 85%, Transmission Lines from 50% to 70%, with new assets consistently close to 100% population.
- Data: Distribution Stations data has been increased from 35% to 60%, Distribution Lines data is a current focus, starting at 69%, with a plan to get to 85% by year end. This work is in progress.
- GIS: A backlog of more than two years of TLGIS updates has been completed; and the distribution MADX translator has been fixed. With these fixes in place, transmission and distribution Planners can now see updates using the AA tool to view an accurate transmission and distribution network configuration in a GIS environment.
- Characteristics: ~30-40% of asset characteristics were discarded through workshops conducted to confirm "needs" tied to business needs. This eliminates many data fields that were being collected but not required. All characteristic data has been assigned a priority rating, high priority data population is showing great improvement.
- Data Templates: More than 250 data templates were revised, for the first time since "go-live" in 2008, enabling better data quality entry and providing clear direction to staff in LOB population roles.
- Legacy population strategies were employed; utilizing default values, data audits/comparisons to other systems, matching of records on key attributes, and some manual entry. All of these contributed to improving the quality and population level of the transmission hierarchies.
- In progress: Distribution data remediation continues, focusing on key activities such as asset counts across multiple systems (i.e. poles, pole-top transformers in GIS, SAP differ at present), development of Lines metrics dashboard and process fixes, targeted completion for main activities is by the end of 2017.

6. **Prioritization of the Distribution System Vegetation Management Program [Rec 10] (Complete ✓)**

Recommendations included shortening the vegetation management cycle to be more cost-effective and in line with other similar local distribution companies and to change the way we prioritize lines that need clearing.

Activities Completed:

- A comprehensive review of the vegetation management program was undertaken and the prioritization model was improved to better support decision-making through the increase in reliability weighting on the risk matrix so that it becomes a major driver of prioritization. The program is reviewed annually.

- The vegetation management program has been adjusted to get feeders to an eight-year cycle over the longer term and in 2016, a new On-Cycle Maintenance Program was introduced. It is not economically feasible to get to a shorter (4-year) cycle as the Auditor General has recommended. Re-focusing work crew deployment and flexible locational work is also being implemented to enable improvement in unreliable areas.

7. **Preventive Maintenance Orders Backlog on Transmission Equipment [Rec 2] (Complete ✓)**

Recommendations included establishing a timetable that eliminates a growing preventive maintenance backlog and improved oversight of preventive maintenance programs to ensure it is completed as required and on time.

Activities Completed:

- Backlog: The identified backlog was partially due to a one-time generation of 2,440 PCB oil sampling orders (consisting of 12,500 equipment) to facilitate execution efficiency. These orders are not expected to be completed until 2021. These oil sample testing orders are to ascertain PCB level in oil filled equipment older than 1985. The result of these testing will determine if the PCB level is >50 ppm, which will help Hydro One determining whether a retro-filling or replacement is needed to comply with federal regulation to phase out PCB by 2025.

- Oversight: There are clearly outline accountabilities, authorities and processes around preventive maintenance orders generation, prioritization, redirection, scheduling, cancellation and deferral. This includes an over-release strategy (8% buffer above and beyond available resources) for maintenance orders to minimize outages. No critical preventive maintenance orders can be deferred without approval from Asset Management.

-

8. Use of Smart Meters Capabilities to Improve Response to Power Outages [Rec 14] (Mostly Complete ☑)

Recommendations included improving customer service and lowering repair costs relating to power outages through more accurate and timely dispatches of its repair crews and to develop a plan and timetable for using our existing smart meter capability to pinpoint the location of customers with power outages.

Activities Completed:

- The Advanced Metering Infrastructure for Operations and the Advanced Metering Infrastructure for Analytics project charters have been reviewed and approved for implementation. This will allow for integration of the smart meter outage data to the outage management system, enable monitoring of asset loading information based on the network topology and proactively allow monitoring of our assets to avoid premature and possibly unplanned asset failures due to overloaded equipment.

- Our pilot technology has continued to deliver value. As a result, in addition to being able to ping meters to determine whether customers have power at their premises and avoid re-dispatching crews for further repair work, it will deliver further value by consolidating multiple meters without power and showing the scope of a power outage to the control room operators.

- *In progress*. Requirements and scope have been solidified and vendors chosen to do the work. Estimated completion and implementation is the end of 2017.

9. Electronic Devices Security Framework [Rec 8] (Complete ✓)

Recommendations included developing a comprehensive security framework to cover all electronic devices ensuring a robust and high level of security for the transmission system to mitigate the risk of service disruptions due to sabotage, vandalism, software viruses, or unauthorized changes to device software or controls.

Activities Completed:

- Hydro One has completed the development of a comprehensive security framework. This framework is called the Hydro One Security Code of Practice which includes the Security Policy and Security Operating Standards for the organization. The Code of Practice was completed and implemented as part of the NERC CIP v5 Standards.

10. **Transmission and Distribution Spare Transformers Fleet [Rec 15] (Complete ✓)**

Recommendations included improving the spares forecasting model; review and adjust spares inventory levels; develop plans to standardize in-service transformers and set targets and timelines for achieving savings.

Activities Completed:

Note: All activities are applicable to both the Transmission and Distribution power transformer spares.

- The Markov Model used to predict spare requirements have been updated; this model utilizes industry proven strategic spares risk analysis methodology to determine the appropriate quantity of operating spares.

- Spares Strategies. Transmission and Distribution Spares strategies have been approved. The strategies address key issues such as (i) reducing existing inventory, (ii) reinforcing first-in-first-out policy, and (iii) establish spare transformers shelf life to trigger mandatory deployment.

- Standardization. Transmission power transformer fleet was reviewed for further standards incorporation and determined that the existing 14 procurement standards are sufficient, limited value in adopting additional standards. Distribution power transformer fleet was reviewed and a refined set of procurement standards was established, reducing from 60 standards down to 45. Quantification of savings and timelines for achieving same has been established and documented.

- A comprehensive review and documentation of power transformer inventory at the Central Maintenance Shop (CMS) was completed and plans are in place to ensure required compliment totals are accurate and maintained. Asset data (including Level 1, 2, 3 spares information) has been updated in the system of record (i.e. SAP) to enable better tracking of available spares and their deployment status. Reviews will be completed annually.

hydro one

11. Power Quality (PQ) Meters Data Use, Helping Customers Avoid Disruptions [Rec 16] (Complete ✓)

Recommendations included minimizing the number and impact of power quality events for its large customers through proactively using the data collected by its power meters to help assess the frequency and location of power quality events on its transmission and distribution systems, thereby improving the reliability.

Activities Completed:

- Hydro One has completed system studies to estimate the magnitude, frequency and duration of power quality voltage sag events. The results of these system studies provide an indication of the number, severity and duration of voltage sag events that a customer may experience and should be able to withstand. These studies are used by Hydro One to identify and undertake initiatives to minimize power quality impacts to customers and customers will be able to use these studies to inform their decisions regarding investments to improve their resilience.

- Hydro One is working with our customers to enable their revenue meters to also serve as PQ meters. This will allow for more effective assessment of PQ events and customer impact. We have also offered the services of 3rd party experts to assess customers' facilities and recommend measures to increase their resilience to minor to moderate PQ events.

12. Management Oversight Processes over Capital Project Costs [Rec 17] (Mostly Complete ☑)

Recommendations included conducting benchmarking to assess capital construction project costs; adherence to industry-normal contingency and escalation allowances; to improve management reporting and oversight of project costs showing actual project costs and completion dates compared to estimates.

Activities Completed:

- A Total Cost Benchmarking study (Navigant) was completed noting a number of benchmarks for project management performance. The internal work breakdown structure has been refined to enable a more efficient, consistent and accurate cost collection process for capturing project actual costs and comparisons.

- Contingency and escalation allowances have been reviewed and redefined. Escalation rates are now in line and consistent with our corporate business plan and we have implemented a quantitative project risk management methodology. In addition, a formalized project closure report process (including all project stakeholders) has been implemented to analyze the project plan and the effectiveness of its execution.

- >*In progress*. Hydro One is currently working to develop relationships with peer Canadian utilities to develop a consistent approach to benchmarking capital project work with an early focus on transmission lines projects and with a subsequent focus to be on substation projects.

I trust that you will find this information helpful as you draft the follow-up reports volume of the 2017 Annual Report. The response to your report is representative of a herculean effort within Hydro One as a part of our transformation from Crown Corporation to a world-class electricity services organization.

Thank you again for allowing us the opportunity to follow up on your 2015 report and for taking the time to review our progress in the intervening years.

Regards,

Daniel Levitan
Director, External Relations

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Daniel Levitan
Director, Government Relations and Public Affairs

Monday August 14, 2017

Gigi Yip
Office of the Auditor General of Ontario
20 Dundas Street W, Suite 1530
Toronto, Ontario
M5G 2C2

Hello Gigi,

Thank you again for providing us with an opportunity to review elements pertaining to Hydro One in the Auditor General's upcoming Annual Report. We have reviewed the two sections and have determined that we have no further commentary to provide at this time.

Enclosed you will find the five hard copies that you had provided to us. As per instructions, no copies were made.

Of course, please feel free to call me should you wish to discuss further.

Regards,

Daniel Levitan
Director, Government Relations and Public Affairs
Hydro One

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Daniel Levitan
Director, Government Relations and Public Affairs

Tuesday May 23, 2017

Gigi Yip
Office of the Auditor General of Ontario
20 Dundas Street W, Suite 1530
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Hello Gigi,

Our detailed letter to the Office of the Auditor General, as with our letter to the Committee on Public Accounts on the same topic was a good faith effort to inform the two entities of the activities raised in the Auditor General's 2015 Annual Report and in Hydro One's subsequent appearance before the Committee.

While we understand your office's intent to further inform the upcoming report, we need to be clear that our letter response was provided as a courtesy and that Hydro One will not be providing any further detail on the matter. Following the passage of Bill 91, *An Act to implement Budget measures and to enact and amend various Acts*, 2015, Hydro One is no longer an agency of the Crown and must act accordingly. Save for providing information for the assembly of consolidated financial statements, Hydro One is no longer subject to inquiries by the Auditor General (Schedule 3, Auditor General Act).

Of course, please feel free to call me should you wish to discuss further.

Regards,

Daniel Levitan
Director, Government Relations and Public Affairs
Hydro One

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James Scarlett
Executive Vice President and
Chief Legal Officer

hydro One

September 6, 2017

Ms. Bonnie Lysyk
Auditor General of Ontario
20 Dundas St West
Suite 1530
Toronto, ON
M5G 2C2

Dear Ms Lysyk,

Thank you again for allowing us advanced review of our section in your upcoming Annual Report. As we have discussed with your office, while we appreciate the opportunity, we have no comments to provide on the findings contained in the Report.

Regarding your request for a letter of representation, I note that, as Hydro One is no longer participating in the audit process, nor is it currently being audited, it is not appropriate for management of Hydro One to sign an audit representation letter. Accordingly, we respectfully decline the request to sign the letter you had sent over, or any similar document.

Regards,

James Scarlett
EVP and Chief Legal Officer
Hydro One Limited

Office of the Auditor General of Ontario
Bureau de la vérificatrice générale de l'Ontario

July 26, 2017

Mr. Daniel Levitan
Director, External Relations
Hydro One Networks Inc.
483 Bay Street
South Tower, 8th Floor Reception
Toronto, ON
M5G 2P5

Dear Mr. Levitan:

Enclosed are two copies of the preliminary draft report of our follow-up on the 2015 audit of *Hydro One: Management of Electricity Transmission and Distribution Assets* as well as two copies of the preliminary draft report of our follow-up on the December 2016 Standing Committee on Public Accounts report on *Hydro One: Management of Electricity Transmission and Distribution Assets*. These follow-up reports are based primarily on the information provided to us by you and your staff this year, and supplemental information provided by your staff in response to our questions and review.

Copies of the draft reports are part of our working papers and must therefore be kept strictly confidential and are not to be copied. Please keep track to whom copies are provided and return them to us after the reports have been finalized. As well, please provide us with an email indicating who has received a copy of the draft follow-up report as soon as possible.

In order to adhere to our Follow-up Report preparation and publishing schedule, I would appreciate it if you could please provide me with any comments on the contents of the draft reports by August 9, 2017. If you would like to discuss the content of the reports or have any questions, please contact me at 416-212-7094.

To meet new Canadian auditing standards, we are requesting deputy ministers and assistant deputy ministers, as well as organization CEOs and vice presidents or equivalents, to sign a management representation letter. I have enclosed a representation letter dated August 16, 2017 to you. Upon finalization of these follow-up reports, I will request that the signed letter be provided to me.

Sincerely,

Gigi

Gigi Yip
Director

Encl.
cc. (without Attachment)
Mr. Mayo Schmidt, President and CEO, Hydro One Limited and Hydro One Inc.
Ms. Rosemarie T. Leclair, Chair and CEO, Ontario Energy Board

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INTERNAL AUDIT REPORT

Auditor General Report Follow-up 2017

To:

Greg Kiraly
Chief Operating Officer

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Chris Lopez	Senior Vice President, Finance
Darlene Bradley	Vice President, Planning
Andrew Spencer	Vice President, Transmission and Stations
Bruno Jesus	Director, Strategy and Integrated Planning
Chong Kiat Ng	Director, Transmission Asset Management
Lyla Garzouzi	Director, Distribution Asset Management
Kathleen McCorriston	Director, Project Management
Additional Recipients	Email Distribution List

Final Report Issued: November 28, 2017
Draft Report Issued: October 17, 2017
Report Number: 2017-19

Lead Auditor: William Chan
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

In November 2016, Internal Audit completed a follow-up audit[1] of the control environment to address the recommendations made in the 2015 Auditor General's Report. Based on Internal Audit's 2016 follow-up audit, 31 committed management actions remained outstanding. There were 8 management actions that had target completion dates beyond September 30, 2016 that were not formally assessed as part of the 2016 follow-up and were identified in that report as "work in progress". These actions, along with the 23 committed management action items found to be partially or substantially complete in the 2016 follow-up, were assessed as part of a follow-up we recently performed. The management and resolution of the action items outlined in this report is important to the company as it can have a significant impact on corporate reputation, as well as the overall efficiency of work performed to maintain our assets in ensuring a safe, reliable, and cost effective electricity supply for our customers.

Objective and Scope:

The objective of this audit was to perform a follow-up review of the outstanding committed management actions associated with the follow-up audit report completed in 2016, and to provide the status of Hydro One's actions to address the recommendations outlined in the 2015 Auditor General's Report. Our work involved a review of the status of these actions and the degree to which they address the issues (design effectiveness).

Our work included:

- A review of the available evidence supporting the status of the 31 committed management actions (that were not previously verified as complete) in Hydro One's response to the 2015 Auditor General's Report, to provide assurance that a process is in place to address all of the recommendations. As agreed with management, the evidence provided by a cutoff date of August 31, 2017 formed the basis of this assessment.[2]
- Updating our understanding of the key controls that provide assurance relative to the audit objective.
- Interviewing and discussion with accountable management, staff and stakeholders regarding completeness of committed actions.
- Briefing management on any gaps throughout the review.
- Recommending improvements, where appropriate.

The scope of our work did *not* include an assessment of the management commitments assessed as complete in the 2016 follow-up review, or the propriety of the Auditor General's recommendations.

Success Factors:

We noted that the following success factors were in place:

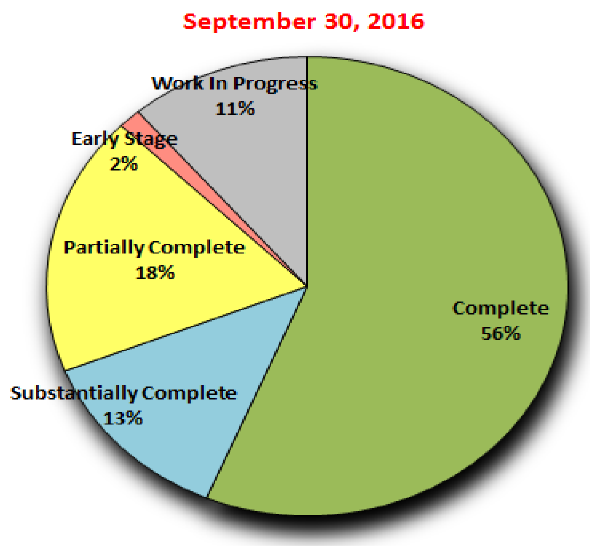
- A single accountable Director was assigned to coordinate with the lines of business to establish, assign, prioritize, and schedule the required actionable tasks.
- A mechanism to track and report on all completed and outstanding actions was established.

[1] Auditor General Report Follow-up 2016 Report Number: 2016-18
[2] Additional evidence was taken into account during the preliminary observations meeting on October 18, 2017.

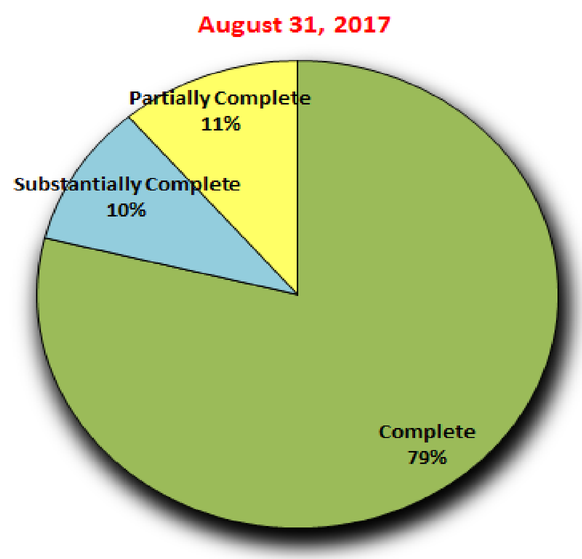
- All actions were assigned a target completion date by the respective line of business Directors with management status update comments provided at milestone points of March 31, 2017 and June 15, 2017 for most of the actions.
- There were 2 actions that had target completion dates beyond August 31, 2017. We reviewed evidence provided by management and have observed that progress is being made on these actions.

Summary of Observations:

The charts shown below provide an illustrative comparison of the summary status of Hydro One's committed actions as determined during the 2016 and 2017 follow-up audits.



Management Committed Actions	Actions Complete	Substantially Complete	Partially Complete	Early Stage	Work In Progress
71	40	9	13	1	8



Management Committed Actions	Actions Complete	Substantially Complete	Partially Complete	Early Stage	Work In Progress
71	56	7	8	0	0

The following table shows the status of the 31 actions which we assessed as at the conclusion of this review, with further details outlined in Appendix A, along with definitions of the assessment levels.

Auditor General Recommendations	Outstanding Management Committed Actions	Actions Complete	Substantially Complete	Partially Complete	Early Stage	Work In Progress
17	**31**	**16**	**7**	**8**	**0**	**0**

* Definitions of the degree of completeness can be found in the table at the end of this Executive Summary.

On June 15, 2017, management reset the target completion dates for all outstanding actions. Of the 31 actions due on or before August 31st, 2017, management reported 19 actions as complete.

The key observations we made are intended to facilitate the completion of the remaining management actions as originally committed in response to the Auditor General's Report recommendations:

- An initiative is presently in place to establish data governance and guidelines to improve data quality within the organization; however the evidence continues to show a lack of focus on distribution asset data quality.
- In some cases, management has been considering changes to the previously committed management actions (due to evolving business needs/directions). Currently there is no formal process and approval mechanism to manage the revision of the original management commitments.

We have shared our observations with management. The objective of those meetings was not to elicit any management actions; rather to communicate the outcome of our review. Management demonstrated that it is committed to continue its efforts to complete all of the actions in support of Hydro One's commitments included in the 2015 Auditor General's report.

We would like to thank the management and staff in Strategy and Integrated Planning, Transmission Asset Management, Distribution Asset Management, and Project Management for their assistance during this review.

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	**Complete**	All actions fully address Hydro One's response in the Auditor General's Report.
	Substantially Complete	Action lacking full completion i.e., implementation plan, rollout, approvals or communication.
	Partially Complete	Some actions have been taken, however insufficient completeness for Internal Audit to assess control design effectiveness.
	Early Stage	Little or no action taken. Insufficient completeness for Internal Audit to assess control design effectiveness.
	Work In Progress	Tasks that were planned for completion past the audit timeframe for the 2016 review - i.e. later than September 30, 2016. The design effectiveness on the management action was not assessed as part of the follow-up audit.

Control Design Effectiveness	**Effective**	The actions or controls designed, fully address Hydro One's commitments in the Auditor General's Report.
	Substantially Effective	The actions or controls designed mostly (but do not fully) address the Hydro One's commitments in the Auditor General's Report.
	Partially Effective	The review of control designs indicate that only some risks are mitigated.
	Ineffective	The control design is ineffective. Control improvements needed to address the commitments

Management Response:

Bruno Jesus, Director, Strategy and Integrated Planning

Management agrees with Internal Audit's assessment of our actions to address the recommendations in the 2015 Auditor General's report and we continue to track the status of the remaining actions to their completion.

[redacted]

[3] The assessment criteria on the completion and control design effectiveness of the action items are included in Appendix C.
[4] Transmission Reliability Metric: Transmission System Average Interruption Duration Index.(TxSAIDI)
[5] Insufficient completeness for Internal Audit to assess control design effectiveness.

AG Recommendation 5: Information Systems on Asset Condition incl. Asset Analytics

- Enhance its Asset Analytics system to include information on all key factors that affect asset investment decisions, including those related to technological/manufacturer obsolescence, known defects, environmental impact and health and safety.
- Review and adjust current weighting assigned to risk factors in Asset Analytics to more accurately reflect their impact of asset condition and risk of failure.
- Make changes to its Asset Analytics system and procedures so that updates to its data are complete, timely and accurate.
- Conduct a comprehensive review of the data quality in Asset Analytics to update any incomplete or erroneous information on its assets and to ensure the information can support its asset replacement decision making process.
- Investigate why known deficiencies in the reliability of the Asset Analytics system, such as those found two years earlier by internal audits, have not been corrected by management in a timely manner.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
16	Re-visit and evaluate the augmentation of the Asset Analytics tool to include the additional risk factors (i.e. Environmental/Health & Safety, Obsolescence)	Partially Complete	N/A
17	Risk Algorithms Review: Conduct a review of the risk factors algorithms and adjust current weightings as necessary to better support the asset replacement decision-making process.	Complete	Effective
18	Improve the data collection, population and monitoring process for SAP data utilized in the Asset Analytics tool.	Partially Complete	N/A
21	Implementation of strategies for the population of absent legacy data (~1 million data fields will be addressed through default populations, derivation, validation, etc.).	Partially Complete	N/A
24	Development of data quality assessments and data audits for all Transmission asset classes.	Partially Complete	N/A

Observations:

- Management has a plan in place to address additional risk factors requirements for Asset Analytics over a 3 year period between 2018-2020. (Task 16)
- Risk factors algorithms have been reviewed and adjusted to better support the decision-making process. (Task 17)
- The data remediation effort has not adequately addressed distribution data completeness. (Task 18, 21)
- There is a lack of sustainable approach over the long term to manage data completeness and data quality. (Task 21)
- The implementation timelines, project scope, recommended targets on data quality and timeliness, roles, and accountabilities have not been adequately stakeholdered during the time of the audit (early September 2017) in order for us to evaluate the effectiveness of the control design. (Tasks 21, 24)

[redacted]

[redacted]

AG Recommendation 9: Distribution System Reliability

- Establish more ambitious performance goals, targets and benchmarks for system performance.
- Develop short- and long-term strategies for new and enhanced activities and cost-effective investments that will improve its overall reliability record.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
32	Based on the approved funding in the investment plan, DxAM needs to establish multi-year reliability targets and implement the new initiatives (programs) to specifically target improving distribution reliability performance.	Complete	Effective
33, 35, 37	***Requirement to Complete as stated in the 2016 Auditor General follow-up audit:*** *Establish the appropriate funding level with senior management and the Board prior to 2017 Distribution Rate Filing.*	Complete	Effective

Observations:

- Management has established year over year targets 2018-2023 for Distribution SAIDI. Management's commitment was not prescriptive as to which reliability metric(s) would be involved. Ideally, management would establish year over year targets for all metrics that it submits to the OEB, we find that management has met this committed action for Distribution. (Tasks 33,35,37)
- Since Hydro One is committed to reporting SAIDI and SAIFI to the OEB (according to Electricity Reporting & Record Keeping Requirements, May 2016), we suggest that management also establish multi-year targets for SAIFI. (Tasks 33,35,37)
- The Hydro One Business Plan was approved by the Board on December 2, 2016. The Business Plan is the basis for the 2018-2022 Distribution Rate Application, EB-2017-0049 which included new strategies to the vegetation management program, lines sustainment initiatives program, and the worse performing feeders program to drive improvements on overall distribution reliability. (Task 32)

AG Recommendation 10: Prioritization of Vegetation Management Work on the Distribution System

- Shorten its current 9.5-year vegetation-management cycle to a more cost-effective cycle of less than four years, in line with other similar local distribution companies.
- Change the way it prioritizes lines that need clearing so that lines with more frequent tree-related outages are given higher priority and work crews are dispatched sooner.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
39	Review vegetation-management program and improve prioritization model to support decision-making. Quarterly review of progress in 2016; Annual review in Q3/4 2016.	Complete	Effective

Observations:

- Evidence was provided on the stakeholdering of the vegetation-management program and improvements on the prioritization model. A program accomplishment review was conducted in January 2017.

AG Recommendation 11: Quality of Data for Distribution Assets

- Ensure that management decisions on replacing distribution system assets are made using reliable and complete information, Hydro One should take the actions needed to ensure its Asset Analytics system provides timely, reliable, accurate and complete information on the condition of assets.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
42	Following the remediation of the Transmission data, Planning will enable a project to focus on the Distribution data. However, due to resource constraints, both of these initiatives are not able to be implemented simultaneously within the business.	Partially Complete	N/A

Observations:

- Based on the evidence gathered on the distribution data (DS, DL) remediation efforts, this project is currently running on an ad-hoc basis with a lack of an implementation schedule nor the establishment of the data completeness and accuracy targets.

AG Recommendation 13: Spending to Maintain Distribution System Reliability

- Conduct an assessment of its past maintenance expenditures and activities to determine how to focus efforts on more critical factors that affect the system.
- Benchmark cost assessments with other similar local distribution companies (LDCs) in Ontario and Canada, and consider implementing the best practices of the leading cost-effective LDCs.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
46	Assessment of past maintenance expenditures and activities, with a focus on critical factors and contributors to the distribution reliability measure.	Complete	Effective
48	Undertake a third-party review of its distribution system plan that will provide unit cost validation for forestry, pole replacement and station refurbishment.	Complete	Effective
49	Hydro One's Distribution System Plan is under development and we will be having an independent third party review of such in 2016.	Complete	Effective

Observations:

- The asset planning documents for vegetation management, distribution station refurbishment, and pole replacement were completed with the submission of the Distribution System Plan as part of the Distribution Rate Filing.
- Evidence was provided to address the third party review of the Distribution System Plan for the Distribution Rate Filing.

AG Recommendation 14: Smart Meter Capabilities to Improve Response to Power Outages

- Lower its repair costs and improve customer service relating to power outages through more accurate and timely dispatches of its repair crews, Hydro One should develop a plan and timetable for using its existing smart meter capability to pinpoint the location of customers with power outages.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
50	The Advanced Metering Infrastructure for Operations and the Advanced Metering Infrastructure for Analytics project charters under the larger ADS project have been reviewed and approved for implementation. This will allow for integration of the smart meter outage data to the outage management system.	Substantially Complete	Substantially Effective

Observations:

- The first phase of the Advanced Metering Infrastructure for Operations project has been completed. This established real-time situational awareness outages based on signals received from customer smart meters. It provides an alarm screen showing second by second meter outages and restoration along with a geographic view.
- Operational decisions are made based on the number of outage incidents that were screened that had successful meter pings from the new smart metering tool. A mechanism has been developed to track and monitor the amount of savings from crew dispatch to investigate these incidents.
- As stipulated in the original Advanced Metering Infrastructure for Operations project charter, the full value of this work will be realized through both consistent and systematic use of the meter interrogation capability to analyze power and equipment outage scenarios, and the integration with ORMS, as presently planned for future implementation.
- The integration (Phase 2) of smart meter capabilities with ORMS[6] is still work in progress. To this end, we've reviewed evidence to show that the scope is currently being defined along with the development of an implementation plan.

[6] ORMS: Outage Response Management System.

AG Recommendation 15: Operating Spares Management of Transmission and Distribution Transformers

- Improve the forecasting model it uses for predicting transformer failures.
- Maintain its inventory levels of spare transformers in accordance with the forecasts.
- Develop a plan to standardize in-service transformers as much as possible.
- Set targets and timelines for achieving savings from better managing both spare and in-service transformers.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
52, 53, 56, 57, 60, 61, 64	***Requirement to Complete as stated in the 2016 Auditor General follow-up audit:*** *Complete management's commitment to review the existing draft strategies and policies on operating spares, make appropriate updates, stakeholder them and formally issue them for use.*	Complete	Effective

Observations:

- Evidence shows that Asset Management has reviewed, stakeholdered, and approved the existing draft strategies and policies (for transmission and distribution operating spare transformer requirement and management) formally issue them for use.

AG Recommendation 17: Oversight on Capital Project Costs

- Use industry benchmarks to assess the reasonableness of capital construction project costs, and whether using internal services and work crews is more economical that contracting out capital projects.
- Use and adhere to contingency and escalation allowances that are more in line with industry norms for capital construction projects.
- Improve its management reporting and oversight of project costs by regularly producing reports that show actual project costs and actual completion dates compared to original project cost estimates, cost allowances used, original approved costs, subsequent approvals for cost increases, and planned completion dates.
- Regularly analyze its success in preparing project estimates by comparing them with final project costs.

Task #	Task Description (Original Management Commitments)	Assessment of Completion	Assessment of Control Design Effectiveness
68	As part of project closure process, compare our internal construction project costs to industry benchmarks of contracting out similar capital work.	Partially Complete	N/A

Observations:

- The benchmarking process was documented in an email response to a request from Internal Audit during the time of the 2017 AG follow-up audit. Management states that there is a general understanding of this benchmarking process among staff, however no evidence was provided to show this process is repeatable and has been stakeholdered with staff involved in the process.
- Evidence shows a comparison was done between "historical actual costs" vs "external estimates". The comparison should also include external actual costs since the final contracted price may vary, especially if it is not a fixed price contract or if there are substantial scope changes involved.
- At the time of the follow-up audit, 2 committed sub-action items remain incomplete.

Establish benchmarking process to compare Internal vs. External costs based on recent Canadian study. Begin with Lines project types.	Oct 2017	On Track
Compare AR 22869 - Q11S/Q12S Actuals vs. costs from historical H1 line projects	*Oct 2017	On Track

- Management is committed to meeting the target completion date of December 31, 2017 on this action item.

Appendix B

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	**Complete**	Evidence exists to demonstrate that the committed actions are complete. All actions fully address Hydro One's response in the Auditor General's Report.
	Substantially Complete	Most actions and control designs are complete, however they are lacking any of the following elements: implementation plan, rollout, approvals, communication, awareness to stakeholders.
	Partially Complete	Actions have been taken on some tasks, however the controls still require further design, stakeholdering, and implementation. Insufficient completeness for Internal Audit to assess control design effectiveness.
	Early Stage	Little to no progress has been made in actions and control designs. Insufficient completeness for Internal Audit to assess control design effectiveness.
	Work In Progress	Tasks that were planned for completion past the audit timeframe for the 2016 review - i.e. later than September 30, 2016. The design effectiveness on the management action was not assessed as part of the follow-up audit.
Control Design Effectiveness	**Effective**	The actions or controls designed fully address the commitments within Hydro One's response in the Auditor General's Report.
	Substantially Effective	The actions or controls designed mostly address the commitments within Hydro One's response in the Auditor General's Report.
	Partially Effective	The review of control designs indicate that only some risks are mitigated.
	Ineffective	The control design is ineffective. Better controls are available to address the commitments within Hydro One's response in the Auditor General's Report.

School Energy Coalition Interrogatory # 9

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

Report of the Standing Committee on Public Accounts – Hydro One Management of Electricity Transmission and Distribution Assets

http://www.ontla.on.ca/committee-proceedings/committee-reports/files_pdf/41_2_PAC_Hydro%20One%20Management_08122016_EN.pdf

Interrogatory:

For each recommendation that in whole or in part relates to Hydro One's distribution business, please provide the information requested by the committee.

Response:

See Attachment 1 which has been redacted for information unrelated to this Application.

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www.HydroOne.com

Daniel Levitan
Director, External Relations

April 26, 2017

Katch Koch
Clerk of the Committee
Standing Committee on Public Accounts
99 Wellesley Street West
Toronto, ON
M7A 1A2

Dear Mr Koch,

On behalf of Hydro One, I wish to thank you for the opportunity to follow up on your December 2016 Report *Hydro One – Management of Electricity Transmission and Distribution Assets.* As you may know, since becoming a private company in 2015, it has been a priority of Hydro One's executive leadership team to change the way Hydro One does business. We are transforming Hydro One into an industry leading customer-centric organization; advocating for our customers and communities; and have applied great rigor to ensure that at every level, we are driving productivity and operational efficiency throughout the Company.

While we are no longer bound by many of the rules governing a Crown Corporation, it is our pleasure to provide you with an update to our March 23rd, 2016 appearance before the Standing Committee on Public Accounts.

The *2015 Auditor General's Annual Report* highlighted 17 recommendation areas. Hydro One has committed to completing 71 remedial activities, of which:

- A total of 66 are now completed,
- Two (2) activities will be completed by May 2017, and
- The remaining 3 items will be completed by the end of 2017.

These recommendations have been grouped into 12 functional areas, with the appropriate recommendations noted in the subject headers along with a high-level brief on the activities completed and status below.

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1. Transmission & Distribution Systems Reliability Performance [Rec: 1, 9] (Complete ✓)

Recommendations included setting multi-year targets and timetables for reducing the frequency and duration of power outages and establishing cost-effective action plans and strategies to improve reliability performance. Also, to more thoroughly analyze outage data on both our transmission single and multi-circuit systems.

Activities Completed:

- To improve our ability to more accurately measure the effect of system investment on transmission reliability, Hydro One has supplemented its existing analysis with an additional model to quantify reliability risk which provides a directional indication of the effect of system investment on future transmission system reliability. This was introduced in the latest transmission rate filing application.

- Organizational changes were implemented in 2016 to establish a Planning Analytics team that works closely with the asset planners. This has enabled better performance analysis and integration into the Investment Planning process.

- Multi-year transmission and distribution reliability targets are in development and will be set by the end of April 2017.

- [redacted]

- [redacted]

- [redacted]

- [redacted]

- A comprehensive review of the outstanding deficiency reports (i.e. Defect Notifications, DRs) across all the asset hierarchies: T&D Stations & Lines (and Forestry program) has been completed, ensuring that no open DRs of a critical rating are unaddressed. This action ensures that no know deficiencies are overlooked and mitigates the impact equipment failures can have on planned outages.

- The Distribution System Plan (DSP) for the 2017-2022 timeframe has been developed and included in the recent rate filing submission. Strategic updates based on customer consultation feedback were incorporated in late 2016 along with adjusted investments in programs to improve reliability on specific under-performing assets.

- Distribution Strategies implemented include: Increasing Programs for line renewal and distribution station renewal; moving the location of rebuilt lines from off-road line sections to road allowances to improve access and facilitate fault-finding; enabling control room visibility and controllability of many devices, and prioritizing vegetation management programs to focus on reliability to large commercial/industrial customers.

- Distribution investment prioritization matrix has been updated to include greater weighting on reliability and more priority categories to give field crews more direction for work throughout and better visibility to important feeders. This includes off ramps in the program (forestry) to cut lower priority work if funding constraints are encountered.

- Monitoring of distribution work accomplishments on a more granular level (including project completions) are in place and reported monthly. Station refurbishments include monitoring and control in the scope of work and Line switch remote controllability is monitored annually to demonstrate number of controllable points.

2. Transmission and Distribution Systems Spend Related to Reliability [Rec 7, 13] (Complete ✓)

Recommendations included conducting an assessment of past maintenance expenditures and activities to determine what changes and improvements can be made to more effectively focus efforts on the critical factors that improve system reliability and to conduct benchmarking cost assessments related to reliability.

hydro one

Activities Completed:

- [redacted]
- [redacted]
- Distribution: An assessment of past maintenance expenditures and activities was completed, with a focus on critical factors and contributors to the distribution reliability measure. Strategic updates to distribution programs and projects, based on customer consultation feedback, were undertaken in Q3 2016, are supported by standardized Investment Summary Documents (ISDs) which are included in the Distribution System Plan.

- Distribution: Hydro One participated in benchmarking studies, to support its approaches to the investment, maintenance and sustainment activities included in the recently filed distribution rate application. Studies included vegetation management, pole replacement program, and station refurbishment program.

- Distribution: In 2016 Hydro One undertook an independent third-party review of the Distribution System Plan, providing unit cost validation for forestry, pole replacement and station refurbishment programs.

3. Transmission and Distribution Assets in Service Beyond Their Expected Life [Rec 3, 4, 12] (Complete ✓)

Recommendations included ensuring that its applications for rate increases to the Ontario Energy Board provide accurate information on its asset replacement activities, including whether it actually replaced assets in poor condition that were cited in previous applications and whether the same assets are being resubmitted. In addition, the findings have recommended targeting assets that have exceeded their planned useful service life and have the highest risk of failure and to re-assess its practice of replacing assets that are rated as being in good condition.

Activities Completed:

Context Clarification: As defined in our latest rate filing evidence, the expected service life is the average time in years that an asset can be expected to operate under normal system conditions. It does not imply the asset will need immediate replacement beyond this period of time. Hydro One operates a fleet of assets that are beyond expected service life. However, Hydro One's asset management objective is to maintain asset performance while minimizing full life cycle costs. This is accomplished through proper maintenance and timely replacement which are detailed in our application. This approach benefits ratepayers by minimizing rate increases.

- The Auditor General made a recommendation that Hydro One should be replacing assets based on their age rather than their condition. Hydro One employs investment planning processes, systems and trained planning Engineers to make prudent renewal plans based on multiple risk factors. The Company's experience is that our expected service life for various assets is appropriate given the operations, maintenance and conditions under which they are used. Hydro One does not replace assets that, while old, are in good working condition. The aim is to maximize the life expectancy of an asset and optimize work efficiency in order to derive the most value from our investments.

- The expected service life values for key asset classes was reviewed, found to be valid and in line with other utilities. Replacement rates and pacing of investments are reflected in both the transmission and distribution rate applications and aligned with the customer consultation needs and preferences.

- Transformers and breakers replacement strategies, selection process and execution methodology are clearly outlined in our rate filing evidence, providing the rationale behind each replacement.

- [redacted]

Context Clarification: The Auditor General made conclusions regarding the deferral or delay in replacing transmission transformers. This conclusion was solely based on asset condition information but without the benefit of the full information that Hydro One uses in determining asset replacement. Asset Condition is not the sole consideration in determining the need to replace an asset. These replacement decisions take into account many factors; conversely, assets in good condition may need replacement based on other factors such as environmental, health and safety, inadequate capacity and customer needs and preferences, while assets that are deteriorated may be deprioritized due to their having a less material impact on the system.

- [redacted]

4. Information Provided to OEB in Rate Applications [Rec 6] (Complete ✓)

Recommendations included ensuring that Hydro One's applications to the Ontario Energy Board for rate increases include accurate assessments of the condition of its assets.

Activities Completed:

Context Clarification: Hydro One endeavors to ensure all data submitted to the OEB for rate setting purposes accurately reflects its forward test year plans. In making this statement, the Auditor General appeared to have focused on investments that appeared in successive applications. In practice, investments are sometimes delayed due to work execution delays or other factors including changes in priority due to changing circumstances since the last rate application.

- To address this concern Hydro One has provided evidence supporting the 2017-2018 capital spending plans. These plans are based on the best information available at the time of filing the application. Hydro One is also prepared to explain variations from its previous plans and/or OEB approved spending amounts, compared to actual work completed. In addition, data quality improvement activities explained under item 5 below.

5. Asset Analytics System – Data Remediation [Rec 5, 11] (Mostly Complete ☑)

Recommendations included enhancing the Asset Analytics system to include information on all key factors that affect asset investment decisions; review and adjust current weighting assigned to risk factors to more accurately reflect their impact of asset condition and risk of failure; and make changes to procedures so that updates to Hydro One's data are complete, timely, reliable and accurate to ensure the information can support our asset replacement decision making process.

Activities Completed:

Context Clarification: The purpose of Asset Analytics is to provide asset planners with convenient access to asset data and assess emerging risk factors in an efficient manner. Decisions to replace assets are made by the asset planners in part based on Asset Analytics output and also based on many factors fully described in our rate filing evidence. Asset Analytics is one tool to aid in decision making, but it is not the only factor considered.

hydro one

A data remediation project was established in 2015 to address the data quality, population levels, processes and functionality issues related to the Asset Analytics tool. The focus was on data used in the AA algorithms.

Significant data and functionality improvements for Asset Analytics were completed over 2015-2016, with key activities as follows:

- Metrics: Dashboards for population levels, missing data reports and effectiveness of new assets completeness have been established for all of the Transmission and Distribution asset hierarchies.
- [redacted]
- Data: Distribution Stations data has been increased from 35% to 60%, Distribution Lines data is a current focus, starting at 69%, with a plan to get to 85% by year end. This work is in progress.
- GIS: A backlog of more than two years of TLGIS updates has been completed; and the distribution MADX translator has been fixed. With these fixes in place, transmission and distribution Planners can now see updates using the AA tool to view an accurate transmission and distribution network configuration in a GIS environment.
- Characteristics: ~30-40% of asset characteristics were discarded through workshops conducted to confirm "needs" tied to business needs. This eliminates many data fields that were being collected but not required. All characteristic data has been assigned a priority rating, high priority data population is showing great improvement.
- Data Templates: More than 250 data templates were revised, for the first time since "go-live" in 2008, enabling better data quality entry and providing clear direction to staff in LOB population roles.
- Legacy population strategies were employed; utilizing default values, data audits/comparisons to other systems, matching of records on key attributes, and some manual entry. All of these contributed to improving the quality and population level of the transmission hierarchies.
- In progress: Distribution data remediation continues, focusing on key activities such as asset counts across multiple systems (i.e. poles, pole-top transformers in GIS, SAP differ at present), development of Lines metrics dashboard and process fixes, targeted completion for main activities is by the end of 2017.

6. **Prioritization of the Distribution System Vegetation Management Program [Rec 10] (Complete ✓)**

   Recommendations included shortening the vegetation management cycle to be more cost-effective and in line with other similar local distribution companies and to change the way we prioritize lines that need clearing.

Activities Completed:

- A comprehensive review of the vegetation management program was undertaken and the prioritization model was improved to better support decision-making through the increase in reliability weighting on the risk matrix so that it becomes a major driver of prioritization. The program is reviewed annually.

- The vegetation management program has been adjusted to get feeders to an eight-year cycle over the longer term and in 2016, a new On-Cycle Maintenance Program was introduced. It is not economically feasible to get to a shorter (4-year) cycle as the Auditor General has recommended. Re-focusing work crew deployment and flexible locational work is also being implemented to enable improvement in unreliable areas.

7. **Preventive Maintenance Orders Backlog on Transmission Equipment [Rec 2] (Complete ✓)**

Recommendations included establishing a timetable that eliminates a growing preventive maintenance backlog and improved oversight of preventive maintenance programs to ensure it is completed as required and on time.

Activities Completed:

- Backlog: The identified backlog was partially due to a one-time generation of 2,440 PCB oil sampling orders (consisting of 12,500 equipment) to facilitate execution efficiency. These orders are not expected to be completed until 2021. These oil sample testing orders are to ascertain PCB level in oil filled equipment older than 1985. The result of these testing will determine if the PCB level is >50 ppm, which will help Hydro One determining whether a retro-filling or replacement is needed to comply with federal regulation to phase out PCB by 2025.

- Oversight: There are clearly outline accountabilities, authorities and processes around preventive maintenance orders generation, prioritization, redirection, scheduling, cancellation and deferral. This includes an over-release strategy (8% buffer above and beyond available resources) for maintenance orders to minimize outages. No critical preventive maintenance orders can be deferred without approval from Asset Management.

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8. Use of Smart Meters Capabilities to Improve Response to Power Outages [Rec 14] (Mostly Complete ☑)

Recommendations included improving customer service and lowering repair costs relating to power outages through more accurate and timely dispatches of its repair crews and to develop a plan and timetable for using our existing smart meter capability to pinpoint the location of customers with power outages.

Activities Completed:

- The Advanced Metering Infrastructure for Operations and the Advanced Metering Infrastructure for Analytics project charters have been reviewed and approved for implementation. This will allow for integration of the smart meter outage data to the outage management system, enable monitoring of asset loading information based on the network topology and proactively allow monitoring of our assets to avoid premature and possibly unplanned asset failures due to overloaded equipment.

- Our pilot technology has continued to deliver value. As a result, in addition to being able to ping meters to determine whether customers have power at their premises and avoid re-dispatching crews for further repair work, it will deliver further value by consolidating multiple meters without power and showing the scope of a power outage to the control room operators.

- *In progress*. Requirements and scope have been solidified and vendors chosen to do the work. Estimated completion and implementation is the end of 2017.

9. Electronic Devices Security Framework [Rec 8] (Complete ✓)

Recommendations included developing a comprehensive security framework to cover all electronic devices ensuring a robust and high level of security for the transmission system to mitigate the risk of service disruptions due to sabotage, vandalism, software viruses, or unauthorized changes to device software or controls.

Activities Completed:

- Hydro One has completed the development of a comprehensive security framework. This framework is called the Hydro One Security Code of Practice which includes the Security Policy and Security Operating Standards for the organization. The Code of Practice was completed and implemented as part of the NERC CIP v5 Standards.

10. **Transmission and Distribution Spare Transformers Fleet [Rec 15] (Complete ✓)**

Recommendations included improving the spares forecasting model; review and adjust spares inventory levels; develop plans to standardize in-service transformers and set targets and timelines for achieving savings.

Activities Completed:

Note: All activities are applicable to both the Transmission and Distribution power transformer spares.

- The Markov Model used to predict spare requirements have been updated; this model utilizes industry proven strategic spares risk analysis methodology to determine the appropriate quantity of operating spares.

- Spares Strategies. Transmission and Distribution Spares strategies have been approved. The strategies address key issues such as (i) reducing existing inventory, (ii) reinforcing first-in-first-out policy, and (iii) establish spare transformers shelf life to trigger mandatory deployment.

- Standardization. [redacted] Distribution power transformer fleet was reviewed and a refined set of procurement standards was established, reducing from 60 standards down to 45. Quantification of savings and timelines for achieving same has been established and documented.

- A comprehensive review and documentation of power transformer inventory at the Central Maintenance Shop (CMS) was completed and plans are in place to ensure required compliment totals are accurate and maintained. Asset data (including Level 1, 2, 3 spares information) has been updated in the system of record (i.e. SAP) to enable better tracking of available spares and their deployment status. Reviews will be completed annually.

11. Power Quality (PQ) Meters Data Use, Helping Customers Avoid Disruptions [Rec 16] (Complete ✓)

Recommendations included minimizing the number and impact of power quality events for its large customers through proactively using the data collected by its power meters to help assess the frequency and location of power quality events on its transmission and distribution systems, thereby improving the reliability.

Activities Completed:

- Hydro One has completed system studies to estimate the magnitude, frequency and duration of power quality voltage sag events. The results of these system studies provide an indication of the number, severity and duration of voltage sag events that a customer may experience and should be able to withstand. These studies are used by Hydro One to identify and undertake initiatives to minimize power quality impacts to customers and customers will be able to use these studies to inform their decisions regarding investments to improve their resilience.

- Hydro One is working with our customers to enable their revenue meters to also serve as PQ meters. This will allow for more effective assessment of PQ events and customer impact. We have also offered the services of 3rd party experts to assess customers' facilities and recommend measures to increase their resilience to minor to moderate PQ events.

12. Management Oversight Processes over Capital Project Costs [Rec 17] (Mostly Complete ☑)

Recommendations included conducting benchmarking to assess capital construction project costs; adherence to industry-normal contingency and escalation allowances; to improve management reporting and oversight of project costs showing actual project costs and completion dates compared to estimates.

Activities Completed:

- A Total Cost Benchmarking study (Navigant) was completed noting a number of benchmarks for project management performance. The internal work breakdown structure has been refined to enable a more efficient, consistent and accurate cost collection process for capturing project actual costs and comparisons.

- Contingency and escalation allowances have been reviewed and redefined. Escalation rates are now in line and consistent with our corporate business plan and we have implemented a quantitative project risk management methodology. In addition, a formalized project closure report process (including all project stakeholders) has been implemented to analyze the project plan and the effectiveness of its execution.

- >*__In progress__*. Hydro One is currently working to develop relationships with peer Canadian utilities to develop a consistent approach to benchmarking capital project work with an early focus on transmission lines projects and with a subsequent focus to be on substation projects.

I trust that you will find this information helpful. The response to your report is representative of a herculean effort within Hydro One as a part of our transformation from Crown Corporation to a world-class electricity services organization.

Thank you again for allowing us the opportunity to follow up on our 2015 appearance and for taking the time to review our progress in the intervening years.

Regards,

Daniel Levitan
Director, External Relations

OEB Staff Interrogatory # 10

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-02-01

At the above reference, Hydro One calculates the test period regulatory taxes sought for recovery in rates. On December 21, 2017, Hydro One filed Exhibit Q which provided updates to various areas of the previously filed evidence for this proceeding. As part of this update, Hydro One indicated a change to the regulatory tax balance being sought for recovery, however did not provide an updated detailed tax calculation in support of the revised amounts.

Interrogatory:

Please provide an updated regulatory tax calculation for the test period similar to the one provided in Exhibit C1/Tab7/Schedule 2, Attachment 1. Also please update other regulatory tax supporting documents as needed as a result of changes noted in Exhibit Q (i.e. CCA)

Response:

Please see below the updated Calculation of Utility Income Taxes and Calculation of Capital Cost Allowance (CCA).

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Test Years (2018 to 2022)
Year Ending December 31
($ Millions)

Line No.	Particulars		2018		2019		2020		2021		2022	
			(a)		(b)		(c)		(d)		(e)	
	Determination of Taxable Income											
1	Regulatory Net Income (before tax)	$	341.4	$	357.9	$	375.0	$	401.3	* $	415.1	*
2	Book to Tax Adjustments:											
3	Other Post Employment Benefits expense		22.2		22.0		21.6		20.3		21.3	
4	Other Post Employment Benefits payments		(25.8)		(27.2)		(27.9)		(27.7)		(29.9)	
5	Depreciation and amortization		397.1		418.2		433.1		452.1	*	465.9	*
7	Capital Cost Allowance and Cumulative Eligible Capital		(432.5)		(455.2)		(473.9)		(490.0)	*	(513.0)	*
8	Removal costs		(5.0)		(5.0)		(5.0)		(5.0)		(5.0)	
9	Environmental costs paid		(17.3)		(16.2)		(18.8)		(18.6)		(17.4)	
10	Hedge loss - amortization		0.1		0.1		0.1		0.1		0.1	
11	Non-deductible meals & entertainment		2.2		2.2		2.2		2.2		2.2	
12	Capital amounts expensed for accounting		6.2		6.2		6.2		6.2		6.2	
13	Research & Development ITC		1.0		1.0		1.0		1.0		1.0	
14	Federal Tax Credits		0.3		0.3		0.3		0.3		0.3	
15	Capitalized overhead costs deducted		(22.1)		(23.1)		(22.9)		(23.1)		(24.2)	
16	Capitalized pension costs deducted		(19.8)		(19.7)		(19.6)		(19.8)		(20.8)	
17	Debt Issuance costs - amortization		1.4		1.4		1.3		1.3		1.4	
18	Debt Issuance costs - 20(1)(e) deduction		(1.7)		(1.6)		(1.9)		(1.6)		(2.0)	
19	Premium/Discount - amortization		(0.4)		(0.4)		(0.5)		(0.5)		(0.3)	
20	Bond discount deduction		(0.0)		0.0		(0.1)		0.0		0.0	
21	Non-deductible LTIP		2.2		2.6		2.6		2.6		2.6	
22	Capitalized ESOP		(0.5)		(0.6)		(0.5)		(0.6)		(0.6)	
23	Non-deductible Share Grants		2.7		2.6		2.5		2.3		2.1	
		$	(89.9)	$	(92.6)	$	(100.1)	$	(98.7)	$	(110.1)	
24	Regulatory Taxable Income	$	251.4	$	265.3	$	274.9	$	302.6	$	304.9	
25	Corporate Income Tax Rate	%	26.50	%	26.50	%	26.50	%	26.50	%	26.50	%
26	Subtotal	$	66.6	$	70.3	$	72.8	$	80.2	$	80.8	
27	Less: R&D ITC / Ontario education credits		(1.2)		(1.3)		(1.3)		(1.3)		(1.3)	
28	Regulatory Income Tax	$	65.4	$	69.0	$	71.5	$	78.9	$	79.5	
	Tax Rates											
29	Federal Tax	%	15.00	%	15.00	%	15.00	%	15.00	%	15.00	%
30	Provincial Tax	%	11.50	%	11.50	%	11.50	%	11.50	%	11.50	%
31	Total Tax Rate	%	26.50	%	26.50	%	26.50	%	26.50	%	26.50	%

* Figures in 2021 and 2022 have been adjusted to incorporate the acquired LDCs.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost Allowance (CCA)
2017 to 2022 Networks Allocation to Dx
Year Ending December 31
($ Millions)

2017 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,438.1	29.5	1,467.6	14.75	1,452.8	4%	58.1	1,409.5
2	227.2	0.0	227.2	-	227.2	6%	13.6	213.5
3	10.5	0.0	10.5	-	10.5	5%	0.5	10.0
6	18.6	0.0	18.6	-	18.6	10%	1.9	16.7
8	92.9	29.5	122.5	14.76	107.7	20%	21.5	100.9
9	1.5	0.0	1.5	-	1.5	25%	0.4	1.1
10	119.0	33.3	152.3	16.64	135.6	30%	40.7	111.6
12	17.2	25.8	43.0	12.88	30.1	100%	30.1	12.9
13	12.6	6.0	18.7	3.02	15.6	0%	2.7	16.0
14.1	-	4.8	4.8	2.41	2.4	5%	0.1	4.7
17	16.5	0.0	16.5	-	16.5	8%	1.3	15.2
42	0.2	0.0	0.2	-	0.2	12%	0.0	0.2
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	3.6	0.0	3.6	-	3.6	30%	1.1	2.5
47	2,785.1	416.2	3,201.3	208.10	2,993.2	8%	239.5	2,961.8
50	18.4	22.3	40.7	11.13	29.5	55%	16.2	24.4
	4,761.5	567.4	5,328.9	283.68	5,045.2		427.8	4,901.1
CEC Continuity	22.0	0.0	22.0	283.7	22.0	7%	1.5	20.5

Less: Non regulatory items	(4.0)
Less: Tax Depreciation - Goodwill	
Total CCA for Revenue Requirement	422.7

2018 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,409.5	29.0	1,438.9	14.52	1,424.4	4%	57.0	1,381.9
2	213.5	0.0	213.5	-	213.5	6%	12.8	200.7
3	10.0	0.0	10.0	-	10.0	5%	0.5	9.5
6	16.7	0.0	16.7	-	16.7	10%	1.7	15.1
8	100.9	36.9	138.2	18.44	119.7	20%	23.9	114.2
9	1.1	0.0	1.1	-	1.1	25%	0.3	0.9
10	111.6	24.2	136.2	12.12	124.1	30%	37.2	99.0
12	12.9	24.0	37.0	11.98	25.0	100%	25.0	12.0
13	16.0	7.1	23.1	3.53	19.6	0%	3.0	20.1
14.1	4.7	5.1	9.9	2.57	7.3	5%	0.4	9.5
17	15.2	0.0	15.2	-	15.2	8%	1.2	14.0
42	0.2	0.0	0.2	-	0.2	12%	0.0	0.2
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	2.5	0.0	2.5	-	2.5	30%	0.8	1.8
47	2,961.8	437.5	3,404.7	218.76	3,185.9	8%	254.9	3,149.8
50	24.4	19.8	44.5	9.92	34.6	55%	19.0	25.5
	4,901.1	583.7	5,491.7	291.8	5,199.8		437.7	5,054.0
CEC Continuity	20.5	0.0	20.5	0.0	20.5	7%	1.4	19.0

Less: Non regulatory items	(4.2)
Less: Tax Depreciation - Goodwill	(2.4)
Total CCA for Revenue Requirement	432.5

2019 CCA Class	Opening UCC	Net Additions	UCC pre- 1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,381.9	32.3	1,414.2	16.17	1,398.1	4%	55.9	1,358.3
2	200.7	0.0	200.7	-	200.7	6%	12.0	188.7
3	9.5	0.0	9.5	-	9.5	5%	0.5	9.0
6	15.1	0.0	15.1	-	15.1	10%	1.5	13.6
8	114.2	22.6	136.8	11.29	125.5	20%	25.1	111.7
9	0.9	0.0	0.9	-	0.9	25%	0.2	0.6
10	99.0	27.2	126.2	13.61	112.6	30%	33.8	92.4
12	12.0	34.4	46.4	17.19	29.2	100%	29.2	17.2
13	20.1	8.9	28.9	4.43	24.5	0%	3.3	25.6
14.1	9.5	6.4	15.9	3.19	12.7	5%	0.6	15.3
17	14.0	0.0	14.0	-	14.0	8%	1.1	12.8
42	0.2	0.0	0.2	-	0.2	12%	0.0	0.2
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	1.8	0.0	1.8	-	1.8	30%	0.5	1.2
47	3,149.8	547.7	3,697.5	273.85	3,423.6	8%	273.9	3,423.6
50	25.5	31.3	56.8	15.67	41.1	55%	22.6	34.2
	5,054.0	710.8	5,764.8	355.4	5,409.4		460.4	5,304.4
CEC Continuity	19.0	0.0	19.0	0.0	19.0	7%	1.3	17.7

Less: Non regulatory items	(4.3)
Less: Tax Depreciation - Goodwill	(2.2)
Total CCA for Revenue Requirement	455.2

2020 CCA Class	Opening UCC	Net Additions	UCC pre- 1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,358.3	42.4	1,400.7	21.19	1,379.5	4%	55.2	1,345.5
2	188.7	0.0	188.7	-	188.7	6%	11.3	177.4
3	9.0	0.0	9.0	-	9.0	5%	0.5	8.6
6	13.6	0.0	13.6	-	13.6	10%	1.4	12.2
8	111.7	65.7	177.4	32.85	144.5	20%	28.9	148.5
9	0.6	0.0	0.6	-	0.6	25%	0.2	0.5
10	92.4	27.4	119.8	13.69	106.1	30%	31.8	88.0
12	17.2	18.2	35.4	9.11	26.3	100%	26.3	9.1
13	25.6	7.5	33.1	3.76	29.4	0%	3.6	29.5
14.1	15.3	6.0	21.3	3.00	18.3	5%	0.9	20.4
17	12.8	0.0	12.8	-	12.8	8%	1.0	11.8
42	0.2	0.0	0.2	-	0.2	12%	0.0	0.1
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	1.2	0.0	1.2	-	1.2	30%	0.4	0.9
47	3,423.6	522.8	3,946.4	261.41	3,685.0	8%	294.8	3,651.6
50	34.2	13.7	47.9	6.84	41.0	55%	22.6	25.3
	5,304.4	703.7	6,008.1	351.9	5,656.3		478.9	5,529.3
CEC Continuity	17.7	0.0	17.7	0.0	17.7	7%	1.2	16.5

Less: Non regulatory items	(4.2)
Less: Tax Depreciation - Goodwill	(2.0)
Total CCA for Revenue Requirement	473.9

2021 CCA Class	Opening UCC	Acquired LDCs	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,345.5	41.8	24.9	1412.2	12.4	1399.7	4%	56.0	1356.2
2	177.4	-	0.0	177.4	0.0	177.4	6%	10.6	166.7
3	8.6	1.6	0.0	10.2	0.0	10.2	5%	0.5	9.7
6	12.2	-	0.0	12.2	0.0	12.2	10%	1.2	11.0
8	148.5	1.1	18.9	168.5	9.5	159.0	20%	31.8	136.7
9	0.5	-	0.0	0.5	0.0	0.5	25%	0.1	0.4
10	88.0	0.1	27.3	115.3	13.6	101.7	30%	30.5	84.8
12	9.1	-	20.3	29.4	10.1	19.2	100%	19.2	10.1
13	29.5	-	7.0	36.4	3.5	32.9	0%	4.0	32.4
14	-	1.4	0.0	1.4	0.0	1.4	0%	0.1	1.3
14.1	20.4	-	5.8	26.2	2.9	23.3	5%	1.2	25.0
17	11.8	0.0	0.0	11.8	0.0	11.8	8%	0.9	10.9
42	0.1	-	0.0	0.1	0.0	0.1	12%	0.0	0.1
45	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0
46	0.9	0.0	0.0	0.9	0.0	0.9	30%	0.3	0.6
47	3,651.6	78.9	538.1	4268.6	269.0	3999.6	8%	320.0	3948.7
50	25.3	0.0	15.9	41.2	8.0	33.3	55%	18.3	22.9
	5,529.3	125.0	658.1	6,312.3	329.0	5,983.3		494.8	5,817.5
CEC Continuity	16.5	0.3	0.2	17.5	0.1	17.4	7%	1.2	16.3

Less: Non regulatory items	(4.1)
Less: Tax Depreciation - Goodwill	(1.9)
Total CCA for Revenue Requirement	490.0

2022 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,356.2	27.4	1,383.5	13.7	1,369.8	4%	54.8	1328.7
2	166.7	-	166.7	-	166.7	6%	10.0	156.7
3	9.7	-	9.7	-	9.7	5%	0.5	9.2
6	11.0	-	11.0	-	11.0	10%	1.1	9.9
8	136.7	46.4	183.1	23.2	159.9	20%	32.0	151.1
9	0.4	-	0.4	-	0.4	25%	0.1	0.3
10	84.8	27.6	112.4	13.8	98.6	30%	29.6	82.8
12	10.1	28.8	38.9	14.4	24.5	100%	24.5	14.4
13	32.4	6.4	38.8	3.2	35.6	0%	4.4	34.5
14	1.3	-	1.3	-	1.3	0%	0.1	1.1
14.1	25.0	5.7	30.7	2.8	27.9	5%	1.4	29.3
17	10.9	-	10.9	-	10.9	8%	0.9	10.0
42	0.1	-	0.1	-	0.1	12%	0.0	0.1
45	0.0	-	0.0	-	0.0	45%	0.0	0.0
46	0.6	-	0.6	-	0.6	30%	0.2	0.4
47	3,948.7	566.4	4,515.1	283.2	4,231.9	8%	338.5	4176.5
50	22.9	25.3	48.2	12.6	35.6	55%	19.6	28.6
	5,817.5	733.8	6,551.3	366.9	6,184.4		517.6	6,033.7
CEC Continuity	16.3	0.2	16.4	0.1	16.3	7%	1.1	15.3

Less: Non regulatory items	(4.1)
Less: Tax Depreciation - Goodwill	(1.7)
Total CCA for Revenue Requirement	513.0

OEB Staff Interrogatory # 11

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-03

At the above reference, Hydro One indicated that its 2016 Income Tax Return will be submitted as an update to the application once complete, however to date it has not been submitted.

Interrogatory:

Please provide the final (filed) Income Tax Return for 2016.

Response:

Please see attached the final Tax Return for 2016.

Canada Revenue Agency / Agence du revenu du Canada

Code 1501

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Use this form:
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: HYDRO ONE NETWORKS INC.	Enter one of the following:
Tax year From: 2016-01-01 (Year Month Day) To: 2016-12-31 (Year Month Day)	Business number (BN): 87086 5821 RC0001
050 Total number of projects you are claiming this tax year: 6	Social insurance number (SIN):

100 Contact person for the financial information	**105** Telephone number/extension	**110** Fax number
Glendy Cheung	(416) 345-6812	
115 Contact person for the technical information	**120** Telephone number/extension	**125** Fax number
Glendy Cheung	(416) 345-6812	(416) 345-6978

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 1 ☐ I elect to use the proxy method (Enter "0" on line 360 and complete Part 5.)

162 1 ☒ I choose to use the traditional method (Enter "0" on lines 355 and 502. Complete line 360.)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	1,595,483
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	1,595,483
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
Cost of materials consumed in performing SR&ED	320	+	
Cost of materials transformed in performing SR&ED	325	+	
Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts (see note 1)	340	+	4,275,930
b) Non-arm's length contracts (see note 1)	345	+	
Lease costs of equipment used **before 2014**:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	1,462,594
Third-party payments (see note 2) (complete Form T1263*)	370	+	1,089,769
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations may need to adjust line 118 of schedule T2SCH1)	380	=	8,423,776
Capital expenditures for depreciable property available for use **before 2014** (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	8,423,776

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		8,423,776
Deduct			
provincial government assistance for expenditures included on line 400	429	–	393,493
other government assistance for expenditures included on line 400	431	–	
non-government assistance for expenditures included on line 400	432	–	
SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	
sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	8,030,283
Add			
repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	1,491,890
SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	9,522,173
Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	9,522,173

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Note 1 – For contract expenditures made after 2013, no amounts for purchasing or leasing capital property can be included.

Note 2 – For third-party payments made after 2013, no amounts for purchasing or leasing capital property can be included.

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	492	8,423,776	496	
Add				
payment of prior years' unpaid amounts (other than salary or wages) (see note 5)	500 +			
prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +			
expenditures on shared-use equipment for property acquired **before 2014**			504 +	
qualified expenditures transferred to you (see note 3) (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	8,423,776	512 =	
Deduct (see note 4)				
provincial government assistance	513 –	393,493	514 –	
other government assistance	515 –		516 –	
non-government assistance and contract payments	517 –		518 –	
current expenditures (other than salary or wages) not paid within 180 days of the tax year end (see note 5)	520 –			
amounts paid in respect of an SR&ED contract to a person or partnership that is not a taxable supplier	528 –			
20% of expenditures included on lines 340 and 370	529 –	1,073,140		
prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
other deductions (see guide)	533 –		535 –	
non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	6,957,143	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	6,957,143
Add				
repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	6,957,143

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Note 3 – On line 510 (capital) – Only include expenditures made before 2014 by the transferor (performer). Complete the latest version of Form T1146.

Note 4 – On lines 514, 516, 518, 532, 535, 540, 543 and 546 – Only include amounts related to expenditures of a capital nature made before 2014.

Note 5 – For arm's length contracts, only include 80% of the contract amount.

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in Section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from lines 300 and 307) . . . . 810 +

Deduct

Bonuses, remuneration based on profits, and taxable benefits that were included on line 810 . . . . 812 –

Subtotal (line 810 minus 812) . . . . 814 =

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) 816 +

Salary base (total of lines 814 and 816) . . . . 818 =

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year, and less 10% of the salary base for number of days after 2013 in the tax year (use the formula in the guide-line 820) . . . . 820 =

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you. . . . .

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

	750	752	754	756
	Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1.	11-03 Extreme Space Weather Preparedness	40,311		
2.	15-03 Mission Critical Protection Scheme Upgrade Methods	553,077		
3.	16-01 Voltage Stabilization of Distributed Generation	239,513		
4.	16-02 Direct SCADA Architecture	14,027		
5.	16-03 Fibre-based Protection Control and Telecommunicatio	748,555		1,090,747
6.	16-04 Big Data Analytics for Advanced Distribution Solutions			3,185,183
	Total	1,595,483		4,275,930

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 3,058,077

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

For statistical purposes indicate whether the work you performed falls within the realm of Basic or Applied research (to advance scientific knowledge) or Experimental development (to achieve a technological advancement):

620 1 [X] Basic or Applied research **622** 1 [X] Experimental development

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	9
Technologists and technicians	634	5
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . [X]
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . [X]
3. completed Part 2 for each project . . . [X]
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . [X]
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . [X]

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* . . . [X]
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . [X]
3. retained documents to support the SR&ED work performed and SR&ED expenditures you claimed . . . [X]
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . [X]

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Claim preparer information

Information requested in this part must be provided for each claim preparer that has accepted consideration to prepare or assist in the preparation of this SR&ED claim. Certification is required on lines 935, 970, and 975.

A $1000 penalty may be assessed if the information requested below about the claim preparer(s) and billing arrangement(s), is missing, incomplete, or inaccurate. Where a claim preparer has prepared or assisted in the preparation of this SR&ED form, the claimant and the claim preparer will be jointly and severally, or solidarily, liable for the penalty.

935 Was a claim preparer engaged in any aspect of the preparation of this SR&ED claim?

1 [X] Yes (complete the claim preparer information table and lines 970 and 975 below)

2 [ ] No (complete lines 970 and 975)

Claim preparer information table

940	945	950	955	960	965
Name of claim preparer (company or individual)	Business number	Billing arrangement code (see codes*)	Billing rate (percentage, hourly/daily rate or flat fee)	Other billing arrangement(s) (Maximum 10 words)	Total fee paid, payable, or expected to pay
1. KPMG LLP	12236 3153 RT0001				
				Total	

*** Billing arrangement codes**

Code	Type of billing arrangement
1	Contingency fee arrangement – where the fee is based on a percentage of the investment tax credit earned
2	Hourly rate
3	Daily rate
4	Flat fee arrangement (lump sum)
5	Other arrangements – describe the arrangement in box 960 in 10 words or less

970 I, CHRIS LOPEZ, certify that the information provided in this part is complete
Name of authorized signing officer of the corporation, or individual (print)
and accurate.

Signature

975 2017-07-04
Year Month Day

Part 10 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 CHRIS LOPEZ
Name of authorized signing officer of the corporation, or individual

Signature

170 2017-07-04
Date

175 KPMG LLP
Name of person/firm who completed this form

Privacy Notice

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including assessment, audit, enforcement, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 “Scientific Research and Experimental Development” in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act*, and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our *Info Source* chapter can be found at www.cra.gc.ca/atip.

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

Complete this form for each third-party payment and attach it to Form T661.

For more information on third-party payments:

- See line 370 of Guide to Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party

[redacted]

702 Address (Street number and name)

[redacted]

City	Province / Territory	Postal Code
[redacted]	[redacted]	[redacted]

Total amount paid in the year

$ [redacted]

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)

1 [redacted]

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes [ ]	
712	Non-profit SR&ED corporation resident in Canada	1 Yes [ ]	
714	An approved university, college, research institute, or other similar institution	1 Yes [ ]	
716	Granting council	1 Yes [ ]	
718	Other corporation resident in Canada	1 Yes [X]	
721	Are you dealing at arm's length with the recipient?	1 Yes [X]	2 No [ ]

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes [ ]
732	Applied research	1 Yes [X]
734	Basic research	1 Yes [ ]

736 Briefly explain what the payment is for:

Research and Testing on the impact of humidity on protection
and control equipment

738 Briefly explain how the SR&ED is related to a business that you carry on:

Electricity distribution requires knowledge of the
impact of humidity on equipment logivity and functionality

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

Gain the knowledge and understanding to apply to existing
control and protection equipmment replacement timelines and
life-span assessment

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Required Information

1. Identification

701 Name of the third party
[redacted]

702 Address (Street number and name)
[redacted]

City	Province / Territory	Postal Code
[redacted]	[redacted]	[redacted]

Total amount paid in the year
$ [redacted]

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 [redacted]

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes	
712	Non-profit SR&ED corporation resident in Canada	1 Yes	
714	An approved university, college, research institute, or other similar institution	1 Yes	X
716	Granting council	1 Yes	
718	Other corporation resident in Canada	1 Yes	
721	Are you dealing at arm's length with the recipient?	1 Yes	X

2 No [ ]

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:

To fund applies research program to assess
opreation-time Distributed Generation Connection
Impact

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research results are directly related to the HONI
elctrical distribution business

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

The research project could yield significant benefits
to HONI and its customers

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Canada Revenue Agency / Agence du revenu du Canada

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- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
[redacted]

702 Address (Street number and name)
[redacted]

City	Province / Territory	Postal Code
[redacted]	[redacted]	[redacted]

Total amount paid in the year
$ [redacted]

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 [redacted]

Check the appropriate box to indicate the type of entity:

711 Approved association	1 Yes	
712 Non-profit SR&ED corporation resident in Canada	1 Yes	
714 An approved university, college, research institute, or other similar institution	1 Yes	X
716 Granting council	1 Yes	
718 Other corporation resident in Canada	1 Yes	
721 Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731 Experimental development	1 Yes	
732 Applied research	1 Yes	X
734 Basic research	1 Yes	

736 Briefly explain what the payment is for:
Compressed Air Energy Storage in Salt Caverns
R&D project

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research results are directly related to the HONI
elctrical distribution business

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

The research project could yield significant benefits
to HONI and its customers

Canada Revenue Agency / Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

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- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party

[redacted]

702 Address (Street number and name)

[redacted]

City	Province / Territory	Postal Code
[redacted]	[redacted]	[redacted]

Total amount paid in the year

$ [redacted]

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)

1 [redacted]

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes		
712	Non-profit SR&ED corporation resident in Canada	1 Yes		
714	An approved university, college, research institute, or other similar institution	1 Yes	X	
716	Granting council	1 Yes		
718	Other corporation resident in Canada	1 Yes		
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:

Progressive Failure Analyses Of Transmission Line
Structures Under The Action Of Downbursts And
Tornados

738 Briefly explain how the SR&ED is related to a business that you carry on:

The research results are directly related to the HONI
elctrical distribution business

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

The research project could yield significant benefits
to HONI and its customers

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

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T1263 E (15) Canada

Canada Revenue Agency | Agence du revenu du Canada

THIRD-PARTY PAYMENTS FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED)

Complete this form for each third-party payment and attach it to Form T661.

For more information on third-party payments:

- See line 370 of Guide to Form T661, S*cientific Research and Experimental Development (SR&ED) Expenditures Claim*;
- Third-Party Payments Policy;
- Consult our Web site: **www.cra.gc.ca/sred**.

Required Information

1. Identification

701 Name of the third party
[redacted]

702 Address (Street number and name)
[redacted]

City	Province / Territory	Postal Code
[redacted]	[redacted]	[redacted]

Total amount paid in the year
$ [redacted]

Identify the research project(s) performed by the third-party entity for the payment

706 Project title (and identification code if applicable)
1 [redacted]

Check the appropriate box to indicate the type of entity:

711	Approved association	1 Yes		
712	Non-profit SR&ED corporation resident in Canada	1 Yes		
714	An approved university, college, research institute, or other similar institution	1 Yes		
716	Granting council	1 Yes		
718	Other corporation resident in Canada	1 Yes	X	
721	Are you dealing at arm's length with the recipient?	1 Yes	X	2 No

2. Nature of payment

Check the appropriate box to indicate the type of entity:

The payment is for:

731	Experimental development	1 Yes	
732	Applied research	1 Yes	X
734	Basic research	1 Yes	

736 Briefly explain what the payment is for:

The payment is for the development of a cloud-based electricity distribution management system.

738 Briefly explain how the SR&ED is related to a business that you carry on:

A cloud-based electricity management system will allow Hydro
One to offer “Software-as-a-service” to the other power
utilities for managing their DMS in the cloud

740 Briefly explain how you are entitled to exploit the results of the SR&ED:

If the technological limitations were able to remove, Hydro One have the
contractual rights to leverage the results of the SR&ED to license the soluti
ons to other PUCs

Personal information is collected pursuant to subsections 37(1), 37(11), and 162(5.1) of the *Income Tax Act* (the Act) and is used for verification of compliance, administration and enforcement of the Scientific Research and Experimental Development (SR&ED) program requirements.

Information may also be used for the administration and enforcement of other provisions of the Act, including audit, enforcement action, collections, and appeals, and may be disclosed under information-sharing agreements in accordance with the Act. Incomplete or inaccurate information may result in assessment of monetary penalties and/or delays in processing SR&ED claims.

The social insurance number is collected pursuant to section 237 of the Act and is used for identification purposes.

Information is described in personal information bank CRA PPU 441 “Scientific Research and Experimental Development”, in the Canada Revenue Agency (CRA) chapter of *Info Source*. Personal information is protected under the *Privacy Act* and individuals have a right of access to, correction, and protection of their personal information. Further details regarding requests for personal information at the CRA and our Info Source chapter can be found at **http://www.cra.gc.ca/atip/**.

T1263 E (15)

Part 2 – Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

11-03 Extreme Space Weather Preparedness

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2011-04 (Year Month)	2016-06 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [ ] Employee directly involved in the project	**254** Name	
255 1 [ ] Other employee of the company	**256** Name	
257 1 [X] External consultant	**258** Name KPMG LLP	**259** Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No
266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No
267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1		Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1		Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1	X	Design, system architecture and source code	280	1	X	Contracts
275	1		Records of trial runs	281	1		Others, specify 282

Part 2 – Project information (continued)

Project number **2**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

15-03 Mission Critical Protection Scheme Upgrade Methods

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2014-11 (Year Month)	2018-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	**254** Name: Matt Efremov
255 1 [ ] Other employee of the company	**256** Name
257 1 [ ] External consultant	**258** Name / **259** Firm

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1		Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1	X	Design, system architecture and source code	280	1		Contracts
275	1		Records of trial runs	281	1		Others, specify 282

Part 2 – Project information (continued)

Project number **3**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

16-01 Voltage Stabilization of Distributed Generation

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2012-06 (Year Month)	2018-07 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project   **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [ ] Employee directly involved in the project	**254** Name
255 1 [ ] Other employee of the company	**256** Name
257 1 [X] External consultant	**258** Name: KPMG LLP — **259** Firm: KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3	

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1		Contracts
275	1		Records of trial runs	281	1		Others, specify 282

Part 2 – Project information (continued)

Project number **4**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

16-02 Direct SCADA Architecture

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2016-08 (Year Month)	2017-05 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 ☐ Continuation of a previously claimed project **210** 1 ☒ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 ☐ Yes 2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 ☐ Employee directly involved in the project	**254** Name	
255 1 ☐ Other employee of the company	**256** Name	
257 1 ☒ External consultant	**258** Name KPMG LLP	**259** Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3		

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 ☐ Yes 2 ☒ No
266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 ☐ Yes 2 ☒ No
267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 ☐ Yes 2 ☒ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1		Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1	X	Design of experiments	278	1		Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1	X	Design, system architecture and source code	280	1		Contracts
275	1		Records of trial runs	281	1		Others, specify 282

Part 2 – Project information (continued)

Project number **5**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

16-03 Fibre-based Protection Control and Telecommunication

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2015-05 (Year Month)	2016-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [ ] Employee directly involved in the project	**254** Name
255 1 [ ] Other employee of the company	**256** Name
257 1 [X] External consultant	**258** Name KPMG LLP — **259** Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	**261** Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 GE Multilin	86854 0907 RT0001
2 Tekstaff IT Solutions Inc.	83850 5923 RT0001
3 Procom Consultants Group Ltd.	87598 4874 RT0001
4	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1		Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1		Project records, laboratory notebooks	279	1	X	Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1	X	Contracts
275	1	X	Records of trial runs	281	1		Others, specify 282

Part 2 – Project information (continued)

Project number **6**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

16-04 Big Data Analytics for Advanced Distribution Solutions

202 Project start date: 2015-08 (Year Month)

204 Completion or expected completion date: 2017-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
1		
2		
3		

Section B – Project descriptions – You have chosen not to print the description of the project (lines 242, 244 and 246).

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [ ] Employee directly involved in the project **254** Name

255 1 [ ] Other employee of the company **256** Name

257 1 [X] External consultant **258** Name: KPMG LLP **259** Firm: KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3		

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	IBM	10244 4452 RC0001
2	Inergi LP	87155 5116 RC0001
3		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	X	Project planning documents	276	1	X	Progress reports, minutes of project meetings
271	1	X	Records of resources allocated to the project, time sheets	277	1	X	Test protocols, test data, analysis of test results, conclusions
272	1		Design of experiments	278	1		Photographs and videos
273	1	X	Project records, laboratory notebooks	279	1		Samples, prototypes, scrap or other artefacts
274	1		Design, system architecture and source code	280	1		Contracts
275	1		Records of trial runs	281	1		Others, specify 282

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2017-12-31

Business number 87086 5821 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2017-01-31	1,425,729	732,568			693,161
2017-02-28	1,425,729				1,425,729
2017-03-31	1,425,729				1,425,729
2017-04-30	1,425,729				1,425,729
2017-05-31	1,425,729				1,425,729
2017-06-30	1,425,729				1,425,729
2017-07-31	1,425,729				1,425,729
2017-08-31	1,425,729				1,425,729
2017-09-30	1,425,729				1,425,729
2017-10-31	1,425,729				1,425,729
2017-11-30	1,425,729				1,425,729
2017-12-31	1,425,721				1,425,721
Totals	17,108,740	732,568			16,376,172

Quarterly instalment workchart

Date	Quarterly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2017-03-31					
2017-06-30					
2017-09-30					
2017-12-31					
Totals					

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

		Yes	No
1 –	Is the corporation a Canadian-controlled private corporation (CCPC)?		X
2 –	Did the corporation claim any deduction under the section 125, during either the current or previous year?		X
3 –	Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?		
4 –	Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?		
5 –	Does the corporation have a perfect compliance history in the last 12 months?		

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	17,108,740	÷	12	=	1,425,729
	Monthly instalments required				1,425,729
Quarterly tax instalments required	17,108,740	÷	4	=	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account? ☐

2nd Monthly instalment base amount

Indicate: Part I tax							
Part VI, VI.1 and XIII.1 tax	+						
Federal adjustment for amalgamation, winding up or transfer	+						
Provincial tax, other than Alberta, Québec and Ontario	+						
Ontario tax	+	15,130,883					
Provincial adjustment for amalgamation, winding up or transfer	+						
Total	=	15,130,883	÷	12	=	1,260,907	**A**
1/12 of estimated current year credits (M below /12)					–	518,300	
Each of the first two instalment payments					=	742,607	**B**
Total tax from N below		17,108,740					
Amount B above x 2	–	1,485,214					
	=	15,623,526	÷	10	=	1,562,353	
Each of the remaining ten instalment payments					=	1,562,353	

2nd Quarterly instalment base amount

Indicate: Part I tax							
Part VI, VI.1 and XIII.1 tax	+						
Federal adjustment for amalgamation, winding up or transfer	+						
Provincial tax, other than Alberta, Québec and Ontario	+						
Ontario tax	+	15,130,883					
Provincial adjustment for amalgamation, winding up or transfer	+						
Total	=	15,130,883	÷	4	=	3,782,721	**A**
1/4 of estimated current year credits (M below /4)					–	1,554,900	
The first instalment payment					=		**B**
Total tax from N below		17,108,740					
Amount B above	–						
	=	17,108,740	÷	3	=	5,702,914	
Each of the remaining three instalment payments					=		

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷	12	=	
	Monthly instalments required				
Quarterly tax instalments required		÷	4	=	

Instalment base calculation

Federal tax

		1st instalment base method		Estimated tax method	
Taxable income					
Calculation of tax payable					
Federal part I tax					
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=		=		A
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+		+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+		+		
Logging tax credit	+		+		
Investment tax credit per Schedule 31	+		+		
Eligible Canadian bank deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=		=		B
Federal tax summary					
Total part I tax payable (A minus B)					C
Part VI tax	+		+		D
Part VI.1 tax	+		+		E1
Part XIII.1 tax	+		+		E2
Parts I, VI, VI.1 and XIII.1 **Total**	=		=		F
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=		=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=		=		G

Provincial tax

				1st instalment base method		Estimated tax method	
Provincial/territorial tax other than Alberta, Québec and Ontario before provincial refundable tax credits			+		+		H
Ontario tax							
Income tax							
Corporate minimum tax paid (credited)	+	23,328,339					
Special additional tax on life insurance corporations	+						
Total Ontario tax	=	23,328,339	+ ▶	23,328,339	+		I
Harmonized provincial tax (H + I)							
Provincial/territorial tax other than Alberta and Québec before provincial refundable tax credits			=	23,328,339	=		J
Provincial adjustments							
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365			x	365 / 365	x	365 / 365	
Subtotal			=	23,328,339	=		
Provincial adjustment for amalgamation, winding up or transfer			+		+	N/A	
Total provincial tax after adjustments			=	23,328,339	=		K
Total of tax before refundable credits**			=	23,328,339	=		L

Instalment base calculation (continued)

Estimated current year credits					
Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Provincial/territorial refundable tax credits other than Alberta, Québec and Ontario*	+		+		
Ontario refundable tax credits*	+	6,219,599	+		
Total estimated current year credits	=	6,219,599	=		**M**
Instalment base amount (L – M)		17,108,740			**N**

* For more details with regards to the impact of the refundable tax credits in the instalment base calculation, consult the Help.

** For instalments payable, the amount on line G will only be included in the amount of line L when it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

Identification

Business number (BN) 001 87086 5821 RC0001

Corporation's name
002 HYDRO ONE NETWORKS INC.

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes [ ] 2 No [X]
If **yes**, complete lines 011 to 018.
011 483 BAY STREET, 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO
Province, territory, or state: 016 ON
Country (other than Canada): 017 CA
Postal or ZIP code: 018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes [ ] 2 No [X]
If **yes**, complete lines 021 to 028.
021 c/o TAX DEPARTMENT
022 483 BAY STREET, 7TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 M5G 2P5

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? 030 1 Yes [ ] 2 No [X]
If **yes**, complete lines 031 to 038.
031 483 BAY STREET, 7TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2016-01-01
Tax year-end: 061 Year Month Day 2016-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [X] 2 No [ ]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	X	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?			T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170	X	29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	X	———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), or f) business limit assigned under subsection 125(3.2); or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? ..... 295 1 Yes [ ] 2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300 -549,209,136	A
Deduct:				
Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . 400 ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . 405 ______ B

Business limit (see notes 1 and 2 below) . . . . 410 ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x 415 *** ______ D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . 425 ______ F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . ______ G

Amount F **minus** amount G . . . . 427 ______ H

Small business deduction

Amount A, B, C, or H, whichever is the least ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 17 % = ______ 1

Amount A, B, C, or H, whichever is the least ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) 430 ______ I

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount 490	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] 500	L Business limit assigned to corporation identified in column J [4] 505
1.				
			Total 510 ______	Total 515 ______

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
(I) persons (other than the private corporation) with which the corporation deals at arm's length, or
(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B	
Amount K13 from Part 13 of Schedule 27			C	
Personal services business income	432		D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E	
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6*			G	
Subtotal (**add** amounts B to G)				H
Amount A **minus** amount H (if negative, enter "0")				I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %				J

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L	
Amount K13 from Part 13 of Schedule 27			M	
Personal services business income	434		N	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O	
Subtotal (**add** amounts L to O)				P
Amount K **minus** amount P (if negative, enter "0")				Q
General tax reduction – Amount Q **multiplied** by 13 %				R

Enter amount R on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** ______ A

Amount A ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 26 2 / 3 % = ______ 1

Amount A ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 30 2 / 3 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ ______ B

Foreign investment income from Schedule 7 . . . . . **445** ______ C

Amount C ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 9 1 / 3 % = ______ 3

Amount C ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 8 % = ______ 4

Subtotal (amount 3 **plus** amount 4) ______ D

Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0") . . . . . ______ E

Amount B **minus** amount E (if negative, enter "0") . . . . . ______ F

Foreign non-business income tax credit from line 632 on page 8 . . . . . ______ G

(Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 35 = ... ______ 5

(Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 38 2 / 3 = ... 38.66667 6

Subtotal (amount 5 **plus** amount 6) 38.6667 H

Amount G ______ x 100 / H = 100 / 38.6667 = ... ______ I

Taxable income from line 360 on page 3 . . . . . ______ J

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . ______ K

Amount I . . . . . ______ L

Foreign business income tax credit from line 636 on page 8 . . . . . ______ x 4 = ______ M

Subtotal (total of amounts K to M) ______ ▶ ______ N

Subtotal (amount J **minus** amount N) ______ O

Amount O ______ x (Number of days in the tax year before January 1, 2016 ______ / Number of days in the tax year 366) x 26 2 / 3 % = ______ 7

Amount O ______ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 30 2 / 3 % = ______ 8

Subtotal (amount 7 **plus** amount 8) ______ ______ P

Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . . ______ Q

Refundable portion of Part I tax – Amount F, P, or Q, whichever is the least . . . . . **450** ______ R

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct:				
Dividend refund for the previous tax year	465			
				A
Add:				
Refundable portion of Part I tax from line 450 on page 6			B	
Total Part IV tax payable from Schedule 3			C	
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
Subtotal (add amounts B, C, and line 480)				D
Refundable dividend tax on hand at the end of the tax year – Amount A **plus** amount D	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 .... 26,500,564 E

Amount E 26,500,564 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366) x 33 1/3 % = ________ 1

Amount E 26,500,564 x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 38 1/3 % = 10,158,550 2

Subtotal (amount 1 **plus** amount 2) 10,158,550 ▶ 10,158,550 F

Refundable dividend tax on hand at the end of the tax year from line 485 above .... G

Dividend refund – Amount F or G, whichever is less .... H

Enter amount H on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . . **550** ________ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business **555** ________ x (Number of days in the tax year after December 31, 2015: 366 / Number of days in the tax year: 366) x 5 % = **560** ________ B

Recapture of investment tax credit from Schedule 31 . . . **602** ________ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . ________ D

Taxable income from line 360 on page 3 . . . ________ E

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . ________ F

Net amount (amount E **minus** amount F) ________ ► ________ G

Amount D or G, whichever is less ________ x (Number of days in the tax year before January 1, 2016: ____ / Number of days in the tax year: 366) x 6 2 / 3 % = ________ 1

Amount D or G, whichever is less ________ x (Number of days in the tax year after December 31, 2015: 366 / Number of days in the tax year: 366) x 10 2 / 3 % = ________ 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2) . . . **604** ________ ________ H

Subtotal (**add** amounts A, B, C, and H) ________ I

Deduct:

Small business deduction from line 430 on page 4 . . . ________ J

Federal tax abatement . . . **608** ________

Manufacturing and processing profits deduction from Schedule 27 . . . **616** ________

Investment corporation deduction . . . **620** ________

Taxed capital gains **624** ________

Additional deduction – credit unions from Schedule 17 . . . **628** ________

Federal foreign non-business income tax credit from Schedule 21 . . . **632** ________

Federal foreign business income tax credit from Schedule 21 . . . **636** ________

General tax reduction for CCPCs from amount J on page 5 . . . **638** ________

General tax reduction from amount R on page 5 . . . **639** ________

Federal logging tax credit from Schedule 21 . . . **640** ________

Eligible Canadian bank deduction under section 125.21 . . . **641** ________

Federal qualifying environmental trust tax credit . . . **648** ________

Investment tax credit from Schedule 31 . . . **652** ________

Subtotal ________ ________ K

Part I tax payable – Amount I **minus** amount K . . . ________ L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	17,108,740
Total tax payable	770	17,108,740 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount H on page 7	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	17,841,308	
Total credits	890	17,841,308	17,841,308 B

Refund code 894 2 Overpayment 732,568

Balance (amount A **minus** amount B) -732,568

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to cra.gc.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 LOPEZ (Last name) 951 CHRIS (First name) 954 Senior Vice President, Finance (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2017-07-04 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-4575 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 Glendy Cheung (Name of other authorized person) 959 (416) 345-6812 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact: Glendy Cheung
Telephone number: (416) 345-6812

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Transfers from HOI	1,300,000
2016-01-28	Instalment	2,000,000
2016-03-01	Instalment	2,000,000
2016-03-31	Instalment	2,000,000
2016-04-29	Instalment	2,000,000
2016-05-31	Instalment	2,000,000
2016-06-28	2015 Overpayment ($2,741,865 - $200,557 tsf)	2,541,308
2016-07-29	Instalment	4,000,000

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 17,841,308 **A**

Total instalments credited to the taxation year per T9 17,841,308 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	1,074,000,000	1,007,000,000
	Total tangible capital assets	2008	+	28,073,000,000	26,495,000,000
	Total accumulated amortization of tangible capital assets	2009	–	9,789,000,000	9,283,000,000
	Total intangible capital assets	2178	+	846,000,000	756,000,000
	Total accumulated amortization of intangible capital assets	2179	–	330,000,000	279,000,000
	Total long-term assets	2589	+	3,327,000,000	3,436,000,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	23,201,000,000	22,132,000,000
Liabilities					
	Total current liabilities	3139	+	2,217,579,543	3,123,530,115
	Total long-term liabilities	3450	+	11,360,000,000	9,622,000,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	13,577,579,543	12,745,530,115
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	9,623,420,457	9,386,469,885
	Total liabilities and shareholder equity	3640	=	23,201,000,000	22,132,000,000
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	4,431,420,457	3,690,469,885

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	6,343,000,000	924,000,000
	Cost of sales	8518	–	3,365,000,000	490,000,000
	Gross profit/loss	8519	=	2,978,000,000	434,000,000
	Cost of sales	8518	+	3,365,000,000	490,000,000
	Total operating expenses	9367	+	2,114,297,188	346,485,015
	Total expenses (mandatory field)	9368	=	5,479,297,188	836,485,015
	Total revenue (mandatory field)	8299	+	6,343,000,000	924,000,000
	Total expenses (mandatory field)	9368	–	5,479,297,188	836,485,015
	Net non-farming income	9369	=	863,702,812	87,514,985
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	863,702,812	87,514,985
	Total other comprehensive income	9998	=	309,758	
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements		–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	22,472,359	-2,578,954,900
	Future (deferred) income tax provision	9995	–	114,779,881	
	Total – Other comprehensive income	9998	+	309,758	
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	726,760,330	2,666,469,885

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Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . **097** 1 Yes [X] 2 No [ ]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 [ ]
Completed a review engagement report . . . 2 [ ]
Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes [ ] 2 No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]
Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** 1 Yes [X] 2 No [ ]
Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes [X] 2 No [ ]
Is contingent liability information mentioned in the notes? . . . **106** 1 Yes [X] 2 No [ ]
Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [X] 2 No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	309,758
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [X] 2 No [ ]

If **yes**, you have to maintain a separate reconciliation.

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Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			726,760,330	A
Add:				
Provision for income taxes – current	101	22,472,359		
Provision for income taxes – deferred	102	114,779,881		
Interest and penalties on taxes	103	382,459		
Amortization of tangible assets	104	697,010,390		
Amortization of intangible assets	106	55,573,775		
Charitable donations and gifts from Schedule 2	112	233,603		
Scientific research expenditures deducted per financial statements	118	605,000		
Non-deductible meals and entertainment expenses	121	5,438,478		
Reserves from financial statements – balance at the end of the year	126	1,543,554,594		
Subtotal of additions		2,440,050,539 ▶	2,440,050,539	
Other additions:				
Capital items expensed	206	10,902,721		
Debt issue expense	208	211,970		
Financing fees deducted in books	216	3,807,750		

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Other additions - See attached schedule	10,263,159
2	Opening Regulatory Asset re OPEB & Env.	433,736,679
3	CCRA true up	20,406,462
4	Capital contributions received 12(1)(x)	122,143,117
	Total of column 2	586,549,417

Total of column 2	296	586,549,417		
Subtotal of other additions	199	601,471,858	601,471,858	
Total additions	500	3,041,522,397	3,041,522,397	B
Amount A **plus** amount B			3,768,282,727	C
Deduct:				
Capital cost allowance from Schedule 8	403	1,734,270,073		
Cumulative eligible capital deduction from Schedule 10	405	270,356,412		
Deferred and prepaid expenses	409	1,171,545		
Other reserves on line 280 from Schedule 13	413	46,625,639		
Reserves from financial statements – balance at the beginning of the year	414	1,860,864,654		
Contributions to deferred income plans from Schedule 15	417	59,367,455		
Subtotal of deductions		3,972,655,778 ▶	3,972,655,778	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	5,932,055

	1 Description 705	2 Amount 395
2	Capitalized interest expenses (a/c 761401/761402)	53,839,567
3	Capitalized operation, maintenance & admin.	62,017,452
4	Capitalized OPEB expenses	66,306,528
5	Capitalized removal costs	7,091,738
6	Other deductions - See attached schedule	4,373,524
7	Environmental payments	18,767,764
8	Tenant inducement - 13(7.4) election	4,364,340
9	Capital contributions - 13(7.4) election	122,143,117
	Total of column 2	344,836,085

Total of column 2	396	344,836,085		
Subtotal of other deductions	499	344,836,085	344,836,085	
Total deductions	510	4,317,491,863	4,317,491,863	D

Net income (loss) for income tax purposes (amount C **minus** amount D) . . . . -549,209,136 E

Enter amount E on line 300 of the T2 return.

T2 SCH 1 E (16) Canada

Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

Description	Operator (Note)	Amount	
Expensed legal fees related to debt issuance costs		211,970	00
	+		
	Total	211,970	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Operator (Note)	Amount	
Equipment under $2K (GL 620510)		708,113	00
Computer Application Software (GL 620046)	+	4,760,016	00
Computer System Software (GL 620040)	+	521	00
Project Cancellation Costs (GL 670000)	+	5,434,071	00
	Total	10,902,721	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 409 – Deferred and prepaid expenses

Title Line 409 – Deferred and prepaid expenses

Description	Operator (Note)	Amount	
Bond discount maturity (2006 - $450M / 10 YRS matured in 2016)		1,171,545	00
	+		
	Total	1,171,545	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Other Deductions

Description	Operator (Note)	Amount	
Bond premium/discount amortization (net P&L credit)		1,378,218	00
S.18(9.1) deduction	+	135,474	00
Unrealized mark-to-market gain on interest rate swap	+	49,619	00
2015 Prov to Return ITC CR's in OMA (re Co-op & Apprenticeship)	+	710,135	00
Landscaping adjustments	+	642,944	00
2011-2014 Fuel tax recovery taxed in 2015	+	346,469	00
2016 Ontario co-op overaccrual	+	556,205	00
2016 OBRI overaccrual	+	60,000	00
2016 Ontario apprenticeship overaccrual	+	494,460	00
	+		
	Total	4,373,524	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount	
Reverse insurance proceeds deduction reflected in S(13)		1,068,100	00
Remove PY Sch.13 - Regulatory Liability re DSC	+	6,490,085	00
Non-deductible fees	+	737,563	00
Non-deductible legal fees	+	728,563	00
Restricted Transmission asset write-off	+	12,014	00
LTIP expense	+	654,448	00
LTIP capitalized to OH	+	572,386	00
	Total	10,263,159	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

Explanatory note

Deferred Debt Issuance Costs (247900 & 247910)

Opening Balance	$32,973,789	
2016 Underwriting & Propectus Fees	9,316,355	deductible under s.20(1)(e)
Amortization of Underwriting Fees	(2,393,956)	
Amortization of Prospectus Fees	(224,221)	
Closing Balance	$39,671,967	

Description	Operator (Note)	Amount	
Amortization of Underwriting fee (GL #761780)		2,393,956	00
Amortization of Prospectus fee (GL #761790)	+	224,221	00
Amortization of Upfront Loan fee (included in GL #761730)	+	1,189,573	00
	+		
	Total	3,807,750	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

Description		Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1.	2012 Underwriting Fees	2012-01-01	4,645,000	3,716,000	929,000	
2.	2013 Underwriting Fees	2013-01-01	4,800,000	2,880,000	962,630	957,370
3.	2014 Underwriting Fees	2014-01-01	2,646,500	1,058,600	530,750	1,057,150
4.	2015 Underwriting Fees ($350M/5YRS 0.3%)	2015-04-30	105,000	21,000	21,058	62,942
5.	2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.	2016-02-24	5,460,000		1,094,992	4,365,008
6.	2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.	2016-11-18	3,500,000		701,918	2,798,082
7.	2012 Prospectus Fees	2012-01-01	125,593	100,475	25,118	
8.	2013 Prospectus Fees	2013-01-01	187,960	112,776	37,695	37,489
9.	2014 Prospectus Fees	2014-01-01	113,279	45,312	22,718	45,249
10.	2015 Prospectus Fees	2015-04-30	4,390	878	880	2,632
11.	2016 Prospectus Fees ($1,350M of new debt)	2016-02-24	207,156		41,545	165,611
12.	2016 Prospectus Fees ($950M of new debt)	2016-11-18	149,199		29,922	119,277
13.	2012 Upfront Fees	2012-05-10	1,591,600	1,272,800	318,800	
14.	2013 Upfront Fees	2013-05-31	1,072,000	643,200	214,987	213,813
15.	2014 Upfront Fees	2014-06-01	600,000	240,000	120,329	239,671
16.	2015 Upfront Fees	2015-06-01	1,560,000	312,000	312,855	935,145
17.	2016 Upfront Loan Fees ($2.3B of new debt)	2016-08-15	1,438,109		288,410	1,149,699
18.	2012 Legal Fees	2012-01-01	300,759	240,701	60,058	
19.	2013 Legal Fees	2013-01-01	701,225	420,954	140,629	139,642
20.	2014 Legal Fees	2014-01-01	45,898	18,361	9,205	18,332
21.	2015 Legal Fees	2015-01-01	66,396	13,300	13,316	39,780
22.	2015 Legal Fees	2015-11-05	63,475	2,141	12,730	48,604
23.	2016 Legal Fees	2016-01-01	211,970		42,510	169,460
		Totals	29,595,509	11,098,498	5,932,055	12,564,956

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: 2012 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2012-01-01	4,645,000	3,716,000	929,000	931,545	929,000	

2 Description: 2013 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2013-01-01	4,800,000	2,880,000	1,920,000	962,630	962,630	957,370

3 Description: 2014 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	2,646,500	1,058,600	1,587,900	530,750	530,750	1,057,150

4 Description: 2015 Underwriting Fees ($350M/5YRS 0.3%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-04-30	105,000	21,000	84,000	21,058	21,058	62,942

5 Description: 2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.392% + $350M/30YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-02-24	5,460,000		5,460,000	1,094,992	1,094,992	4,365,008

6 Description: 2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-11-18	3,500,000		3,500,000	701,918	701,918	2,798,082

7 Description: 2012 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2012-01-01	125,593	100,475	25,118	25,187	25,118	

8 Description: 2013 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2013-01-01	187,960	112,776	75,184	37,695	37,695	37,489

9 Description: 2014 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	113,279	45,312	67,967	22,718	22,718	45,249

10 Description: 2015 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-04-30	4,390	878	3,512	880	880	2,632

11 Description: 2016 Prospectus Fees ($1,350M of new debt)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-02-24	207,156		207,156	41,545	41,545	165,611

12 Description: 2016 Prospectus Fees ($950M of new debt)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-11-18	149,199		149,199	29,922	29,922	119,277

13 Description: 2012 Upfront Fees

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2012-05-10	1,591,600	1,272,800	318,800	319,192	318,800	

14 Description: 2013 Upfront Fees

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2013-05-31	1,072,000	643,200	428,800	214,987	214,987	213,813

15 Description: 2014 Upfront Fees

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2014-06-01	600,000	240,000	360,000	120,329	120,329	239,671

16 Description: 2015 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-06-01	1,560,000	312,000	1,248,000	312,855	312,855	935,145

17 Description: 2016 Upfront Loan Fees ($2.3B of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-08-15	1,438,109		1,438,109	288,410	288,410	1,149,699

18 Description: 2012 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2012-01-01	300,759	240,701	60,058	60,317	60,058	

19 Description: 2013 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2013-01-01	701,225	420,954	280,271	140,629	140,629	139,642

20 Description: 2014 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	45,898	18,361	27,537	9,205	9,205	18,332

21 Description: 2015 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-01-01	66,396	13,300	53,096	13,316	13,316	39,780

22 Description: 2015 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-11-05	63,475	2,141	61,334	12,730	12,730	48,604

23 Description: 2016 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 366 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-01-01	211,970		211,970	42,510	42,510	169,460

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward. Please note that the provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	500
[redacted]	100
[redacted]	750
[redacted]	325
[redacted]	250
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	300
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	200
[redacted]	100

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	600
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	200
[redacted]	100
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	400
[redacted]	800
[redacted]	100
[redacted]	500
[redacted]	1,136
[redacted]	51,079
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	300
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	300
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
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[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	400
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	1,000
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	400
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	500
[redacted]	500
[redacted]	1,000
[redacted]	2,363
[redacted]	1,000
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	100
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	200
[redacted]	50,000
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500
[redacted]	500

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	100
[redacted]	4,200
[redacted]	2,150
[redacted]	1,900
[redacted]	1,900
[redacted]	150
[redacted]	1,000
[redacted]	1,000
[redacted]	1,300
[redacted]	3,000
[redacted]	4,200
[redacted]	7,000
[redacted]	1,500
[redacted]	300
[redacted]	3,400
[redacted]	900
[redacted]	4,700
[redacted]	1,300
[redacted]	28,600
[redacted]	2,900
[redacted]	4,600
[redacted]	1,500
[redacted]	4,400
[redacted]	400
[redacted]	2,500
[redacted]	100
[redacted]	1,300
[redacted]	200
[redacted]	700
[redacted]	4,600
[redacted]	2,500
[redacted]	700
[redacted]	1,000
[redacted]	2,800
[redacted]	1,200
Subtotal	233,603
Add: Total donations of less than $100 each	
Total donations in current tax year	233,603

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		231,366	A	231,366	231,366
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240	231,366	B	231,366	231,366
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210	233,603		233,603	233,603
Subtotal (line 250 **plus** line 210)		233,603	C	233,603	233,603
Subtotal (amount B **plus** amount C)		464,969	D	464,969	464,969
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		464,969	E	464,969	464,969
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260				
Charitable donations closing balance (amount E **minus** amount on line 260)	280	464,969		464,969	464,969

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . **262** ______

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . ______ 1

Enter amount 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . **263** ______

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . ______ 2

Enter amount 2 on line 570 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia *Income Tax Act*.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016 and before January 1, 2019) . . . . **265** ______

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . ______ 3

Enter amount 3 on line 683 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia *Income Tax Act*.

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31	226,366	226,366	226,366
2nd prior year	2015-11-04	5,000	5,000	5,000
3rd prior year	2015-10-31			
4th prior year	2014-12-31			
5th prior year	2013-12-31			
6th prior year*	2012-12-31			
7th prior year	2011-12-31			
8th prior year	2010-12-31			
9th prior year	2009-12-31			
10th prior year	2008-12-31			
11th prior year	2007-12-31			
12th prior year	2006-12-31			
13th prior year	2005-12-31			
14th prior year	2004-12-31			
15th prior year	2003-12-31			
16th prior year	2002-12-31			
17th prior year	2001-12-31			
18th prior year	2000-12-31			
19th prior year	1999-12-31			
20th prior year				
21st prior year*				
Total (to line A)		231,366	231,366	231,366

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % .... F

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** .... **225** ________ G

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) .... **227** ________ H

The amount of the recapture of capital cost allowance in respect of charitable donations .... **230** ________

Proceeds of disposition, **less** outlays and expenses** .... ________ I

Capital cost** .... ________ J

Amount I or J, whichever is less .... **235** ________

Amount on line 230 or 235, whichever is less .... ________ K

Subtotal (**add** amounts G, H, and K) ________ L

Amount L **multiplied** by 25 % ________ M

Subtotal (amount F **plus** amount M) ________ N

Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less) .... ________ O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			A		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		B		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			C		
Subtotal (amount B **plus** amount C)			D		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			E		
Gifts of certified cultural property closing balance (amount D **minus** amount E)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2015-11-04			
3rd prior year	2015-10-31			
4th prior year	2014-12-31			
5th prior year	2013-12-31			
6th prior year*	2012-12-31			
7th prior year	2011-12-31			
8th prior year	2010-12-31			
9th prior year	2009-12-31			
10th prior year	2008-12-31			
11th prior year	2007-12-31			
12th prior year	2006-12-31			
13th prior year	2005-12-31			
14th prior year	2004-12-31			
15th prior year	2003-12-31			
16th prior year	2002-12-31			
17th prior year	2001-12-31			
18th prior year	2000-12-31			
19th prior year	1999-12-31			
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 4 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			F		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		G		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			J		
Gifts of certified ecologically sensitive land closing balance (amount I **minus** amount J)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2015-11-04			
3rd prior year	2015-10-31			
4th prior year	2014-12-31			
5th prior year	2013-12-31			
6th prior year*	2012-12-31			
7th prior year	2011-12-31			
8th prior year	2010-12-31			
9th prior year	2009-12-31			
10th prior year	2008-12-31			
11th prior year*	2007-12-31			
12th prior year	2006-12-31			
13th prior year	2005-12-31			
14th prior year	2004-12-31			
15th prior year	2003-12-31			
16th prior year	2002-12-31			
17th prior year	2001-12-31			
18th prior year	2000-12-31			
19th prior year	1999-12-31			
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 5 – Additional deduction for gifts of medicine

	Code	Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			K				
Deduct: Additional deduction for gifts of medicine expired after five tax years*	639						
Additional deduction for gifts of medicine at the beginning of the current tax year	640		L				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

	Code	Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			O		
Additional deduction for gifts of medicine closing balance (amount N **minus** amount O)	680				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2015-11-04			
3rd prior year	2015-10-31			
4th prior year	2014-12-31			
5th prior year	2013-12-31			
6th prior year*	2012-12-31			
7th prior year	2011-12-31			
8th prior year	2010-12-31			
9th prior year	2009-12-31			
10th prior year	2008-12-31			
11th prior year	2007-12-31			
12th prior year	2006-12-31			
13th prior year	2005-12-31			
14th prior year	2004-12-31			
15th prior year	2003-12-31			
16th prior year	2002-12-31			
17th prior year	2001-12-31			
18th prior year	2000-12-31			
19th prior year	1999-12-31			
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2015-12-31	
2nd prior year	2015-11-04	
3rd prior year	2015-10-31	
4th prior year	2014-12-31	
5th prior year	2013-12-31	
6th prior year*	2012-12-31	
7th prior year	2011-12-31	
8th prior year	2010-12-31	
9th prior year	2009-12-31	
10th prior year	2008-12-31	
11th prior year	2007-12-31	
12th prior year	2006-12-31	
13th prior year	2005-12-31	
14th prior year	2004-12-31	
15th prior year	2003-12-31	
16th prior year	2002-12-31	
17th prior year	2001-12-31	
18th prior year	2000-12-31	
19th prior year	1999-12-31	
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

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Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Schedule 3

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do **not** include dividends received from foreign non-affiliates.

Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.

When completing column J and K use the **special calculations provided in the notes**.

A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230

Total of column E (enter amount on line 402 of Schedule 1)

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received **before** 2016 241	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] 260	J Part IV tax before deductions. Dividends (from column G) received **before** 2016 **multiplied** by 33 1/3%[note 3] 270	K Part IV tax before deductions. Dividends received **after** 2015 (column F **minus** column G) **multiplied** by 38 1/3%[note 4] 275
Total of column F (include this amount on line 320 of the T2 Return)						**Total of column J** (enter amount on line a in Part 2)	**Total of column K** (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) . . . . . . ______ a

Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) . . . . ______ b

Part IV tax before deductions (amount a **plus** amount b) . . . . ______ ______ L

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) . . . . **320** ______

Subtotal (amount L **minus** line 320) ______ M

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . **330** ______ c

Non-capital losses from previous years claimed to reduce Part IV tax . . . . **335** ______ d

Current-year farm loss claimed to reduce Part IV tax . . . . **340** ______ e

Farm losses from previous years claimed to reduce Part IV tax . . . . **345** ______ f

Total losses applied against Part IV tax (total of amounts c to f) ______ g

If your tax year begins after December 31, 2015:

Amount g **multiplied** by 38 1 / 3 % . . . . ______ h

If your tax year begins before January 1, 2016:

Amount b or M whichever is less

______ ÷ 38 1 / 3 % . . . = ______ 1

Amount 1 or g, whichever is less . . . . ______ 2

Amount g **minus** amount 2 . . . . ______ 3

Amount 2 ______ x 38 1 / 3 % = ______ i

Amount 3 ______ x 33 1 / 3 % = ______ j

Subtotal (amount i **plus** amount j) ______ k

Amount h or amount k, whichever applies depending on your tax year start date . . . . ______ N

Part IV tax payable (amount M **minus** amount N, if negative enter "0") . . . . **360** ______
(enter amount on line 712 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	Hydro One Inc.	86999 4731 RC0001	2016-12-31	26,500,564	1,500,000
			Total of column R	26,500,564	

Total taxable dividends paid in the tax year to other than connected corporations . . . . 450 ______

Eligible dividends (included in line 450) . . . . 450a ______

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column R **plus** line 450) 460 26,500,564

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 26,500,564

Other dividends paid in the tax year (total of 510 to 540) . . . . ______

Total dividends paid in the tax year 500 26,500,564

Deduct:

Dividends paid out of capital dividend account . . . . 510 ______

Capital gains dividends . . . . 520 ______

Dividends paid on shares described in subsection 129(1.2) . . . . 530 ______

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . 540 ______

Subtotal (total of lines 510 to 540) ______ ______ S

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S) 26,500,564 T

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-549,209,136	A
Deduct: (increase a loss)				
Net capital losses deducted in the year (enter as a positive amount)		a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)		c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		d		
Subtotal (total of amounts a to d)		▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")			-549,209,136	C
Deduct: (increase a loss)				
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				D
Subtotal (amount C **minus** amount D)			-549,209,136	E
Add: (decrease a loss)				
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")			-549,209,136	G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		221,857,191	e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	221,857,191		221,857,191	H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110	549,209,136	h		
Subtotal (amount g **plus** amount h)		549,209,136		549,209,136	I
Subtotal (amount H **plus** amount I)				771,066,327	J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	**150**		i	
Section 80 – Adjustments for forgiven amounts	**140**		j	
Subsection 111(10) – Adjustments for fuel tax rebate			j.1	
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	**130**		k	
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	**135**		l	
Subtotal (total of amounts i to l)				K
Non-capital losses before any request for a carryback (amount J **minus** amount K)			771,066,327	L

Deduct – Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	**901**		m	
Second previous tax year to reduce taxable income	**902**		n	
Third previous tax year to reduce taxable income	**903**		o	
First previous tax year to reduce taxable dividends subject to Part IV tax	**911**		p	
Second previous tax year to reduce taxable dividends subject to Part IV tax	**912**		q	
Third previous tax year to reduce taxable dividends subject to Part IV tax	**913**		r	
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)				M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	**180**		771,066,327	N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	**200**		a	
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	**205**		b	
Subtotal (amount a **plus** amount b)				A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	**250**		c	
Section 80 – Adjustments for forgiven amounts	**240**		d	
Subtotal (amount c **plus** amount d)				B
Subtotal (amount A **minus** amount B)				C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	**210**			D
Unused non-capital losses that expired in the tax year (note 4)			e	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f	
Enter amount e or f, whichever is less	**215**		g	
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	**220**			E
Subtotal (total of amounts C to E)				F

Note

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)			**225**		G
Capital losses before any request for a carryback (amount F **minus** amount G)					H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		**951**		h		
Second previous tax year		**952**		i		
Third previous tax year		**953**		j		
Subtotal (total of amounts h to j)						I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)					**280**	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	**300**		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	**302**				A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	**305**		c		
Current-year farm loss (amount F in Part 1)	**310**		d		
Subtotal (amount c **plus** amount d)					B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	**350**		e		
Section 80 – Adjustments for forgiven amounts	**340**		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	**330**		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	**335**		h		
Subtotal (total of amounts e to h)					D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	**921**		i		
Second previous tax year to reduce taxable income	**922**		j		
Third previous tax year to reduce taxable income	**923**		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	**931**		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	**932**		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	**933**		n		
Subtotal (total of amounts i to n)					F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)				**380**	G

Note 8: A farm loss expires as follows:
after **10** tax years if it arose in a tax year ending before 2006; and
after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485		A
Minus the deductible farm loss:					
(amount A above ______ – $2,500) **divided** by 2 =		a			
Amount a or $ 15,000 (note 10), whichever is less				b	
	2,500	c			
Subtotal (amount b **plus** amount c)	2,500			2,500	B
Current-year restricted farm loss (amount A **minus** amount B)					C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired (note 11)	400		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402				D
Add:					
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405		f		
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	410		g		
Subtotal (amount f **plus** amount g)					E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	430		h		
Section 80 – Adjustments for forgiven amounts	440		i		
Other adjustments	450		j		
Subtotal (total of amounts h to j)					G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941		k		
Second previous tax year to reduce farming income	942		l		
Third previous tax year to reduce farming income	943		m		
Subtotal (total of amounts k to m)					I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480				J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:
after **10** tax years if it arose in a tax year ending before 2006; and
after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502				A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains	530		c		
Enter amount c on line 655 of Schedule 6.					
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)					D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back listed personal property loss to:					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)					F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** column 6)
	600	602	604	606	608		620
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
	630	632	634	636	638		650
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	Current-year limited partnership losses (from line 620)	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
	660	662	664	670	675	680
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A	549,209,136			N/A		549,209,136
1st preceding taxation year 2015-12-31	219,765,360	N/A		N/A			219,765,360
2nd preceding taxation year 2015-11-04	2,091,831	N/A		N/A			2,091,831
3rd preceding taxation year 2015-10-31		N/A		N/A			
4th preceding taxation year 2014-12-31		N/A		N/A			
5th preceding taxation year 2013-12-31		N/A		N/A			
6th preceding taxation year 2012-12-31		N/A		N/A			
7th preceding taxation year 2011-12-31		N/A		N/A			
8th preceding taxation year 2010-12-31		N/A		N/A			
9th preceding taxation year 2009-12-31		N/A		N/A			
10th preceding taxation year 2008-12-31		N/A		N/A			
11th preceding taxation year 2007-12-31		N/A		N/A			
12th preceding taxation year 2006-12-31		N/A		N/A			
13th preceding taxation year 2005-12-31		N/A		N/A			
14th preceding taxation year 2004-12-31		N/A		N/A			
15th preceding taxation year 2003-12-31		N/A		N/A			
16th preceding taxation year 2002-12-31		N/A		N/A			
17th preceding taxation year 2001-12-31		N/A		N/A			
18th preceding taxation year 2000-12-31		N/A		N/A			
19th preceding taxation year 1999-12-31		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total	221,857,191	549,209,136					771,066,327

* **This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ____________ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.*		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador Offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia Offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	1 Yes			167		
Total		129 G		H		

* "Permanent establishment" is defined in subsection 400(2).
** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line	Amount	Total	
Ontario basic income tax (from Schedule 500)	270			
Deduct: Ontario small business deduction (from Schedule 500)	402			
Subtotal				A6
Add:				
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)				C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")				F6
Deduct:				
Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario community food program donation tax credit for farmers (from Schedule 2)	420			
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")				G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278	23,328,339		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal		23,328,339	23,328,339	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			23,328,339	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	1,364,783		
Ontario apprenticeship training tax credit (from Schedule 552)	454	4,744,816		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470	110,000		
Subtotal		6,219,599	6,219,599	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		17,108,740	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	17,108,740

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . 050 1 Yes [ ] 2 No [X]

If **yes**, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

	1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	Foreign source
1	361	Woodstock Hydro Servic	Common	2016-08-31	32,055,289	32,055,289			
2	1,002	Haldimand County Hydro	Common	2016-08-31	72,265,957	72,265,957			
3	1,002	Haldimand County Energ	Common	2016-08-31	1,000,000	1,000,000			
				Totals	105,321,246	105,321,246			

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . 160 ______

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . ______ A

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	Foreign source
	Totals					B

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	Foreign source
Totals						D

Note
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	Foreign source
Totals						E

Note
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650	Foreign source
Totals						

Deduct: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . 655 ______

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . ______ F

Note
Net listed personal property losses can only be applied against listed personal property gains.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter 1; debt, enter 2 905	3 Date of Acquisition YYYY/MM/DD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	Foreign source
Totals							

Allowable business investment losses (ABILs) . . . . Total of Column 7 ______ x 50.0000 % = ______ G

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Note
Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss) . . . . H

Add: Foreign source

Capital gains dividend received in the year . . . . **875** I

Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves,* enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*) . . . . **880** J

Subtotal (total of amounts H to J) K

Deduct: Capital gains reserve closing balance (from Schedule 13) . . . . **885** L

Capital gains or losses, excluding ABILs (amount K **minus** amount L) . . . . **890** M

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note
When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act . . . . **895** a Foreign source

Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act* . . . . **896** b Foreign source

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . b-2 Foreign source

Subtotal (amount a **plus** amount b **plus** b-2) ▶ O

Subtotal (amount N **minus** amount O) P

Add:

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition . . . . **897** c

The total of all capital gains from the disposition of the actual property . . . . **898** d

Foreign source

Amount c or amount d, whichever is less Q

Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . x 2 = **899** R

Subtotal (total of amounts P to R) S

Deduct:

Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) . . . . x 2 = **901** T

Total capital gains or losses (amount S **minus** amount T) U

Taxable capital gains or total capital losses

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") V
Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U multiplied by 50.0000 %;
if amount U is negative, enter "0") . . . . W
Enter amount W on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Adjustments and transfers**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance***** (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ******	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1		5,269,956,351	42,159,798	31,689,460	0	21,079,899	5,322,725,710	4	0	0	212,909,028	5,130,896,581
2.	1b				43,965	0		43,965	6	0	0	2,638	41,327
3.	2		3,224,149,235			0		3,224,149,235	6	0	0	193,448,954	3,030,700,281
4.	3		312,733,292	10,307,573		0	5,153,787	317,887,078	5	0	0	15,894,354	307,146,511
5.	6		87,614,492	6,673,964		0	3,336,982	90,951,474	10	0	0	9,095,147	85,193,309
6.	8		192,705,356	98,948,920	1,863,526	182,315	49,383,303	243,952,184	20	0	0	48,790,437	244,545,050
7.	9		18,486,704			0		18,486,704	25	0	0	4,621,676	13,865,028
8.	10		362,213,402	56,288,186	886,264	1,842,626	27,222,780	390,322,446	30	0	0	117,096,734	300,448,492
9.	10	Class 10.1		1,806,950		0	903,475	903,475	30	0	0	271,043	1,535,907
10.	12		278,959,900	42,181,812	824,055	0	21,090,906	300,874,861	100	0	0	300,874,861	21,090,906
11.	13	255 Matheson Mississauga (WBS	716,457			0		716,457	NA	0	0	148,247	568,210
12.	13	483 Bay Street (WBS 300042991	21,933,445	925,937	-4,364,340	0	46,297	18,448,745	NA	0	0	1,738,326	16,756,716
13.	13	Arnprior Forestry Work Centre (V	195,195			0		195,195	NA	0	0	28,561	166,634
14.	13	Atrium on Bay (WBS 300040666)	43,472			0		43,472	NA	0	0	8,995	34,477
15.	13	Lionhead (WBS 700015140)	21,052			0		21,052	NA	0	0	4,356	16,696
16.	13	Newmarket Garage (WBS 30004(	72,372			0		72,372	NA	0	0	14,975	57,397
17.	13	Newmarket SC (WBS 700016578	6,442			0		6,442	NA	0	0	1,104	5,338
18.	13	Nipigon (WBS 700011829)	84,405			0		84,405	NA	0	0	17,465	66,940
19.	13	Orillia Forestry Work Centre (WB	208,944			0		208,944	NA	0	0	27,666	181,278
20.	13	Orleans OC (WBS 700010809)	1,416,830			0		1,416,830	NA	0	0	291,532	1,125,298
21.	13	Sudbury (WBS 700010356)	166,772			0		166,772	NA	0	0	16,961	149,811
22.	13	Sudbury 500 Barrydowne (WBS '	584,651	27,781		0	1,543	610,889	NA	0	0	67,073	545,359
23.	13	Thunder Bay Fleet Garage (WBS		98,778		0	9,878	88,900	NA	0	0	9,878	88,900
24.	14				2,240,626	0		2,240,626	NA	0	0	92,310	2,148,316

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
25.	17		106,432,629	28,908,293	38,004	0	14,454,147	120,924,779	8	0	0	9,673,982	125,704,944
26.	42		129,261,581	12,486,233		0	6,243,117	135,504,697	12	0	0	16,260,564	125,487,250
27.	43.2				31,707	0		31,707	50	0	0	15,854	15,853
28.	45		22,264,945		2,294	0		22,267,239	45	0	0	10,020,258	12,246,981
29.	46		10,529,948	2,577,449	2,144	0	1,288,725	11,820,816	30	0	0	3,546,245	9,563,296
30.	47		6,934,720,461	982,708,288	44,573,267	378,478	491,164,905	7,470,458,633	8	0	0	597,636,691	7,363,986,847
31.	50		276,752,082	94,758,389	187,737	0	47,379,195	324,319,013	55	0	0	178,375,457	193,322,751
32.	52		13,268,701			0		13,268,701	100	0	0	13,268,701	
33.	90	Land	1,377,671,749		-1,377,671,749	0			0	0	0		
34.	93	Future Use Inventory	86,315,777		-86,315,777	0			0	0	0		
35.	94	CIP	1,166,518,343		-1,166,518,343	0			0	0	0		
		Totals	19,896,004,985	1,380,858,351	-2,552,487,160	2,403,419	688,758,939	18,033,213,818				1,734,270,073	16,987,702,684

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	HYDRO ONE LIMITED	CA	80512 9962 RC0001	3					
2.	HYDRO ONE INC.	CA	86999 4731 RC0001	1					
3.	2486267 ONTARIO INC	CA	80232 6124 RC0001	3					
4.	2486268 ONTARIO INC	CA	80167 4078 RC0001	3					
5.	HYDRO ONE REMOTE COMMUNITIE	CA	87083 6269 RC0001	3					
6.	HYDRO ONE TELECOM INC.	CA	86800 1066 RC0001	3					
7.	HYDRO ONE TELECOM LINK LIMITE	CA	88786 7513 RC0001	3					
8.	MUNICIPAL BILLING SERVICES INC	CA	87560 6519 RC0001	3					
9.	HYDRO ONE LAKE ERIE LINK MANA	CA	87892 1519 RC0002	3					
10.	1938454 ONTARIO INC.	CA	86391 7795 RC0002	3					
11.	1943404 ONTARIO INC.	CA	86248 6123 RC0002	3					
12.	B2M GP INC.	CA	81838 1840 RC0001	3					
13.	HYDRO ONE B2M HOLDINGS INC	CA	82217 7531 RC0001	3					
14.	HYDRO ONE B2M LP INC.	CA	81838 2046 RC0001	3					
15.	NORFOLK ENERGY INC	CA	86289 0399 RC0001	3					
16.	NORFOLK POWER DISTRIBUTION II	CA	86289 2593 RC0001	2					
17.	HALDIMAND COUNTY ENERGY INC	CA	89076 2412 RC0001	2					
18.	HALDIMAND COUNTY HYDRO INC	CA	89075 9814 RC0001	2					
19.	WOODSTOCK HYDRO SERVICES IN	CA	89909 5012 RC0001	2					
20.	1937672 ONTARIO INC.	CA	81722 4561 RC0001	3					
21.	GREAT LAKES POWER TRANSMISSI	CA	83008 2335 RC0001	3					
22.	GREAT LAKES POWER TRANSMISSI	CA	84500 6386 RC0001	3					
23.	GREAT LAKES POWER TRANSMISSI	CA	82511 0216 RC0001	3					
24.	1228185 ONTARIO INC.	CA	88706 6090 RC0001	3					
25.	EAST WEST TIE INC.	CA	80044 2113 RC0001	3					
26.	HYDRO ONE EAST-WEST TIE INC.	CA	80105 5880 RC0001	3					
27.	1937680 ONTARIO INC.	CA	81930 4924 RC0001	3					
28.	1937681 ONTARIO INC.	CA	81722 4363 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")					200	3,832,387,613	A
Add: Cost of eligible capital property acquired during the taxation year	222	2,506,433					
Other adjustments	226						
Subtotal (line 222 plus line 226)		2,506,433	x 3 / 4 =	1,879,825			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =				C
amount B minus amount C (if negative, enter "0")				1,879,825		1,879,825	D
Amount transferred on amalgamation or wind-up of subsidiary					224	27,967,016	E
Subtotal (add amounts A, D, and E)					230	3,862,234,454	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G				
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H				
Other adjustments	246		I				
(add amounts G,H, and I)			x 3 / 4 =		248		J
Cumulative eligible capital balance (amount F minus amount J)						3,862,234,454	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)							
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249				
amount K		3,862,234,454					
less amount from line 249							
Current year deduction		3,862,234,454	x 7.00 % = 250	270,356,412 *			
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				270,356,412		270,356,412	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")					300	3,591,878,042	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)							N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1		
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2		
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3				
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4				
Line 3 minus line 4 (if negative, enter "0")					5		
Total of lines 1, 2 and 5					6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7				
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8				
Subtotal (line 7 plus line 8)	409				9		
Line 6 minus line 9 (if negative, enter "0")							O
Line N minus line O (if negative, enter "0")							P
Line 5				x 1 / 2 =			Q
Line P minus line Q (if negative, enter "0")							R
Amount R				x 2 / 3 =			S
Amount N or amount O, whichever is less							T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)						410	

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SCHEDULE 11

TRANSACTIONS WITH SHAREHOLDERS, OFFICERS, OR EMPLOYEES

Corporation's name	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

Provide the details of any transactions with shareholders, officers or employees that involve:

– payments the corporation made or amounts credited to the account of shareholders, officers, or employees, which were not part of their remuneration or reimbursement of expenses;

– assets the corporation sold to or purchased from shareholders, officers, or employees, including those for which an election was made under section 85; or

– loans or indebtedness to shareholders, officers, or employees, or persons connected with a shareholder, which were not repaid by the end of the taxation year.

	Relationship code (see note) 100	Payments $ 200	Reimbursement (Other than reimbursement of expenses) $ 300	Loans receivable from, or debts owing to $ 400	Assets sold or purchased $ 500	Does section 85 apply to assets sold or purchased? 550
1	1				105,321,246	Yes X No

Note: Enter the code number of the relationship that applies: (if more than one relationship exists, enter the lowest applicable number)
1 - Shareholder
2 - Officer
3 - Employee

T2 SCH 11 (00)

Canada

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130	135	46,625,639		140 46,625,639
Reserve for prepaid rent	☐	150	155			160
Reserve for refundable containers . .	☐	190	195			200
Reserve for unpaid amounts	☐	210	215			220
Other tax reserves	☐	230	235			240
Totals			275	46,625,639		280 46,625,639

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

T2 SCH 13 E (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Short Term	51,400,680		2,904,093		54,304,773
2	OPEB Liability Long Term	1,522,061,224		81,239,597		1,603,300,821
3	Environmental Short Term	20,251,013		5,528,831		25,779,844
4	Environmental Long Term	175,598,639			21,840,225	153,758,414
5	Regulatory Assets OPEB & Envi			-433,736,679	-13,359,726	-420,376,953
6	Net Regulatory Liabilities	57,557,752	5,619,854		27,632,985	35,544,621
7	Tenant Inducement	-2,348,770		8,962,417		6,613,647
8	Asset Retirement Obligations	8,831,270		270,646		9,101,916
9	General Bad Debt Reserve	3,908,361			3,908,361	
10	Insurance proceeds reserve	5,329,643			1,068,100	4,261,543
11	Donation Accrual	185,000			85,000	100,000
12	OPEB Liability - LDCs	1,167,902	1,163,519			2,331,421
13	Bonus payable			11,910,794		11,910,794
14	Contingent Liabilities	10,138,567		159,547		10,298,114
15						
	Reserves from Part 2 of Schedule 13			46,625,639		46,625,639
	Totals	1,854,081,281	6,783,373	-276,135,115	41,174,945	1,543,554,594

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc	483 Bay Street Toronto ON M5G 2P5			7,316,876		

T2 SCH 14 (99)

Canada

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	103,608,124	1059104			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	103,608,124	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	44,240,669	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")	59,367,455	C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

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SCHEDULE 24

FIRST-TIME FILER AFTER INCORPORATION, AMALGAMATION, OR WINDING-UP OF A SUBSIDIARY INTO A PARENT

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

This schedule must be filed by corporations for the first year of filing after incorporation, amalgamation, or by parent corporations filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act* during the current taxation year.

Part 1 – Type of operation

100 For those corporations filing for the first time after incorporation or amalgamation, please identify the type of operation that applies to your corporation:

Part 2 – First year of filing after amalgamation

For the first year of filing after an amalgamation, please provide the following information:

Name of predecessor corporation(s) 200	Business Number (If a corporation is not registered, enter "NR") 300

Part 3 – First year of filing after wind-up of subsidiary corporation(s)

For the parent corporation filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act*, please provide the following information:

	Name of subsidiary corporation(s) 400	Business Number (If a corporation is not registered, enter "NR") 500	Commencement date of wind-up (YYYY/MM/DD) 600	Date of wind-up (YYYY/MM/DD) 700
1	Woodstock Hydro Services Inc.	89909 5012 RC0001	2016-09-01	2016-09-01
2	Haldimand County Hydro Inc.	89075 9814 RC0001	2016-09-01	2016-09-01
3	Haldimand County Energy Inc.	89076 2412 RC0001	2016-09-01	2016-09-01

T2 SCH 24 (04) Canada

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SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $
1	[redacted]	[redacted]	09	678
2	[redacted]	[redacted]	09	223,917
3	[redacted]	[redacted]	09	3,451
4	[redacted]	[redacted]	09	98,724
5	[redacted]	[redacted]	09	5,041
6	[redacted]	[redacted]	09	16,440
7	[redacted]	[redacted]	09	10,137
8	[redacted]	[redacted]	09	8,753
9	[redacted]	[redacted]	09	13,576
10	[redacted]	[redacted]	09	35,916
11	[redacted]	[redacted]	09	326,474

	Name (list each payee separately) **100**	Address **200**	Payment code (see note 1) **300**	Amount $ **400**
12	[redacted]	[redacted]	09	217,965
13	[redacted]	[redacted]	09	160,322
14	[redacted]	[redacted]	09	13,273
15	[redacted]	[redacted]	02	10,245
16	[redacted]	[redacted]	02	10,207

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99) Canada

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the scientific research and experimental development (SR&ED) qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***:	
– after March 28, 2012, and before 2014	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . **103** ______
(Enter this amount on line 350 of Part 8)

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property ______ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B1
Deduct:				
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)				C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)				D1
Total credit available (line 220 **plus** amount D1)				E1
Deduct:				
Credit deducted from Part I tax (enter this amount at line D8 in Part 30)	260			
Credit carried back to the previous year(s) (from amount H1 in Part 6)		a		
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)				F1
Credit balance before refund (amount E1 **minus** amount F1)				G1
Deduct:				
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	

Total of lines 901 to 903 (enter amount H1 on line a in Part 5) ______ H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)		I1
Credit balance before refund (from amount G1 in Part 5)		J1
Refund (40 % of amount I1 or J1, whichever is less)		K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if you don't claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661)		6,957,143		
Contributions to agricultural organizations for SR&ED				
Deduct: Government assistance, non-government assistance, or contract payment				
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)*		6,957,143	350	6,957,143
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**			360	
Repayments made in the year (from line 560 on Form T661)			370	
Qualified SR&ED expenditures (total of lines 350 to 370)			380	6,957,143

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and

one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? .... **385** 1 Yes ☐ 2 No ☐

If you answered **no** to the question on line 385 above or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) .... **390** ____

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million .... **398** ____

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (from line 390 in Part 9) or $500,000, whichever is more	x 10 =		A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")			B2
$ 40,000,000 **minus** line 398 in Part 9	a		
Amount a **divided** by $ 40,000,000			C2
Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)*			D2

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* .... **400** ____ E2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D2 or E2 ____ x Number of days in the tax year 366 / 365 = ... ____ F2

Your SR&ED expenditure limit for the year (enter the amount from amount D2, E2, or F2, whichever applies) .... **410** ____

* Amount D2 or E2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=		G2
Line 350 **minus** line 410 (if negative, enter "0")	30	6,957,143					

Amount from line 430 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ b

Amount from line 430** 6,957,143 x (Number of days in the tax year after 2013 366 / Number of days in the tax year 366) x 15 % = 1,043,571 c

Subtotal (amount b **plus** amount c) . . . 1,043,571 — 1,043,571 H2

Line 410 **minus** line 350 (if negative, enter "0") . . . ______ d

Capital expenditures (from line 360 in Part 8) or amount d above, whichever is less* . . . **440** ______ x 35 % = ______ I2

Line 360 **minus** amount d above (if negative, enter "0") . . . **450** ______

Amount from line 450 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ e

Amount from line 450** ______ x (Number of days in the tax year after 2013 366 / Number of days in the tax year 366) x 15 % = ______ f

Subtotal (amount e **plus** amount f) . . . ______ — ______ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . ______

The ITC on the repayment (the credit) is calculated using the ITC rate that you used to determine your ITC when your qualified expenditures for ITC purposes were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate. ***

460		x	35 %	=	g
480		x	20 %	=	h
490		x	15 %	=	i

Subtotal (**add** amounts g to i) ______ — ______ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) . . . 1,043,571 L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013. For tax years that have a start date **after** 2013, multiply the amount by 15%.

*** If you are reporting a repayment for a tax year which included two calendar years with different rates (such as a 2014 tax year that started in 2013), the amount of repayment is allocated between the two ITC rates as follows:
- For the first part of the tax year, enter on the line next to the applicable ITC rate, the result of the following calculation: The full repayment amount **multiplied** by the number of days in the tax year which were in the first calendar year, **divided** by the total number of days in the tax year.
- For the last part of the tax year which is in the second calendar year, enter on the line next to the applicable ITC rate, the difference between the first part calculated above and the full repayment amount.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year			213,699	M2
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)				N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)	520		213,699	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540	1,043,571		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		1,043,571	1,043,571	O2
Total credit available (line 520 **plus** amount O2)			1,257,270	P2
Deduct:				
Credit deducted from Part I tax (enter this amount at line E8 in Part 30)	560			
Credit carried back to the previous year(s) (from amount S2 in Part 13)		j		
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount j, and line 580)				Q2
Credit balance before refund (amount P2 **minus** amount Q2)			1,257,270	R2
Deduct:				
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)	610			
ITC closing balance on SR&ED (amount R2 **minus** line 610)	620		1,257,270	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total of lines 911 to 913 (enter amount S2 at line j in Part 12)		S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11)		k
Refundable credits (amount k or amount R2 in Part 12, whichever is less)*		T2
Deduct:		
Amount T2 or amount G2 in Part 11, whichever is less		U2
Net amount (amount T2 **minus** amount U2; if negative, enter "0")		V2
Amount V2 **multiplied** by 40 %		W2
Add:		
Amount U2		X2
Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12)		Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (from amount R2 in Part 12)	1,257,270	Z2
Deduct:		
Amount Z2 or amount G2 in Part 11, whichever is less		AA2
Net amount (amount Z2 **minus** amount AA2; if negative, enter "0")	1,257,270	BB2
Amount BB2 or amount I2 in Part 11, whichever is less		CC2
Amount CC2 **multiplied** by 40 %		DD2
Add:		
Amount AA2		EE2
Refund of ITC (amount DD2 **plus** amount EE2)		FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal (enter amount A3 on line C3 in Part 17) A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) (enter amount B3 on line D3 in Part 17) B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line E3 in Part 17) **760** ______

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3)		F3

Enter amount F3 on line A8 in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826
Total of column 826	

			A4
Total pre-production mining expenditures (total of lines 810 to 821 and amount A4)	830		
Deduct:			
Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above	832		
Excess (line 830 **minus** line 832) (if negative, enter "0")			B4
Add:			
Repayments of government and non-government assistance	835		
Pre-production mining expenditures (amount B4 **plus** line 835)			C4

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year					D4
Deduct:					
Credit deemed as a remittance of co-op corporations	841				
Credit expired	845				
Subtotal (line 841 **plus** line 845)					E4
ITC at the beginning of the tax year (amount D4 **minus** amount E4)			850		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary			860		
Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18)	870	x 10 % =		a	
Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18)	872	x 5 % =		b	
Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18)	874	x 7 % =		c	
Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18)	876	x 4 % =		d	
Current year credit (total of amounts a to d)	880				F4
Total credit available (total of lines 850, 860, and amount F4)					G4
Deduct:					
Credit deducted from Part I tax (enter this amount at line F8 in Part 30)	885				
Credit carried back to the previous year(s) (from amount I4 in Part 20)				e	
Subtotal (line 885 **plus** amount e)					H4
ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4)			890		

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in subparagraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	
				Total of lines 921 to 923 (enter amount I4 on line e in Part 19)		I4

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	Apprentice 1	403A	67,787	6,779	2,000
2.	Apprentice 2	309A	43,419	4,342	2,000
3.	Apprentice 3	309A	45,121	4,512	2,000
4.	Apprentice 4	434A	16,145	1,615	1,615
5.	Apprentice 5	434A	65,928	6,593	2,000
6.	Apprentice 6	434A	46,542	4,654	2,000
7.	Apprentice 7	434A	75,332	7,533	2,000
8.	Apprentice 8	434A	74,027	7,403	2,000
9.	Apprentice 9	434A	42,687	4,269	2,000
10.	Apprentice 10	309A	4,570	457	457
11.	Apprentice 11	309A	27,183	2,718	2,000
12.	Apprentice 12	309A	15,850	1,585	1,585
13.	Apprentice 13	309A	14,720	1,472	1,472
14.	Apprentice 14	309A	15,900	1,590	1,590
15.	Apprentice 15	309A	14,870	1,487	1,487
16.	Apprentice 16	309A	14,870	1,487	1,487
17.	Apprentice 17	309A	15,510	1,551	1,551
18.	Apprentice 18	309A	15,020	1,502	1,502
19.	Apprentice 19	309A	15,830	1,583	1,583
20.	Apprentice 20	309A	58,585	5,859	2,000
21.	Apprentice 21	309A	42,916	4,292	2,000
22.	Apprentice 22	310T	27,823	2,782	2,000
23.	Apprentice 23	310T	75,725	7,573	2,000
24.	Apprentice 24	310T	51,170	5,117	2,000
25.	Apprentice 25	310T	49,242	4,924	2,000
26.	Apprentice 26	434A	48,167	4,817	2,000
27.	Apprentice 27	434A	58,904	5,890	2,000
28.	Apprentice 28	434A	64,440	6,444	2,000
29.	Apprentice 29	434A	57,577	5,758	2,000
30.	Apprentice 30	434A	79,538	7,954	2,000
31.	Apprentice 31	434A	68,392	6,839	2,000
32.	Apprentice 32	434A	61,637	6,164	2,000
33.	Apprentice 33	434A	55,754	5,575	2,000
34.	Apprentice 34	434A	57,180	5,718	2,000
35.	Apprentice 35	434A	69,653	6,965	2,000
36.	Apprentice 36	434A	67,063	6,706	2,000
37.	Apprentice 37	434A	58,113	5,811	2,000
38.	Apprentice 38	434A	60,521	6,052	2,000
39.	Apprentice 39	434A	55,807	5,581	2,000
40.	Apprentice 40	434A	76,505	7,651	2,000
41.	Apprentice 41	434A	63,352	6,335	2,000
42.	Apprentice 42	434A	63,511	6,351	2,000
43.	Apprentice 43	434A	57,962	5,796	2,000
44.	Apprentice 44	434A	72,067	7,207	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
45.	Apprentice 45	434A	45,418	4,542	2,000
46.	Apprentice 46	434A	62,754	6,275	2,000
47.	Apprentice 47	434A	77,387	7,739	2,000
48.	Apprentice 48	434A	63,550	6,355	2,000
49.	Apprentice 49	434A	68,005	6,801	2,000
50.	Apprentice 50	434A	56,913	5,691	2,000
51.	Apprentice 51	434A	58,708	5,871	2,000
52.	Apprentice 52	434A	71,937	7,194	2,000
53.	Apprentice 53	434A	60,155	6,016	2,000
54.	Apprentice 54	434A	58,547	5,855	2,000
55.	Apprentice 55	434A	59,076	5,908	2,000
56.	Apprentice 56	434A	65,281	6,528	2,000
57.	Apprentice 57	434A	55,324	5,532	2,000
58.	Apprentice 58	434A	66,140	6,614	2,000
59.	Apprentice 59	434A	54,078	5,408	2,000
60.	Apprentice 60	434A	73,168	7,317	2,000
61.	Apprentice 61	434A	71,342	7,134	2,000
62.	Apprentice 62	434A	72,545	7,255	2,000
63.	Apprentice 63	434A	67,282	6,728	2,000
64.	Apprentice 64	434A	63,533	6,353	2,000
65.	Apprentice 65	434A	65,896	6,590	2,000
66.	Apprentice 66	434A	62,932	6,293	2,000
67.	Apprentice 67	434A	59,458	5,946	2,000
68.	Apprentice 68	434A	2,091	209	209
69.	Apprentice 69	434A	65,767	6,577	2,000
70.	Apprentice 70	434A	46,124	4,612	2,000
71.	Apprentice 71	434A	79,727	7,973	2,000
72.	Apprentice 72	434A	45,559	4,556	2,000
73.	Apprentice 73	434A	63,663	6,366	2,000
74.	Apprentice 74	434A	61,178	6,118	2,000
75.	Apprentice 75	434A	69,465	6,947	2,000
76.	Apprentice 76	434A	66,630	6,663	2,000
77.	Apprentice 77	434A	65,594	6,559	2,000
78.	Apprentice 78	434A	62,535	6,254	2,000
79.	Apprentice 79	434A	67,570	6,757	2,000
80.	Apprentice 80	434A	67,288	6,729	2,000
81.	Apprentice 81	434A	63,940	6,394	2,000
82.	Apprentice 82	434A	61,486	6,149	2,000
83.	Apprentice 83	434A	66,957	6,696	2,000
84.	Apprentice 84	434A	57,809	5,781	2,000
85.	Apprentice 85	434A	36,618	3,662	2,000
86.	Apprentice 86	434A	64,208	6,421	2,000
87.	Apprentice 87	434A	59,925	5,993	2,000
88.	Apprentice 88	309A	42,928	4,293	2,000
89.	Apprentice 89	309A	42,202	4,220	2,000
90.	Apprentice 90	309A	49,131	4,913	2,000
91.	Apprentice 91	309A	49,171	4,917	2,000
92.	Apprentice 92	309A	74,879	7,488	2,000
93.	Apprentice 93	309A	38,147	3,815	2,000
94.	Apprentice 94	309A	57,885	5,789	2,000
95.	Apprentice 95	309A	43,593	4,359	2,000
96.	Apprentice 96	309A	59,792	5,979	2,000
97.	Apprentice 97	309A	56,531	5,653	2,000
98.	Apprentice 98	309A	49,780	4,978	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
99.	Apprentice 99	309A	55,511	5,551	2,000
100	Apprentice 100	433A	56,431	5,643	2,000
101	Apprentice 101	433A	65,484	6,548	2,000
102	Apprentice 102	434A	41,533	4,153	2,000
103	Apprentice 103	434A	69,360	6,936	2,000
104	Apprentice 104	434A	62,792	6,279	2,000
105	Apprentice 105	434A	62,965	6,297	2,000
106	Apprentice 106	434A	69,492	6,949	2,000
107	Apprentice 107	434A	60,865	6,087	2,000
108	Apprentice 108	434A	32,728	3,273	2,000
109	Apprentice 109	434A	62,339	6,234	2,000
110	Apprentice 110	434A	51,341	5,134	2,000
111	Apprentice 111	434A	53,727	5,373	2,000
112	Apprentice 112	434A	59,112	5,911	2,000
113	Apprentice 113	434A	60,413	6,041	2,000
114	Apprentice 114	434A	73,738	7,374	2,000
115	Apprentice 115	434A	66,459	6,646	2,000
116	Apprentice 116	434A	64,628	6,463	2,000
117	Apprentice 117	434A	61,036	6,104	2,000
118	Apprentice 118	434A	65,008	6,501	2,000
119	Apprentice 119	434A	73,915	7,392	2,000
120	Apprentice 120	434A	63,699	6,370	2,000
121	Apprentice 121	434A	62,590	6,259	2,000
122	Apprentice 122	434A	56,695	5,670	2,000
123	Apprentice 123	434A	57,214	5,721	2,000
124	Apprentice 124	434A	55,731	5,573	2,000
125	Apprentice 125	434A	66,356	6,636	2,000
126	Apprentice 126	434A	63,260	6,326	2,000
127	Apprentice 127	434A	55,677	5,568	2,000
128	Apprentice 128	434A	57,729	5,773	2,000
129	Apprentice 129	434A	59,681	5,968	2,000
130	Apprentice 130	434A	60,850	6,085	2,000
131	Apprentice 131	434A	74,614	7,461	2,000
132	Apprentice 132	434A	64,763	6,476	2,000
133	Apprentice 133	309A	38,460	3,846	2,000
134	Apprentice 134	309A	37,611	3,761	2,000
135	Apprentice 135	309A	53,463	5,346	2,000
136	Apprentice 136	434A	52,543	5,254	2,000
137	Apprentice 137	434A	51,352	5,135	2,000
138	Apprentice 138	434A	59,490	5,949	2,000
139	Apprentice 139	434A	44,177	4,418	2,000
140	Apprentice 140	434A	53,235	5,324	2,000
141	Apprentice 141	434A	49,873	4,987	2,000
142	Apprentice 142	434A	72,053	7,205	2,000
143	Apprentice 143	434A	54,821	5,482	2,000
144	Apprentice 144	434A	66,878	6,688	2,000
145	Apprentice 145	434A	50,928	5,093	2,000
146	Apprentice 146	434A	72,812	7,281	2,000
147	Apprentice 147	434A	51,119	5,112	2,000
148	Apprentice 148	434A	60,478	6,048	2,000
149	Apprentice 149	434A	61,622	6,162	2,000
150	Apprentice 150	434A	53,945	5,395	2,000
151	Apprentice 151	434A	2,776	278	278
152	Apprentice 152	309A	37,891	3,789	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
153	Apprentice 153	309A	30,733	3,073	2,000
154	Apprentice 154	310T	48,964	4,896	2,000
155	Apprentice 155	310T	40,474	4,047	2,000
156	Apprentice 156	310T	56,275	5,628	2,000
157	Apprentice 157	310T	39,035	3,904	2,000
158	Apprentice 158	309A	62,810	6,281	2,000
159	Apprentice 159	434A	52,049	5,205	2,000
160	Apprentice 160	434A	49,208	4,921	2,000
161	Apprentice 161	434A	47,900	4,790	2,000
162	Apprentice 162	434A	49,622	4,962	2,000
163	Apprentice 163	434A	57,138	5,714	2,000
164	Apprentice 164	434A	52,874	5,287	2,000
165	Apprentice 165	434A	47,934	4,793	2,000
166	Apprentice 166	434A	49,856	4,986	2,000
167	Apprentice 167	434A	44,821	4,482	2,000
168	Apprentice 168	434A	48,672	4,867	2,000
169	Apprentice 169	434A	47,400	4,740	2,000
170	Apprentice 170	434A	61,099	6,110	2,000
171	Apprentice 171	434A	47,738	4,774	2,000
172	Apprentice 172	434A	52,021	5,202	2,000
173	Apprentice 173	434A	48,307	4,831	2,000
174	Apprentice 174	434A	58,028	5,803	2,000
175	Apprentice 175	434A	58,254	5,825	2,000
176	Apprentice 176	309A	36,132	3,613	2,000
177	Apprentice 177	309A	38,595	3,860	2,000
178	Apprentice 178	309A	46,782	4,678	2,000
179	Apprentice 179	309A	36,702	3,670	2,000
180	Apprentice 180	309A	50,100	5,010	2,000
181	Apprentice 181	309A	41,242	4,124	2,000
182	Apprentice 182	309A	36,571	3,657	2,000
183	Apprentice 183	309A	33,098	3,310	2,000
184	Apprentice 184	434A	58,634	5,863	2,000
185	Apprentice 185	434A	52,208	5,221	2,000
186	Apprentice 186	434A	53,333	5,333	2,000
187	Apprentice 187	434A	50,158	5,016	2,000
188	Apprentice 188	434A	44,963	4,496	2,000
189	Apprentice 189	434A	66,828	6,683	2,000
190	Apprentice 190	434A	45,152	4,515	2,000
191	Apprentice 191	434A	56,442	5,644	2,000
192	Apprentice 192	434A	62,213	6,221	2,000
193	Apprentice 193	434A	55,852	5,585	2,000
194	Apprentice 194	434A	51,562	5,156	2,000
195	Apprentice 195	434A	52,544	5,254	2,000
196	Apprentice 196	434A	57,033	5,703	2,000
197	Apprentice 197	434A	64,496	6,450	2,000
198	Apprentice 198	434A	57,569	5,757	2,000
199	Apprentice 199	434A	53,386	5,339	2,000
200	Apprentice 200	434A	42,977	4,298	2,000
201	Apprentice 201	434A	40,893	4,089	2,000
202	Apprentice 202	434A	37,133	3,713	2,000
203	Apprentice 203	434A	43,813	4,381	2,000
204	Apprentice 204	434A	40,937	4,094	2,000
205	Apprentice 205	434A	42,735	4,274	2,000
206	Apprentice 206	434A	42,371	4,237	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
207	Apprentice 207	434A	48,567	4,857	2,000
208	Apprentice 208	434A	43,081	4,308	2,000
209	Apprentice 209	434A	43,348	4,335	2,000
210	Apprentice 210	434A	44,852	4,485	2,000
211	Apprentice 211	434A	39,683	3,968	2,000
212	Apprentice 212	434A	44,614	4,461	2,000
213	Apprentice 213	434A	40,732	4,073	2,000
214	Apprentice 214	434A	40,086	4,009	2,000
215	Apprentice 215	434A	51,089	5,109	2,000
216	Apprentice 216	434A	44,218	4,422	2,000
217	Apprentice 217	434A	51,114	5,111	2,000
218	Apprentice 218	434A	44,005	4,401	2,000
219	Apprentice 219	434A	44,072	4,407	2,000
220	Apprentice 220	434A	47,326	4,733	2,000
221	Apprentice 221	434A	45,825	4,583	2,000
222	Apprentice 222	434A	44,594	4,459	2,000
223	Apprentice 223	434A	45,270	4,527	2,000
224	Apprentice 224	434A	59,055	5,906	2,000
225	Apprentice 225	309A	52,916	5,292	2,000
226	Apprentice 226	309A	49,117	4,912	2,000
227	Apprentice 227	434A	34,568	3,457	2,000
228	Apprentice 228	434A	42,191	4,219	2,000
229	Apprentice 229	434A	57,331	5,733	2,000
230	Apprentice 230	434A	35,220	3,522	2,000
231	Apprentice 231	434A	34,357	3,436	2,000
232	Apprentice 232	434A	42,091	4,209	2,000
233	Apprentice 233	434A	39,922	3,992	2,000
234	Apprentice 234	434A	40,294	4,029	2,000
235	Apprentice 235	434A	37,159	3,716	2,000
236	Apprentice 236	434A	40,018	4,002	2,000
237	Apprentice 237	434A	31,100	3,110	2,000
238	Apprentice 238	434A	35,317	3,532	2,000
239	Apprentice 239	434A	38,307	3,831	2,000
240	Apprentice 240	434A	37,233	3,723	2,000
241	Apprentice 241	434A	49,234	4,923	2,000
242	Apprentice 242	434A	38,520	3,852	2,000
243	Apprentice 243	309A	32,804	3,280	2,000
244	Apprentice 244	434A	36,994	3,699	2,000
245	Apprentice 245	434A	41,301	4,130	2,000
246	Apprentice 246	309A	25,571	2,557	2,000
247	Apprentice 247	309A	25,179	2,518	2,000
248	Apprentice 248	309A	31,990	3,199	2,000
249	Apprentice 249	309A	30,204	3,020	2,000
250	Apprentice 250	309A	25,817	2,582	2,000
251	Apprentice 251	309A	26,719	2,672	2,000
252	Apprentice 252	309A	23,756	2,376	2,000
253	Apprentice 253	309A	39,807	3,981	2,000
254	Apprentice 254	309A	37,971	3,797	2,000
255	Apprentice 255	309A	19,608	1,961	1,961
256	Apprentice 256	309A	29,949	2,995	2,000
257	Apprentice 257	309A	24,796	2,480	2,000
258	Apprentice 258	309A	26,439	2,644	2,000
259	Apprentice 259	309A	26,767	2,677	2,000
260	Apprentice 260	309A	27,541	2,754	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
261	Apprentice 261	309A	17,788	1,779	1,779
262	Apprentice 262	309A	45,836	4,584	2,000
263	Apprentice 263	309A	30,144	3,014	2,000
264	Apprentice 264	434A	31,909	3,191	2,000
265	Apprentice 265	434A	31,896	3,190	2,000
266	Apprentice 266	434A	49,311	4,931	2,000
267	Apprentice 267	434A	39,010	3,901	2,000
268	Apprentice 268	434A	36,206	3,621	2,000
269	Apprentice 269	434A	31,814	3,181	2,000
270	Apprentice 270	434A	35,133	3,513	2,000
271	Apprentice 271	434A	37,082	3,708	2,000
272	Apprentice 272	434A	30,192	3,019	2,000
273	Apprentice 273	434A	31,156	3,116	2,000
274	Apprentice 274	434A	31,263	3,126	2,000
275	Apprentice 275	434A	33,287	3,329	2,000
276	Apprentice 276	434A	36,505	3,651	2,000
277	Apprentice 277	434A	37,657	3,766	2,000
278	Apprentice 278	434A	30,965	3,097	2,000
279	Apprentice 279	434A	34,011	3,401	2,000
280	Apprentice 280	434A	35,013	3,501	2,000
281	Apprentice 281	434A	32,704	3,270	2,000
282	Apprentice 282	434A	35,650	3,565	2,000
283	Apprentice 283	309A	7,300	730	730
284	Apprentice 284	309A	6,950	695	695
285	Apprentice 285	434A	35,428	3,543	2,000
286	Apprentice 286	434A	17,132	1,713	1,713
287	Apprentice 287	434A	4,889	489	489
288	Apprentice 288	434A	4,215	422	422
289	Apprentice 289	434A	4,554	455	455
290	Apprentice 290	434A	5,157	516	516
291	Apprentice 291	434A	4,980	498	498
292	Apprentice 292	434A	5,211	521	521
293	Apprentice 293	434A	34,609	3,461	2,000
294	Apprentice 294	434A	5,071	507	507
295	Apprentice 295	434A	4,421	442	442
296	Apprentice 296	434A	4,421	442	442
297	Apprentice 297	434A	5,250	525	525
298	Apprentice 298	434A	5,157	516	516
299	Apprentice 299	434A	4,571	457	457
300	Apprentice 300	434A	5,292	529	529
301	Apprentice 301	434A	56,054	5,605	2,000
302	Apprentice 302	434A	33,679	3,368	2,000
303	Apprentice 303	434A	60,352	6,035	2,000
304	Apprentice 304	434A	69,897	6,990	2,000
305	Apprentice 305	434A	80,595	8,060	2,000
306	Apprentice 306	434A	80,595	8,060	2,000
			Total current-year credit (total of column E) (enter amount A5 on line 640 in Part 22)		580,013 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

	Line			
ITC at the end of the previous tax year			1,890	B5
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)				C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)	625		1,890	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (from amount A5 in Part 21)	640	580,013		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		580,013	580,013	D5
Total credit available (line 625 **plus** amount D5)			581,903	E5
Deduct:				
Credit deducted from Part I tax (enter this amount at line G8 in Part 30)	660			
Credit carried back to the previous year(s) (from amount G5 in Part 23)			a	
Subtotal (line 660 **plus** amount a)				F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)	690		581,903	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day		Line		
1st previous tax year				Credit to be applied	931		
2nd previous tax year				Credit to be applied	932		
3rd previous tax year				Credit to be applied	933		
				Total of lines 931 to 933 (enter amount G5 on line a in Part 22)			G5

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** ______

Add:

Specified child care start-up expenditures from the current tax year . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . ______ A6

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . **725** ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . ______ B6

Add:

Repayments by the corporation of government and non-government assistance . . . . **735** ______

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . **745** ______

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . **755** ______ x $ 10,000 = ______ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . ______ E6

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year F6

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal (line 765 **plus** line 770) G6

ITC at the beginning of the tax year (amount F6 **minus** amount G6) 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (from amount E6 in Part 25) 780

Credit allocated from a partnership 782

Subtotal (total of lines 777 to 782) H6

Total credit available (line 775 **plus** amount H6) I6

Deduct:

Credit deducted from Part I tax (enter this amount at line H8 in Part 30) 785

Credit carried back to the previous year(s) (from amount K6 in Part 27) . . . . . . a

Subtotal (line 785 **plus** amount a) J6

ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6) 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2015-12-31	Credit to be applied	941	
2nd previous tax year	2015-11-04	Credit to be applied	942	
3rd previous tax year	2015-10-31	Credit to be applied	943	

Total of lines 941 to 943
(enter amount K6 on line a in Part 26) K6

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

the new child care space is no longer available; or

property that was an eligible expenditure for the child care space is:

- disposed of or leased to a lessee; or
- converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) **792**

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC **795**

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property **797**

Amount from line 795 or line 797, whichever is less A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799**

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) B7

Enter amount B7 on line B8 in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F3 in Part 17) A8

Recaptured child care spaces ITC (from amount B7 in Part 28) B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) C8

Enter amount C8 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) D8

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) E8

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) G8

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) I8

Enter amount I8 on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
580,013				580,013

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2015-12-31	1,890			1,890
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				*
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				
1999-12-31				
				*
Total	1,890			1,890

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	1,043,571				1,043,571

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2015-12-31	213,699			213,699
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				*
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				
1999-12-31				
				*
Total	213,699			213,699

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101	1,543,554,594		
Capital stock (or members' contributions if incorporated without share capital)	103	5,196,000,000		
Retained earnings	104	4,431,420,457		
Contributed surplus	105	5,000,000		
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	10,454,581,811		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		21,630,556,862	21,630,556,862	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			21,630,556,862	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	1,205,000,000		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		1,205,000,000	1,205,000,000	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		20,425,556,862	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	999
A loan or advance to another corporation (other than a financial institution)	402	3,083,701
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	3,084,700

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		20,425,556,862	C
Deduct: Investment allowance for the year (line 490)		3,084,700	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	20,422,472,162	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 20,422,472,162 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 20,422,472,162

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter “0“) . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ______ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ______ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Schedule 33 - Supplementary Schedule

Description	Operator (Note)	Amount	
LT Debt payable within a year (FS)		600,000,000	00
Primary Debt (FS)	+	9,340,000,000	00
Intercompany demand facility	+	462,000,000	00
Customer deposit (a/c 390000/391010/392000/392010)	+	46,625,639	00
Banked vacation (a/c 362100)	+	5,956,172	00
	Total	10454581811	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Schedule 33/CT23 - Supplementary Schedule

Description	Operator (Note)	Amount	
Prepaid insurance (a/c 277180)		2,125,605	00
Deposit -Bnft Provider (a/c 277290)	+	958,096	00
	+		
	+		
	Total	3,083,701	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Operator (Note)	Amount	
Schedule 13 Reserves		1,543,554,594	00
	+		
	+		
	+		
	Total	1,543,554,594	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	100			
Total eligible dividends paid in the tax year		150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")		160		B
Excessive eligible dividend designation (line 150 **minus** line 160)				C
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *		180		D
Subtotal (amount C **minus** amount D)				E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)		190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3	26,500,564			
Total taxable dividends paid in the tax year	26,500,564			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				G
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *		280		H
Subtotal (amount G **minus** amount H)				I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)		290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada

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Schedule 508

Ontario Research and Development Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016
  - 3.5% for tax years that start after May 31, 2016.
  - prorated for a tax year that ends on or after June 1, 2016 and include May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and non of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	7,350,636	A		
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	110,000	B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		7,240,636	C		
Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		7,240,636	▶	7,240,636	E
Eligible expenditures the corporation transferred to another corporation (cannot exceed amount E)				115	F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120: 7,240,636	G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 . . . . 210 ______ x 4.5 % = 215 ______ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

Number of days in the tax year before June 1, 2016 (152) / Number of days in the tax year 241 (366) x 4.5 % = 1.8689 % 1

Number of days in the tax year after May 31, 2016 242 (214) / Number of days in the tax year 243 (366) x 3.5 % = 2.0464 % 2

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 . . . . . . 211 ______ x percentage 3 3.9153 % = 216 ______ I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016	212				x	3.5 %	= 217		J
Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014	220		x	1 / 4 =		x 4.5 %	= 225		K
Eligible repayments (Total amount H to amount K)							229		L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)		x 4.5 %	= 200		M
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			205		N

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Eligible repayments (amount L in Part 2)			O
Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O)	230		P

For a tax year that ends on or after June 1, 2016 and includes May 31, 2016

Number of days in the tax year before June 1, 2016 / Number of days in the tax year	152 / 366	x	4.5 %	=	1.8689 %	4
Number of days in the tax year after May 31, 2016 / Number of days in the tax year	214 / 366	x	3.5 %	=	2.0464 %	5
Subtotal (percentage 4 **plus** percentage 5)					3.9153 %	6

Ontario SR&ED expenditure pool (amount G in Part 1)	7,240,636	x percentage 6	3.9153 %	= 201	283,493	Q
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *				206		R

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Eligible repayments (amount L in Part 2)			S
Current part of the ORDTC for tax years that end on or after June 1, 2016 and include May 31, 2016, (total of amounts Q to S)	231	283,493	T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1)		x 3.5 %	= 202		U
ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *			207		V

* If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Eligible repayments (amount L in Part 2)			W
Current part of the ORDTC for tax years that start after May 31, 2016 (total of amounts U to W)	232		X

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			67,131	Y
Deduct: ORDTC expired after 20 tax years	300			Z
ORDTC at the beginning of the tax year (amount Y **minus** amount Z)	305		67,131	AA
Add:				
ORDTC transferred to the corporation on amalgamation or windup	310			BB
Current part of ORDTC (amounts P, T or X in Part 3 whichever applies)		283,493 CC		

Are you waiving all or part of the current part of the ORDTC? . . . . . . **315** Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320	DD			
Subtotal (amount CC **minus** amount DD)		283,493	283,493	EE	
ORDTC available for deduction (total of amounts AA, BB and EE)			350,624		350,624 FF
Deduct:					
ORDTC claimed * (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)				GG	
ORDTC carried back to previous tax years (from Part 5)				HH	
Subtotal (amount GG **plus** amount HH)					II
ORDTC balance at the end of the tax year (amount FF **minus** amount II)	325				350,624 JJ

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2015-12-31	Credit to be applied	901	
2nd previous tax year	2015-11-04	Credit to be applied	902	
3rd previous tax year	2015-10-31	Credit to be applied	903	
		Total (enter amount on line HH in Part 4)		

Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year/Month/Day	Credit available
1999-12-31	
2000-12-31	
2001-12-31	
2002-12-31	
2003-12-31	
2004-12-31	
2005-12-31	
2006-12-31	
2007-12-31	

Tax year of origin (earliest tax year first) Year/Month/Day	Credit available
2008-12-31	
2009-12-31	
2010-12-31	
2011-12-31	
2012-12-31	
2013-12-31	
2014-12-31	
2015-10-31	
2015-11-04	
2015-12-31	67,131
Current tax year 2016-12-31	283,493
Total (equals line 325 in Part 4)	350,624

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – Complete this part If you meet all of the above conditions

	KK Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	LL Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	MM Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount NN, on line WW in Part 8 on page 5) ________ NN

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

	OO Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	PP Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	QQ Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) 740
1.			

	RR Amount determined by the formula (OO x PP) - QQ (using the columns above)	SS Federal ITC earned by the transferee for the qualified expenditure that was transferred 750	TT Amount from column RR or SS, whichever is less
1.			

Subtotal (enter amount UU on line XX below) UU

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter amount VV at line ZZ below) . . . . 760 VV

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line NN on page 4) . . . . . . WW

Recaptured federal ITC for Calculation 2 (amount from line UU above) XX

Amount WW **plus** amount XX . . . . x 23.56 % = YY

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line VV in Part 7) . . . . ZZ

Recapture of ORDTC (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

	Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED	8,423,776			
Add				
• payment of prior years' unpaid expenses (other than salary or wages)	+			
• prescribed proxy amount (Enter "0" if you use the traditional method)	+			
• expenditures on shared-use equipment			+	
• other additions	+		+	
Subtotal	= 8,423,776		=	
Less				
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–			
• 20% of contract expenditures for SR&ED performed on your behalf	– 1,073,140			
• prescribed expenditures not allowed by regulations	–		–	
• other deductions	–		–	
• non-arm's length transactions				
– expenditures for non-arm's length SR&ED contracts	–			
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–	
Subtotal	= 7,350,636	I	=	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			= 7,350,636	III

Enter amount III on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	23,201,000,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		23,201,000,000
Total revenue of the corporation for the tax year **	142	6,343,000,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		6,343,000,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	726,760,330
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	22,472,359		
Provision for deferred income taxes (debits)/cost of future income taxes	222	114,779,881		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		137,252,240		137,252,240 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	864,012,570

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	864,012,570	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available				C
Net income subject to CMT calculation (if negative, enter "0")		520	864,012,570	

Amount from line 520	864,012,570	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 366	x 4 % =		1
Amount from line 520	864,012,570	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	366 / 366	x 2.7 % =	23,328,339	2
			Subtotal (amount 1 **plus** amount 2)			23,328,339	3

Gross CMT: amount on line 3 above x OAF **	540	23,328,339	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		23,328,339	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		23,328,339	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		2,562,806	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		2,562,806	620	2,562,806	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				2,562,806	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)				2,562,806	J
Add:					
Net CMT payable (amount E from Part 3)		23,328,339			
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal		23,328,339		23,328,339	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	25,891,145	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					2,562,806	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	23,328,339	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			23,328,339	6		
Subtotal (if negative, enter "0")						N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)			6,219,599			
Subtotal (if negative, enter "0")						O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	
9th previous tax year	
8th previous tax year	
7th previous tax year	
6th previous tax year	
5th previous tax year	
4th previous tax year	
3rd previous tax year	
2nd previous tax year	
1st previous tax year	
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * .... _______ Q

Deduct:

CMT loss expired * .... 700 _______

CMT loss carryforward at the beginning of the tax year * (see note below) .... _______ 720 _______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) .... 750 _______

CMT loss available (line 720 **plus** line 750) .... _______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) .... _______

Subtotal (if negative, enter "0") _______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) .... _______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) .... 770 _______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	HYDRO ONE LIMITED	80512 9962 RC0001	0	0
2	HYDRO ONE INC.	86999 4731 RC0001	0	0
3	2486267 ONTARIO INC	80232 6124 RC0001	0	0
4	2486268 ONTARIO INC	80167 4078 RC0001	0	0
5	HYDRO ONE REMOTE COMMUNITIES INC.	87083 6269 RC0001	0	0
6	HYDRO ONE TELECOM INC.	86800 1066 RC0001	0	0
7	HYDRO ONE TELECOM LINK LIMITED	88786 7513 RC0001	0	0
8	MUNICIPAL BILLING SERVICES INC.	87560 6519 RC0001	0	0
9	HYDRO ONE LAKE ERIE LINK MANAGEMENT INC	87892 1519 RC0002	0	0
10	1938454 ONTARIO INC.	86391 7795 RC0002	0	0
11	1943404 ONTARIO INC.	86248 6123 RC0002	0	0
12	B2M GP INC.	81838 1840 RC0001	0	0
13	HYDRO ONE B2M HOLDINGS INC	82217 7531 RC0001	0	0
14	HYDRO ONE B2M LP INC.	81838 2046 RC0001	0	0
15	NORFOLK ENERGY INC	86289 0399 RC0001	0	0
16	NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	0	0
17	HALDIMAND COUNTY ENERGY INC	89076 2412 RC0001	0	0
18	HALDIMAND COUNTY HYDRO INC	89075 9814 RC0001	0	0
19	WOODSTOCK HYDRO SERVICES INC.	89909 5012 RC0001	0	0
20	1937672 ONTARIO INC.	81722 4561 RC0001	0	0
21	GREAT LAKES POWER TRANSMISSION HOLDINGS IN	83008 2335 RC0001	0	0
22	GREAT LAKES POWER TRANSMISSION INC.	84500 6386 RC0001	0	0
23	GREAT LAKES POWER TRANSMISSION HOLDING COI	82511 0216 RC0001	0	0
24	1228185 ONTARIO INC.	88706 6090 RC0001	0	0
25	EAST WEST TIE INC.	80044 2113 RC0001	0	0
26	HYDRO ONE EAST-WEST TIE INC.	80105 5880 RC0001	0	0
27	1937680 ONTARIO INC.	81930 4924 RC0001	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
28	1937681 ONTARIO INC.	81722 4363 RC0001	0	0
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Glendy Cheung	(416) 345-6812

Is the claim filed for a CETC earned through a partnership?* . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 843,179,826

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	[redacted]	Finance
2.	[redacted]	Finance
3.	[redacted]	Business Administration
4.	[redacted]	MBA
5.	[redacted]	MBA
6.	[redacted]	Business Administration
7.	[redacted]	Business Economics
8.	[redacted]	Business Economics
9.	[redacted]	Computer Science
10.	[redacted]	Computer Science
11.	[redacted]	Computer Science
12.	[redacted]	Business Administration
13.	[redacted]	Business Administration
14.	[redacted]	Business Administration
15.	[redacted]	Business Administration
16.	[redacted]	Business Administration
17.	[redacted]	Business Administration
18.	[redacted]	Business Administration
19.	[redacted]	Accounting
20.	[redacted]	Accounting
21.	[redacted]	MBA
22.	[redacted]	MBA
23.	[redacted]	Business Administration

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	[redacted]	Business Administration
25.	[redacted]	Business Administration
26.	[redacted]	Business Administration
27.	[redacted]	Business Administration
28.	[redacted]	Business Administration
29.	[redacted]	Accounting (Masters)
30.	[redacted]	Computer Science
31.	[redacted]	Business Economics (Masters)
32.	[redacted]	Business Economics (Masters)
33.	[redacted]	Accounting (Masters)
34.	[redacted]	Accounting (Masters)
35.	[redacted]	Electrical Engineering
36.	[redacted]	Electrical Engineering Technology
37.	[redacted]	Powerline Technician
38.	[redacted]	Powerline Technician
39.	[redacted]	Powerline Technician
40.	[redacted]	Powerline Technician
41.	[redacted]	Civil Engineering Technology
42.	[redacted]	Civil Engineering Technology
43.	[redacted]	Electrical Engineering Technology
44.	[redacted]	Electrical Engineering Technology
45.	[redacted]	Electrical Engineering Technology
46.	[redacted]	Business Human Resources
47.	[redacted]	Electrical Engineering Technology
48.	[redacted]	Electrical Engineering Technology
49.	[redacted]	Electrical Engineering Technology
50.	[redacted]	Electrical Engineering Technology
51.	[redacted]	Electrical Engineering Technology
52.	[redacted]	Electrical Engineering Technology
53.	[redacted]	Electrical Engineering Technology
54.	[redacted]	Computer Systems Technician
55.	[redacted]	Business Administration
56.	[redacted]	Electrical Engineering Technician
57.	[redacted]	Electrical Engineering Technician
58.	[redacted]	Electrical Engineering Technology
59.	[redacted]	Civil Engineering Technology
60.	[redacted]	Electrical Engineering Technology
61.	[redacted]	Electrical Engineering Technology
62.	[redacted]	Electrical Engineering Technology
63.	[redacted]	Electrical Engineering Technology
64.	[redacted]	Electrical Engineering Technology
65.	[redacted]	Electrical Engineering Technician
66.	[redacted]	Electrical Engineering Technology
67.	[redacted]	Civil Engineering Technology
68.	[redacted]	Civil Engineering Technology
69.	[redacted]	Business Administration
70.	[redacted]	Business Administration
71.	[redacted]	Electrical Engineering Technology
72.	[redacted]	Electrical Engineering Technology
73.	[redacted]	Electrical Engineering Technician
74.	[redacted]	Electrical Engineering Technician
75.	[redacted]	Business
76.	[redacted]	Electrical Engineering Technology
77.	[redacted]	Electrical Engineering Technology
78.	[redacted]	Computer Programmer Analyst

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	[redacted]	Electrical Engineering Technology
80.	[redacted]	Business
81.	[redacted]	Electrical Engineering Technician
82.	[redacted]	Electrical Engineering Technology
83.	[redacted]	Electrical Engineering Technology
84.	[redacted]	Electrical Engineering Technician
85.	[redacted]	Electrical Engineering Technology
86.	[redacted]	Electrical Engineering Technology
87.	[redacted]	Human Resources
88.	[redacted]	Human Resources
89.	[redacted]	Electrical Engineering Technology
90.	[redacted]	Electrical Engineering Technology
91.	[redacted]	Electrical Engineering Technology
92.	[redacted]	Electrical Engineering Technology
93.	[redacted]	Electrical Engineering Technology
94.	[redacted]	Electrical Engineering Technology
95.	[redacted]	Electrical Engineering Technician
96.	[redacted]	Electrical Engineering Technician
97.	[redacted]	Electrical Engineering Technology
98.	[redacted]	Electrical Engineering Technology
99.	[redacted]	Business Administration
100.	[redacted]	Business Administration
101.	[redacted]	Electrical Engineering Technology
102.	[redacted]	Electrical Engineering Technology
103.	[redacted]	Electrical Engineering Technology
104.	[redacted]	Electrical Engineering Technology
105.	[redacted]	Human Resources Management
106.	[redacted]	Electrical Engineering Technician
107.	[redacted]	Electrical Engineering Technologist
108.	[redacted]	Human Resources Management
109.	[redacted]	Human Resources Management
110.	[redacted]	Human Resources Management
111.	[redacted]	Electrical Engineering Technology
112.	[redacted]	Electrical Engineering Technology
113.	[redacted]	Electrical Engineering Technology
114.	[redacted]	Electrical Engineering Technology
115.	[redacted]	Electrical Engineering Technology
116.	[redacted]	Electrical Engineering Technology
117.	[redacted]	Electrical Engineering Technology
118.	[redacted]	Electrical Engineering Technology
119.	[redacted]	Electrical Engineering Technology
120.	[redacted]	Electrical Engineering Technology
121.	[redacted]	Electrical Engineering Technician
122.	[redacted]	Electrical Engineering Technology
123.	[redacted]	Electrical Engineering
124.	[redacted]	Electrical Engineering
125.	[redacted]	Computer Science
126.	[redacted]	Computer Science
127.	[redacted]	Computer Science
128.	[redacted]	Electrical Engineering
129.	[redacted]	Electrical Engineering
130.	[redacted]	Electrical Engineering
131.	[redacted]	Electrical Engineering
132.	[redacted]	Marketing Management
133.	[redacted]	Marketing Management

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	[redacted]	Accounting
135.		Accounting
136.		Electrical Engineering
137.		Electrical Engineering
138.		Electrical and Biomedical Engineering
139.		Electrical and Biomedical Engineering
140.		Software Engineering and Management
141.		Electrical Engineering
142.		Electrical Engineering
143.		Energy Engineering Technology
144.		Accounting
145.		Accounting
146.		Engineering Physics
147.		Electrical Engineering
148.		Electrical Engineering
149.		Electrical Engineering
150.		Electrical Engineering
151.		Electrical Engineering
152.		Electrical Engineering
153.		Accounting
154.		Finance
155.		Finance
156.		Computer Engineering
157.		Computer Engineering
158.		Energy Engineering Technology
159.		Energy Engineering Technology
160.		Energy Engineering Technology
161.		Electrical Engineering
162.		Electrical Engineering
163.		Energy Engineering
164.		Electrical Engineering
165.		Electrical Engineering
166.	[redacted]	Mechanical Engineering
167.	[redacted]	Mechanical Engineering
168.	[redacted]	Electrical Engineering
169.	[redacted]	Electrical Engineering
170.	[redacted]	Electrical Engineering
171.	[redacted]	Electrical Engineering
172.	[redacted]	Energy Engineering Technology
173.	[redacted]	Civil Engineering Infrastructure Technology
174.	[redacted]	Civil Engineering Infrastructure Technology
175.	[redacted]	Civil Engineering Infrastructure Technology
176.	[redacted]	Electrical Engineering
177.	[redacted]	Electrical Engineering
178.	[redacted]	Accounting
179.	[redacted]	Accounting
180.	[redacted]	Electrical and Biomedical Engineering
181.	[redacted]	Electrical and Biomedical Engineering
182.	[redacted]	Commerce
183.	[redacted]	Commerce
184.	[redacted]	Electrical Engineering
185.	[redacted]	Electrical Engineering
186.	[redacted]	Finance
187.	[redacted]	Finance
188.	[redacted]	Energy Engineering Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.		Energy Engineering Technology
190.	[redacted]	Energy Engineering Technology
191.	[redacted]	Electrical Engineering
192.	[redacted]	Electrical and Biomedical Engineering
193.	[redacted]	Electrical and Biomedical Engineering
194.	[redacted]	Electrical and Biomedical Engineering
195.	[redacted]	Electrical Engineering
196.	[redacted]	Electrical Engineering
197.	[redacted]	Electrical Engineering
198.	[redacted]	Electrical and Biomedical Engineering
199.	[redacted]	Electrical Engineering
200.	[redacted]	Electrical Engineering
201.	[redacted]	Energy Engineering Technology
202.	[redacted]	Electrical Engineering
203.	[redacted]	Electrical Engineering
204.	[redacted]	Electrical Engineering
205.	[redacted]	Electrical Engineering
206.	[redacted]	Electrical and Biomedical Engineering
207.	[redacted]	Electrical and Biomedical Engineering
208.	[redacted]	Software Engineering
209.	[redacted]	Software Engineering
210.	[redacted]	Electrical Engineering
211.	[redacted]	Electrical Engineering
212.	[redacted]	Electrical Engineering
213.	[redacted]	Electrical Engineering
214.	[redacted]	Computer Science
215.	[redacted]	Electrical Engineering
216.	[redacted]	Electrical Engineering
217.	[redacted]	Business
218.	[redacted]	Business
219.	[redacted]	Business
220.	[redacted]	Electrical Engineering
221.	[redacted]	Energy Systems Engineering Technology
222.	[redacted]	Energy Systems Engineering Technology
223.	[redacted]	Energy Systems Engineering Technology
224.	[redacted]	Energy Systems Engineering Technology
225.	[redacted]	Electrical Engineering Technology
226.	[redacted]	Electrical Engineering Technology
227.	[redacted]	Electrical Engineering Technology
228.	[redacted]	Electrical Engineering Technology
229.	[redacted]	Energy Systems Engineering Technology
230.	[redacted]	Electrical Engineering Technology
231.	[redacted]	Electrical Engineering Technology
232.	[redacted]	Electrical Engineering Technology
233.	[redacted]	Electrical Engineering Technology
234.	[redacted]	Electrical Engineering Technology
235.	[redacted]	Electrical Engineering Technology
236.	[redacted]	Electrical Engineering Technology
237.	[redacted]	Electrical Engineering Technology
238.	[redacted]	Energy Systems Engineering Technology
239.	[redacted]	Energy Systems Engineering Technology
240.	[redacted]	Energy Systems Engineering Technology
241.	[redacted]	Electrical Engineering Technology
242.	[redacted]	Electrical Engineering Technology
243.	[redacted]	Electrical Engineering Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	[redacted]	Energy Systems Engineering Technology
245.	[redacted]	Electrical Engineering Technology
246.	[redacted]	Electrical Engineering Technology
247.	[redacted]	Electrical Engineering
248.	[redacted]	Electrical Engineering
249.	[redacted]	Environmental Biology
250.	[redacted]	Environmental Biology
251.	[redacted]	Electrical Engineering
252.	[redacted]	Electrical Engineering
253.	[redacted]	Electrical Engineering
254.	[redacted]	Electrical Engineering
255.	[redacted]	Electrical Engineering
256.	[redacted]	Electrical Engineering
257.	[redacted]	Electrical Engineering
258.	[redacted]	Electrical Engineering
259.	[redacted]	Electrical Engineering
260.	[redacted]	Electrical Engineering
261.	[redacted]	Electrical Engineering
262.	[redacted]	Electrical Engineering
263.	[redacted]	Business Technology Management
264.	[redacted]	Business Technology Management
265.	[redacted]	Business Management
266.	[redacted]	Chemical Engineering
267.	[redacted]	Chemical Engineering
268.	[redacted]	Electrical Engineering
269.	[redacted]	Electrical Engineering
270.	[redacted]	Computer Science
271.	[redacted]	Computer Science
272.	[redacted]	Electrical Engineering
273.	[redacted]	Electrical Engineering
274.	[redacted]	Geographic Analysis
275.	[redacted]	Geographic Analysis
276.	[redacted]	Electrical Engineering
277.	[redacted]	Electrical Engineering
278.	[redacted]	Electrical Engineering
279.	[redacted]	Electrical Engineering
280.	[redacted]	Electrical Engineering
281.	[redacted]	Electrical Engineering
282.	[redacted]	Electrical Engineering
283.	[redacted]	Electrical Engineering
284.	[redacted]	Electrical Engineering
285.	[redacted]	Electrical Engineering
286.	[redacted]	Environmental and Urban Sustainability
287.	[redacted]	Environmental and Urban Sustainability
288.	[redacted]	Electrical Engineering
289.	[redacted]	Electrical Engineering
290.	[redacted]	Occupational Health and Safety
291.	[redacted]	Occupational Health and Safety
292.	[redacted]	Public Relations
293.	[redacted]	Marketing Management
294.	[redacted]	Marketing Management
295.	[redacted]	Real Estate and Housing
296.	[redacted]	Real Estate and Housing
297.	[redacted]	Real Estate and Housing
298.	[redacted]	Real Estate and Housing

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.	[redacted]	Real Estate and Housing
300.	[redacted]	Finance
301.	[redacted]	Electrical Engineering
302.	[redacted]	Electrical Engineering
303.	[redacted]	Electrical Engineering
304.	[redacted]	Computer Science
305.	[redacted]	Computer Science
306.	[redacted]	Electrical Engineering
307.	[redacted]	Electrical Engineering
308.	[redacted]	Electrical Engineering
309.	[redacted]	Electrical Engineering
310.	[redacted]	Electrical Engineering
311.	[redacted]	Electrical Engineering
312.	[redacted]	Electrical Engineering
313.	[redacted]	Electrical Engineering
314.	[redacted]	Electrical Engineering
315.	[redacted]	Electrical Engineering
316.	[redacted]	Electrical Engineering
317.	[redacted]	Electrical Engineering
318.	[redacted]	Accounting
319.	[redacted]	Accounting
320.	[redacted]	Accounting
321.	[redacted]	Electrical Engineering
322.	[redacted]	Electrical Engineering
323.	[redacted]	Electrical Engineering
324.	[redacted]	Electrical Engineering
325.	[redacted]	Electrical Engineering
326.	[redacted]	Electrical Engineering
327.	[redacted]	Materials Science & Engineering
328.	[redacted]	Materials Science & Engineering
329.	[redacted]	Mechanical Engineering
330.	[redacted]	Mechanical Engineering
331.	[redacted]	Finance
332.	[redacted]	Electrical Engineering
333.	[redacted]	Electrical Engineering
334.	[redacted]	Accounting
335.	[redacted]	Accounting
336.	[redacted]	Electrical Engineering
337.	[redacted]	Electrical Engineering
338.	[redacted]	Electrical Engineering
339.	[redacted]	Electrical Engineering
340.	[redacted]	Mechanical and Electrical Engineering
341.	[redacted]	Mechanical and Electrical Engineering
342.	[redacted]	Mechanical and Electrical Engineering
343.	[redacted]	Civil Engineering
344.	[redacted]	Civil Engineering
345.	[redacted]	Mechanical Engineering
346.	[redacted]	Mechanical Engineering
347.	[redacted]	Elecrical Engineering
348.	[redacted]	Elecrical Engineering
349.	[redacted]	Electrical and Computer Engineering
350.	[redacted]	Electrical and Computer Engineering
351.	[redacted]	Electrical and Computer Engineering
352.	[redacted]	Electrical Engineering
353.	[redacted]	Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
354.	[redacted]	Mechanical Engineering
355.	[redacted]	Mechanical Engineering
356.	[redacted]	Mechanical Engineering
357.	[redacted]	Electrical Engineering
358.	[redacted]	Electrical Engineering
359.	[redacted]	Electrical Engineering
360.	[redacted]	Energy Systems Design Engineering
361.	[redacted]	Electrical Engineering
362.	[redacted]	Electrical Engineering
363.	[redacted]	Electrical Engineering
364.	[redacted]	Computer Engineering
365.	[redacted]	Computer Engineering
366.	[redacted]	Electrical Engineering
367.	[redacted]	Electrical Engineering
368.	[redacted]	Electrical Engineering
369.	[redacted]	Electrical Engineering
370.	[redacted]	Electrical Engineering
371.	[redacted]	Electrical and Computer Engineering
372.	[redacted]	Electrical and Computer Engineering
373.	[redacted]	Electrical Engineering
374.	[redacted]	Electrical Engineering
375.	[redacted]	Business Administration
376.	[redacted]	Business Administration
377.	[redacted]	Electrical and Computer Engineering
378.	[redacted]	Electrical and Computer Engineering
379.	[redacted]	Electrical and Computer Engineering
380.	[redacted]	Aerospace Engineering
381.	[redacted]	Aerospace Engineering
382.	[redacted]	Electrical Engineering
383.	[redacted]	Electrical Engineering
384.	[redacted]	Electrical and Computer Engineering
385.	[redacted]	Electrical and Computer Engineering
386.	[redacted]	Electrical and Computer Engineering
387.	[redacted]	Engineering Sciences
388.	[redacted]	Engineering Sciences
389.	[redacted]	Civil Engineering
390.	[redacted]	Civil Engineering
391.	[redacted]	Electrical and Computer Engineering
392.	[redacted]	Electrical and Computer Engineering
393.	[redacted]	Mechanical Engineering
394.	[redacted]	Mechanical Engineering
395.	[redacted]	Mechanical Engineering
396.	[redacted]	Energy Systems Engineering
397.	[redacted]	Energy Systems Engineering
398.	[redacted]	Electrical and Computer Engineering
399.	[redacted]	Electrical and Computer Engineering
400.	[redacted]	Electrical and Computer Engineering
401.	[redacted]	Management and Finance
402.	[redacted]	Electrical Engineering
403.	[redacted]	Electrical Engineering
404.	[redacted]	Chemical Engineering
405.	[redacted]	Chemical Engineering
406.	[redacted]	Mechanical Engineering
407.	[redacted]	Electrical Engineering
408.	[redacted]	Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
409.	[redacted]	Environmental Management
410.	[redacted]	Environmental Management
411.	[redacted]	Environmental Studies
412.	[redacted]	Accounting and Finance
413.	[redacted]	Electrical Engineering
414.	[redacted]	Environmental Studies
415.	[redacted]	Environmental Studies
416.	[redacted]	Chemical Engineering
417.	[redacted]	Economics
418.	[redacted]	Economics
419.	[redacted]	Physics & Astronomy
420.	[redacted]	Electrical Engineering
421.	[redacted]	Geography and Environmental Management
422.	[redacted]	Business Speech Communication
423.	[redacted]	Business Speech Communication
424.	[redacted]	Geography and Environmental Management
425.	[redacted]	Urban Planning
426.	[redacted]	Electrical Engineering
427.	[redacted]	Electrical Engineering
428.	[redacted]	Mechanical Engineering
429.	[redacted]	Business Administration
430.	[redacted]	Electrical Engineering
431.	[redacted]	Electrical Engineering
432.	[redacted]	Electrical Engineering
433.	[redacted]	Electrical Engineering
434.	[redacted]	Electrical Engineering
435.	[redacted]	Electrical Engineering
436.	[redacted]	Finance
437.	[redacted]	Finance
438.	[redacted]	Electrical Engineering
439.	[redacted]	Electrical Engineering
440.	[redacted]	Electrical Engineering
441.	[redacted]	Electrical Engineering
442.	[redacted]	Electrical Engineering
443.	[redacted]	Electrical Engineering
444.	[redacted]	Electrical Engineering
445.	[redacted]	Electrical Engineering
446.	[redacted]	Electrical Engineering
447.	[redacted]	Electrical Engineering
448.	[redacted]	Business Technology Management
449.	[redacted]	Business Administration
450.	[redacted]	Business Administration
451.	[redacted]	Computer Engineering
452.	[redacted]	Accounting
453.	[redacted]	Accounting
454.	[redacted]	Electrical Engineering
455.	[redacted]	Electrical Engineering

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Co-op 1	2016-01-01	2016-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
2.	Co-op 2	2016-05-01	2016-08-31
3.	Co-op 3	2016-04-28	2016-08-31
4.	Co-op 4	2016-01-04	2016-04-30
5.	Co-op 5	2016-05-01	2016-09-02
6.	Co-op 6	2016-08-29	2016-12-23
7.	Co-op 7	2016-05-02	2016-08-31
8.	Co-op 8	2016-09-01	2016-12-31
9.	Co-op 9	2016-01-04	2016-04-30
10.	Co-op 10	2016-05-01	2016-08-31
11.	Co-op 11	2016-09-01	2016-12-30
12.	Co-op 12	2016-01-01	2016-04-30
13.	Co-op 13	2016-05-01	2016-08-31
14.	Co-op 14	2016-09-01	2016-12-30
15.	Co-op 15	2016-08-22	2016-12-31
16.	Co-op 16	2016-01-04	2016-04-30
17.	Co-op 17	2016-05-01	2016-08-31
18.	Co-op 18	2016-09-01	2016-12-31
19.	Co-op 19	2016-01-18	2016-04-30
20.	Co-op 20	2016-05-01	2016-08-26
21.	Co-op 21	2016-01-01	2016-04-30
22.	Co-op 22	2016-05-01	2016-08-26
23.	Co-op 23	2016-04-21	2016-08-31
24.	Co-op 24	2016-09-01	2016-12-31
25.	Co-op 25	2016-01-01	2016-05-18
26.	Co-op 26	2016-01-14	2016-04-30
27.	Co-op 27	2016-05-01	2016-08-31
28.	Co-op 28	2016-09-01	2016-12-31
29.	Co-op 29	2016-01-01	2016-05-02
30.	Co-op 30	2016-01-01	2016-05-06
31.	Co-op 31	2016-01-01	2016-04-30
32.	Co-op 32	2016-05-01	2016-08-31
33.	Co-op 33	2016-01-01	2016-04-30
34.	Co-op 34	2016-05-01	2016-08-31
35.	Co-op 35	2016-05-05	2016-08-31
36.	Co-op 36	2016-09-06	2016-12-31
37.	Co-op 37	2016-01-04	2016-04-29
38.	Co-op 38	2016-05-01	2016-08-31
39.	Co-op 39	2016-05-01	2016-08-31
40.	Co-op 40	2016-01-01	2016-04-29
41.	Co-op 41	2016-05-02	2016-09-02
42.	Co-op 42	2016-09-06	2016-12-16
43.	Co-op 43	2016-01-01	2016-04-29
44.	Co-op 44	2016-01-01	2016-04-29
45.	Co-op 45	2016-04-25	2016-09-02
46.	Co-op 46	2016-04-25	2016-09-02
47.	Co-op 47	2016-01-05	2016-04-29
48.	Co-op 48	2016-09-06	2016-12-16
49.	Co-op 49	2016-01-01	2016-05-02
50.	Co-op 50	2016-01-01	2016-04-30
51.	Co-op 51	2016-09-01	2016-12-16
52.	Co-op 52	2016-01-04	2016-04-30
53.	Co-op 53	2016-05-01	2016-08-31
54.	Co-op 54	2016-01-04	2016-05-06
55.	Co-op 55	2016-01-07	2016-04-27

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
56.	Co-op 56	2016-01-01	2016-04-30
57.	Co-op 57	2016-09-01	2016-12-16
58.	Co-op 58	2016-05-02	2016-09-02
59.	Co-op 59	2016-05-02	2016-09-02
60.	Co-op 60	2015-12-21	2016-05-06
61.	Co-op 61	2016-09-06	2016-12-06
62.	Co-op 62	2016-09-01	2016-12-31
63.	Co-op 63	2016-01-01	2016-04-30
64.	Co-op 64	2016-05-01	2016-09-02
65.	Co-op 65	2016-01-11	2016-04-30
66.	Co-op 66	2016-05-02	2016-09-02
67.	Co-op 67	2016-05-01	2016-08-31
68.	Co-op 68	2016-09-01	2016-12-16
69.	Co-op 69	2016-01-01	2016-04-30
70.	Co-op 70	2016-09-01	2016-12-30
71.	Co-op 71	2016-08-18	2016-12-23
72.	Co-op 72	2016-04-25	2016-09-02
73.	Co-op 73	2016-05-02	2016-09-02
74.	Co-op 74	2016-09-06	2016-12-16
75.	Co-op 75	2015-12-21	2016-05-06
76.	Co-op 76	2016-09-05	2016-12-22
77.	Co-op 77	2015-12-21	2016-05-06
78.	Co-op 78	2016-09-06	2016-12-22
79.	Co-op 79	2016-01-11	2016-05-07
80.	Co-op 80	2016-01-07	2016-04-27
81.	Co-op 81	2016-01-01	2016-04-29
82.	Co-op 82	2016-01-11	2016-04-29
83.	Co-op 83	2016-01-11	2016-04-30
84.	Co-op 84	2016-05-02	2016-09-02
85.	Co-op 85	2016-01-01	2016-05-06
86.	Co-op 86	2016-09-06	2016-12-16
87.	Co-op 87	2016-01-05	2016-04-30
88.	Co-op 88	2016-05-01	2016-09-02
89.	Co-op 89	2015-12-28	2016-04-30
90.	Co-op 90	2016-09-01	2016-12-30
91.	Co-op 91	2016-01-01	2016-04-29
92.	Co-op 92	2016-09-06	2016-12-16
93.	Co-op 93	2016-08-22	2016-12-30
94.	Co-op 94	2016-09-01	2016-12-31
95.	Co-op 95	2016-09-06	2016-12-16
96.	Co-op 96	2016-01-07	2016-05-03
97.	Co-op 97	2016-01-11	2016-04-29
98.	Co-op 98	2016-01-11	2016-04-29
99.	Co-op 99	2016-01-01	2016-04-30
100.	Co-op 100	2016-08-29	2016-12-30
101.	Co-op 101	2016-05-02	2016-09-02
102.	Co-op 102	2016-09-06	2016-12-31
103.	Co-op 103	2016-09-06	2016-12-16
104.	Co-op 104	2016-01-01	2016-05-06
105.	Co-op 105	2016-08-30	2016-12-31
106.	Co-op 106	2016-05-02	2016-09-02
107.	Co-op 107	2016-09-08	2016-12-31
108.	Co-op 108	2016-04-28	2016-08-31
109.	Co-op 109	2015-12-28	2016-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
110.	Co-op 110	2016-05-01	2016-09-02
111.	Co-op 111	2016-01-11	2016-04-30
112.	Co-op 112	2016-09-01	2016-12-30
113.	Co-op 113	2016-09-06	2016-12-16
114.	Co-op 114	2016-01-04	2016-04-30
115.	Co-op 115	2016-05-01	2016-08-31
116.	Co-op 116	2016-09-01	2016-12-30
117.	Co-op 117	2015-10-15	2016-05-02
118.	Co-op 118	2016-01-01	2016-04-30
119.	Co-op 119	2016-05-01	2016-09-02
120.	Co-op 120	2016-09-06	2016-12-16
121.	Co-op 121	2016-01-11	2016-04-29
122.	Co-op 122	2016-09-06	2016-12-16
123.	Co-op 123	2016-01-01	2016-04-30
124.	Co-op 124	2016-05-01	2016-08-31
125.	Co-op 125	2016-05-05	2016-08-31
126.	Co-op 126	2016-09-01	2016-12-31
127.	Co-op 127	2016-05-02	2016-09-02
128.	Co-op 128	2016-01-01	2016-04-30
129.	Co-op 129	2016-05-01	2016-08-31
130.	Co-op 130	2016-01-01	2016-04-30
131.	Co-op 131	2016-05-01	2016-08-26
132.	Co-op 132	2016-01-07	2016-04-30
133.	Co-op 133	2016-05-01	2016-09-02
134.	Co-op 134	2016-05-02	2016-08-31
135.	Co-op 135	2016-09-01	2016-12-31
136.	Co-op 136	2016-01-01	2016-04-30
137.	Co-op 137	2016-05-01	2016-08-31
138.	Co-op 138	2016-05-05	2016-08-31
139.	Co-op 139	2016-09-01	2016-12-31
140.	Co-op 140	2016-05-05	2016-08-31
141.	Co-op 141	2016-01-01	2016-04-30
142.	Co-op 142	2016-05-01	2016-09-02
143.	Co-op 143	2016-01-01	2016-04-30
144.	Co-op 144	2016-05-09	2016-08-31
145.	Co-op 145	2016-09-01	2016-12-31
146.	Co-op 146	2016-08-02	2016-12-31
147.	Co-op 147	2016-05-02	2016-08-31
148.	Co-op 148	2016-09-01	2016-12-30
149.	Co-op 149	2016-06-27	2016-12-31
150.	Co-op 150	2016-09-06	2016-12-31
151.	Co-op 151	2016-01-01	2016-04-30
152.	Co-op 152	2016-05-01	2016-08-26
153.	Co-op 153	2016-08-22	2016-12-31
154.	Co-op 154	2016-05-05	2016-08-31
155.	Co-op 155	2016-09-01	2016-12-31
156.	Co-op 156	2016-05-05	2016-08-31
157.	Co-op 157	2016-09-01	2016-12-31
158.	Co-op 158	2016-01-14	2016-04-30
159.	Co-op 159	2016-05-01	2016-08-31
160.	Co-op 160	2016-09-01	2016-12-22
161.	Co-op 161	2016-01-01	2016-04-30
162.	Co-op 162	2016-05-01	2016-08-26
163.	Co-op 163	2016-01-01	2016-04-29

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
164.	Co-op 164	2016-09-01	2016-12-31
165.	Co-op 165	2016-09-06	2016-12-31
166.	Co-op 166	2016-01-01	2016-04-30
167.	Co-op 167	2016-05-01	2016-08-31
168.	Co-op 168	2016-01-01	2016-04-30
169.	Co-op 169	2016-05-01	2016-09-02
170.	Co-op 170	2016-01-01	2016-04-30
171.	Co-op 171	2016-05-01	2016-09-02
172.	Co-op 172	2016-01-01	2016-05-11
173.	Co-op 173	2016-01-04	2016-04-30
174.	Co-op 174	2016-05-01	2016-08-31
175.	Co-op 175	2016-09-01	2016-12-28
176.	Co-op 176	2016-05-02	2016-08-31
177.	Co-op 177	2016-09-01	2016-12-31
178.	Co-op 178	2016-05-05	2016-08-31
179.	Co-op 179	2016-09-01	2016-12-31
180.	Co-op 180	2016-01-01	2016-04-30
181.	Co-op 181	2016-05-01	2016-08-19
182.	Co-op 182	2016-05-26	2016-08-31
183.	Co-op 183	2016-09-01	2016-12-31
184.	Co-op 184	2016-05-05	2016-08-31
185.	Co-op 185	2016-09-01	2016-12-31
186.	Co-op 186	2016-01-01	2016-04-30
187.	Co-op 187	2016-05-01	2016-08-26
188.	Co-op 188	2016-01-01	2016-04-30
189.	Co-op 189	2016-05-01	2016-08-31
190.	Co-op 190	2016-09-01	2016-12-28
191.	Co-op 191	2016-09-01	2016-12-31
192.	Co-op 192	2016-01-07	2016-04-30
193.	Co-op 193	2016-05-01	2016-08-31
194.	Co-op 194	2016-09-01	2016-12-31
195.	Co-op 195	2016-01-07	2016-04-30
196.	Co-op 196	2016-05-01	2016-08-31
197.	Co-op 197	2016-09-01	2016-12-22
198.	Co-op 198	2016-05-02	2016-09-02
199.	Co-op 199	2016-05-02	2016-08-31
200.	Co-op 200	2016-09-01	2016-12-31
201.	Co-op 201	2016-01-01	2016-04-29
202.	Co-op 202	2016-01-01	2016-04-30
203.	Co-op 203	2016-05-01	2016-08-26
204.	Co-op 204	2016-01-01	2016-04-30
205.	Co-op 205	2016-05-01	2016-08-26
206.	Co-op 206	2016-05-02	2016-08-31
207.	Co-op 207	2016-09-01	2016-12-31
208.	Co-op 208	2016-05-02	2016-08-31
209.	Co-op 209	2016-09-01	2016-12-31
210.	Co-op 210	2016-05-09	2016-08-31
211.	Co-op 211	2016-09-01	2016-12-31
212.	Co-op 212	2016-01-01	2016-04-30
213.	Co-op 213	2016-05-01	2016-07-29
214.	Co-op 214	2016-08-29	2016-12-31
215.	Co-op 215	2016-01-01	2016-04-30
216.	Co-op 216	2016-05-01	2016-08-26
217.	Co-op 217	2015-08-17	2016-01-01

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
218.	Co-op 218	2016-01-02	2016-04-30
219.	Co-op 219	2016-05-01	2016-09-02
220.	Co-op 220	2016-08-29	2016-12-31
221.	Co-op 221	2016-01-04	2016-04-30
222.	Co-op 222	2016-05-01	2016-08-31
223.	Co-op 223	2016-09-01	2016-12-23
224.	Co-op 224	2016-01-11	2016-04-29
225.	Co-op 225	2016-01-28	2016-05-31
226.	Co-op 226	2016-01-07	2016-04-30
227.	Co-op 227	2016-05-01	2016-08-31
228.	Co-op 228	2016-09-01	2016-12-16
229.	Co-op 229	2016-09-06	2016-12-16
230.	Co-op 230	2016-01-04	2016-04-30
231.	Co-op 231	2016-05-01	2016-08-31
232.	Co-op 232	2016-09-01	2016-12-23
233.	Co-op 233	2015-12-14	2016-04-30
234.	Co-op 234	2016-05-01	2016-08-31
235.	Co-op 235	2016-09-01	2016-12-30
236.	Co-op 236	2016-05-02	2016-09-06
237.	Co-op 237	2016-04-25	2016-09-02
238.	Co-op 238	2016-09-06	2016-12-16
239.	Co-op 239	2016-01-11	2016-04-30
240.	Co-op 240	2016-05-01	2016-09-02
241.	Co-op 241	2016-09-06	2016-12-31
242.	Co-op 242	2016-05-02	2016-09-02
243.	Co-op 243	2016-04-21	2016-08-31
244.	Co-op 244	2016-01-01	2016-04-29
245.	Co-op 245	2016-01-11	2016-04-30
246.	Co-op 246	2016-05-01	2016-09-02
247.	Co-op 247	2016-05-02	2016-08-31
248.	Co-op 248	2016-09-01	2016-12-31
249.	Co-op 249	2016-05-05	2016-08-31
250.	Co-op 250	2016-09-01	2016-12-31
251.	Co-op 251	2015-08-24	2016-01-01
252.	Co-op 252	2016-01-02	2016-04-30
253.	Co-op 253	2016-05-01	2016-09-02
254.	Co-op 254	2016-05-02	2016-08-31
255.	Co-op 255	2016-09-01	2016-12-31
256.	Co-op 256	2015-08-20	2016-01-01
257.	Co-op 257	2016-01-02	2016-04-30
258.	Co-op 258	2016-05-01	2016-08-25
259.	Co-op 259	2016-01-01	2016-04-30
260.	Co-op 260	2016-05-01	2016-08-31
261.	Co-op 261	2016-05-05	2016-08-31
262.	Co-op 262	2016-09-01	2016-12-31
263.	Co-op 263	2016-05-02	2016-08-31
264.	Co-op 264	2016-09-01	2016-12-23
265.	Co-op 265	2016-04-25	2016-09-02
266.	Co-op 266	2016-01-01	2016-04-30
267.	Co-op 267	2016-05-01	2016-09-02
268.	Co-op 268	2016-05-02	2016-08-31
269.	Co-op 269	2016-09-01	2016-12-31
270.	Co-op 270	2016-05-02	2016-08-31
271.	Co-op 271	2016-09-01	2016-12-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
272.	Co-op 272	2016-05-02	2016-08-31
273.	Co-op 273	2016-09-01	2016-12-31
274.	Co-op 274	2016-01-04	2016-04-30
275.	Co-op 275	2016-05-01	2016-08-31
276.	Co-op 276	2016-05-02	2016-08-31
277.	Co-op 277	2016-09-01	2016-12-31
278.	Co-op 278	2015-09-01	2016-01-01
279.	Co-op 279	2016-01-02	2016-04-30
280.	Co-op 280	2016-05-01	2016-08-31
281.	Co-op 281	2016-05-02	2016-08-31
282.	Co-op 282	2016-09-01	2016-12-31
283.	Co-op 283	2015-09-08	2016-01-01
284.	Co-op 284	2016-01-02	2016-04-30
285.	Co-op 285	2016-05-01	2016-09-02
286.	Co-op 286	2016-05-05	2016-08-31
287.	Co-op 287	2016-09-01	2016-12-31
288.	Co-op 288	2016-05-05	2016-08-31
289.	Co-op 289	2016-09-01	2016-12-31
290.	Co-op 290	2016-01-01	2016-04-30
291.	Co-op 291	2016-05-01	2016-08-26
292.	Co-op 292	2016-09-07	2016-12-23
293.	Co-op 293	2016-05-02	2016-08-31
294.	Co-op 294	2016-09-01	2016-12-30
295.	Co-op 295	2016-05-02	2016-08-31
296.	Co-op 296	2016-09-01	2016-12-23
297.	Co-op 297	2016-05-02	2016-08-26
298.	Co-op 298	2016-01-04	2016-04-30
299.	Co-op 299	2016-05-01	2016-08-26
300.	Co-op 300	2016-08-29	2016-12-31
301.	Co-op 301	2016-09-02	2016-12-31
302.	Co-op 302	2016-01-01	2016-04-30
303.	Co-op 303	2016-05-01	2016-09-07
304.	Co-op 304	2016-01-01	2016-04-30
305.	Co-op 305	2016-05-01	2016-08-31
306.	Co-op 306	2016-01-01	2016-04-30
307.	Co-op 307	2016-05-01	2016-09-21
308.	Co-op 308	2016-01-01	2016-04-30
309.	Co-op 309	2016-05-01	2016-08-31
310.	Co-op 310	2016-01-07	2016-04-30
311.	Co-op 311	2016-05-01	2016-08-26
312.	Co-op 312	2016-01-04	2016-04-30
313.	Co-op 313	2016-05-01	2016-08-31
314.	Co-op 314	2016-09-01	2016-12-23
315.	Co-op 315	2016-01-04	2016-04-30
316.	Co-op 316	2016-05-01	2016-08-31
317.	Co-op 317	2016-09-01	2016-12-23
318.	Co-op 318	2015-09-08	2016-01-01
319.	Co-op 319	2016-01-02	2016-04-30
320.	Co-op 320	2016-05-01	2016-08-31
321.	Co-op 321	2016-01-01	2016-04-30
322.	Co-op 322	2016-05-01	2016-08-26
323.	Co-op 323	2016-01-01	2016-04-25
324.	Co-op 324	2016-05-02	2016-08-31
325.	Co-op 325	2016-05-05	2016-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
326.	Co-op 326	2016-09-01	2016-12-31
327.	Co-op 327	2016-01-01	2016-04-30
328.	Co-op 328	2016-05-01	2016-08-31
329.	Co-op 329	2016-05-05	2016-08-31
330.	Co-op 330	2016-09-01	2016-12-31
331.	Co-op 331	2016-08-29	2016-12-31
332.	Co-op 332	2016-05-02	2016-08-31
333.	Co-op 333	2016-09-01	2016-12-31
334.	Co-op 334	2016-01-01	2016-04-30
335.	Co-op 335	2016-05-01	2016-08-27
336.	Co-op 336	2016-01-01	2016-04-30
337.	Co-op 337	2016-05-01	2016-09-02
338.	Co-op 338	2016-05-02	2016-08-31
339.	Co-op 339	2016-09-01	2016-12-31
340.	Co-op 340	2015-08-13	2016-01-01
341.	Co-op 341	2016-01-02	2016-04-30
342.	Co-op 342	2016-05-01	2016-08-25
343.	Co-op 343	2016-01-01	2016-04-30
344.	Co-op 344	2016-05-01	2016-08-17
345.	Co-op 345	2016-05-05	2016-08-31
346.	Co-op 346	2016-09-01	2016-12-31
347.	Co-op 347	2016-05-05	2016-08-31
348.	Co-op 348	2016-09-01	2016-12-31
349.	Co-op 349	2015-09-10	2016-01-01
350.	Co-op 350	2016-01-02	2016-04-30
351.	Co-op 351	2016-05-01	2016-08-31
352.	Co-op 352	2016-05-05	2016-08-31
353.	Co-op 353	2016-09-01	2016-12-31
354.	Co-op 354	2015-09-08	2016-01-01
355.	Co-op 355	2016-01-02	2016-04-30
356.	Co-op 356	2016-05-01	2016-08-31
357.	Co-op 357	2015-09-08	2016-01-01
358.	Co-op 358	2016-01-02	2016-04-30
359.	Co-op 359	2016-05-01	2016-08-18
360.	Co-op 360	2016-01-01	2016-05-04
361.	Co-op 361	2016-01-01	2016-04-30
362.	Co-op 362	2016-05-01	2016-08-31
363.	Co-op 363	2016-01-01	2016-05-04
364.	Co-op 364	2016-05-06	2016-08-31
365.	Co-op 365	2016-09-01	2016-12-31
366.	Co-op 366	2016-05-02	2016-08-31
367.	Co-op 367	2016-09-01	2016-12-31
368.	Co-op 368	2015-09-10	2016-01-01
369.	Co-op 369	2016-01-02	2016-04-30
370.	Co-op 370	2016-05-01	2016-08-31
371.	Co-op 371	2016-05-02	2016-08-31
372.	Co-op 372	2016-09-01	2016-12-31
373.	Co-op 373	2016-01-01	2016-04-30
374.	Co-op 374	2016-05-01	2016-08-24
375.	Co-op 375	2016-04-25	2016-08-31
376.	Co-op 376	2016-09-01	2016-12-31
377.	Co-op 377	2015-09-07	2016-01-01
378.	Co-op 378	2016-01-02	2016-04-30
379.	Co-op 379	2016-05-01	2016-08-26

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
380.	Co-op 380	2015-10-01	2016-01-01
381.	Co-op 381	2016-01-02	2016-04-20
382.	Co-op 382	2016-05-05	2016-08-31
383.	Co-op 383	2016-09-01	2016-12-31
384.	Co-op 384	2015-08-20	2016-01-01
385.	Co-op 385	2016-01-02	2016-04-30
386.	Co-op 386	2016-05-01	2016-08-31
387.	Co-op 387	2016-05-02	2016-08-31
388.	Co-op 388	2016-09-01	2016-12-31
389.	Co-op 389	2016-05-02	2016-08-31
390.	Co-op 390	2016-09-01	2016-12-31
391.	Co-op 391	2016-01-01	2016-04-30
392.	Co-op 392	2016-05-01	2016-09-02
393.	Co-op 393	2015-09-14	2016-01-01
394.	Co-op 394	2016-01-02	2016-04-30
395.	Co-op 395	2016-05-01	2016-09-02
396.	Co-op 396	2016-05-05	2016-08-31
397.	Co-op 397	2016-09-01	2016-12-31
398.	Co-op 398	2015-08-17	2016-01-01
399.	Co-op 399	2016-01-02	2016-04-30
400.	Co-op 400	2016-05-01	2016-09-02
401.	Co-op 401	2016-09-07	2016-12-31
402.	Co-op 402	2016-04-28	2016-08-31
403.	Co-op 403	2016-09-01	2016-12-31
404.	Co-op 404	2016-05-26	2016-08-31
405.	Co-op 405	2016-09-01	2016-12-31
406.	Co-op 406	2016-01-01	2016-04-29
407.	Co-op 407	2016-01-01	2016-04-30
408.	Co-op 408	2016-05-01	2016-09-02
409.	Co-op 409	2016-05-02	2016-08-31
410.	Co-op 410	2016-09-01	2016-12-30
411.	Co-op 411	2016-09-06	2016-12-23
412.	Co-op 412	2016-01-07	2016-04-27
413.	Co-op 413	2016-01-11	2016-05-11
414.	Co-op 414	2016-05-02	2016-08-31
415.	Co-op 415	2016-09-01	2016-12-30
416.	Co-op 416	2016-01-04	2016-05-04
417.	Co-op 417	2016-01-04	2016-04-30
418.	Co-op 418	2016-05-01	2016-08-31
419.	Co-op 419	2016-01-04	2016-04-29
420.	Co-op 420	2015-12-21	2016-05-06
421.	Co-op 421	2016-04-26	2016-08-31
422.	Co-op 422	2016-01-13	2016-04-30
423.	Co-op 423	2016-05-01	2016-08-26
424.	Co-op 424	2016-05-02	2016-08-12
425.	Co-op 425	2016-01-04	2016-04-29
426.	Co-op 426	2016-08-30	2016-12-23
427.	Co-op 427	2016-05-02	2016-08-31
428.	Co-op 428	2016-09-12	2016-12-23
429.	Co-op 429	2016-05-09	2016-08-31
430.	Co-op 430	2016-08-29	2016-12-23
431.	Co-op 431	2016-01-04	2016-04-29
432.	Co-op 432	2016-01-04	2016-04-30
433.	Co-op 433	2016-05-01	2016-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
434.	Co-op 434	2016-09-01	2016-12-31
435.	Co-op 435	2016-01-01	2016-04-29
436.	Co-op 436	2016-01-01	2016-04-30
437.	Co-op 437	2016-05-01	2016-08-31
438.	Co-op 438	2016-05-09	2016-08-31
439.	Co-op 439	2016-05-03	2016-08-31
440.	Co-op 440	2016-05-02	2016-08-31
441.	Co-op 441	2016-09-01	2016-12-31
442.	Co-op 442	2016-05-02	2016-08-31
443.	Co-op 443	2016-09-01	2016-12-31
444.	Co-op 444	2016-01-01	2016-04-30
445.	Co-op 445	2016-05-01	2016-09-02
446.	Co-op 446	2016-01-01	2016-04-30
447.	Co-op 447	2016-05-01	2016-09-01
448.	Co-op 448	2016-01-01	2016-05-20
449.	Co-op 449	2016-04-25	2016-08-31
450.	Co-op 450	2016-09-01	2016-12-31
451.	Co-op 451	2016-05-02	2016-09-02
452.	Co-op 452	2016-05-09	2016-08-31
453.	Co-op 453	2016-09-01	2016-12-30
454.	Co-op 454	2016-05-02	2016-08-31
455.	Co-op 455	2016-09-01	2016-12-31

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	23,752	25.000 %		17
2.		10.000 %	23,752	25.000 %		17
3.		10.000 %	22,287	25.000 %		17
4.		10.000 %	31,491	25.000 %		17
5.		10.000 %	31,491	25.000 %		18
6.		10.000 %	15,930	25.000 %		17
7.		10.000 %	19,383	25.000 %		17
8.		10.000 %	19,383	25.000 %		17
9.		10.000 %	18,075	25.000 %		17
10.		10.000 %	18,075	25.000 %		17
11.		10.000 %	18,075	25.000 %		17
12.		10.000 %	18,005	25.000 %		17
13.		10.000 %	18,005	25.000 %		17
14.		10.000 %	18,005	25.000 %		17
15.		10.000 %	17,014	25.000 %		19
16.		10.000 %	19,764	25.000 %		17
17.		10.000 %	19,764	25.000 %		17
18.		10.000 %	19,764	25.000 %		17
19.		10.000 %	19,415	25.000 %		15
20.		10.000 %	19,415	25.000 %		17
21.		10.000 %	22,086	25.000 %		17
22.		10.000 %	22,086	25.000 %		17
23.		10.000 %	13,944	25.000 %		18
24.		10.000 %	13,944	25.000 %		17
25.		10.000 %	29,268	25.000 %		19
26.		10.000 %	17,447	25.000 %		15
27.		10.000 %	17,447	25.000 %		17
28.		10.000 %	17,447	25.000 %		17
29.		10.000 %	23,622	25.000 %		17
30.		10.000 %	17,173	25.000 %		18
31.		10.000 %	24,526	25.000 %		17
32.		10.000 %	24,526	25.000 %		17
33.		10.000 %	24,278	25.000 %		17
34.		10.000 %	24,278	25.000 %		17
35.		10.000 %	20,485	25.000 %		16
36.		10.000 %	13,045	25.000 %		16
37.		10.000 %	15,493	25.000 %		17
38.		10.000 %	17,005	25.000 %		17
39.		10.000 %	14,715	25.000 %		17
40.		10.000 %	15,675	25.000 %		17
41.		10.000 %	14,793	25.000 %		18
42.		10.000 %	13,788	25.000 %		14
43.		10.000 %	19,707	25.000 %		17
44.		10.000 %	15,142	25.000 %		17
45.		10.000 %	18,885	25.000 %		19
46.		10.000 %	14,736	25.000 %		19
47.		10.000 %	15,701	25.000 %		16
48.		10.000 %	13,266	25.000 %		14
49.		10.000 %	15,739	25.000 %		17
50.		10.000 %	13,321	25.000 %		17
51.		10.000 %	13,321	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
52.		10.000 %	14,628	25.000 %		17
53.		10.000 %	14,628	25.000 %		17
54.		10.000 %	16,027	25.000 %		18
55.		10.000 %	16,678	25.000 %		15
56.		10.000 %	14,124	25.000 %		17
57.		10.000 %	14,124	25.000 %		15
58.		10.000 %	15,121	25.000 %		18
59.		10.000 %	15,304	25.000 %		18
60.		10.000 %	20,192	25.000 %		20
61.		10.000 %	13,175	25.000 %		12
62.		10.000 %	13,323	25.000 %		17
63.		10.000 %	14,395	25.000 %		17
64.		10.000 %	14,395	25.000 %		18
65.		10.000 %	14,289	25.000 %		16
66.		10.000 %	14,858	25.000 %		18
67.		10.000 %	14,908	25.000 %		17
68.		10.000 %	14,908	25.000 %		15
69.		10.000 %	15,549	25.000 %		17
70.		10.000 %	15,549	25.000 %		17
71.		10.000 %	15,230	25.000 %		18
72.		10.000 %	18,743	25.000 %		19
73.		10.000 %	14,638	25.000 %		18
74.		10.000 %	14,087	25.000 %		14
75.		10.000 %	15,706	25.000 %		20
76.		10.000 %	13,788	25.000 %		15
77.		10.000 %	18,466	25.000 %		20
78.		10.000 %	13,788	25.000 %		14
79.		10.000 %	16,388	25.000 %		17
80.		10.000 %	13,662	25.000 %		15
81.		10.000 %	13,771	25.000 %		17
82.		10.000 %	15,819	25.000 %		16
83.		10.000 %	20,025	25.000 %		16
84.		10.000 %	17,447	25.000 %		18
85.		10.000 %	19,334	25.000 %		18
86.		10.000 %	12,958	25.000 %		14
87.		10.000 %	13,986	25.000 %		16
88.		10.000 %	13,986	25.000 %		18
89.		10.000 %	15,777	25.000 %		18
90.		10.000 %	15,777	25.000 %		17
91.		10.000 %	15,635	25.000 %		17
92.		10.000 %	26,868	25.000 %		14
93.		10.000 %	29,085	25.000 %		19
94.		10.000 %	15,107	25.000 %		17
95.		10.000 %	13,922	25.000 %		14
96.		10.000 %	16,692	25.000 %		16
97.		10.000 %	14,766	25.000 %		16
98.		10.000 %	13,520	25.000 %		16
99.		10.000 %	15,426	25.000 %		17
100.		10.000 %	15,426	25.000 %		18
101.		10.000 %	15,783	25.000 %		18
102.		10.000 %	13,788	25.000 %		16
103.		10.000 %	13,140	25.000 %		14
104.		10.000 %	17,443	25.000 %		18

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
105.		10.000 %	11,473	25.000 %		17
106.		10.000 %	15,048	25.000 %		18
107.		10.000 %	15,388	25.000 %		16
108.		10.000 %	20,723	25.000 %		17
109.		10.000 %	15,231	25.000 %		18
110.		10.000 %	15,231	25.000 %		18
111.		10.000 %	14,750	25.000 %		16
112.		10.000 %	14,750	25.000 %		17
113.		10.000 %	13,363	25.000 %		14
114.		10.000 %	16,133	25.000 %		17
115.		10.000 %	16,133	25.000 %		17
116.		10.000 %	16,133	25.000 %		17
117.		10.000 %	18,675	25.000 %		28
118.		10.000 %	18,460	25.000 %		17
119.		10.000 %	18,460	25.000 %		18
120.		10.000 %	13,140	25.000 %		14
121.		10.000 %	13,317	25.000 %		16
122.		10.000 %	13,140	25.000 %		14
123.		10.000 %	22,240	25.000 %		17
124.		10.000 %	22,240	25.000 %		17
125.		10.000 %	19,730	25.000 %		16
126.		10.000 %	19,730	25.000 %		17
127.		10.000 %	19,017	25.000 %		18
128.		10.000 %	21,449	25.000 %		17
129.		10.000 %	21,449	25.000 %		17
130.		10.000 %	23,030	25.000 %		17
131.		10.000 %	23,030	25.000 %		17
132.		10.000 %	14,596	25.000 %		16
133.		10.000 %	14,596	25.000 %		18
134.		10.000 %	19,383	25.000 %		17
135.		10.000 %	19,383	25.000 %		17
136.		10.000 %	22,469	25.000 %		17
137.		10.000 %	22,469	25.000 %		17
138.		10.000 %	18,569	25.000 %		16
139.		10.000 %	18,569	25.000 %		17
140.		10.000 %	20,432	25.000 %		16
141.		10.000 %	24,033	25.000 %		17
142.		10.000 %	24,033	25.000 %		18
143.		10.000 %	38,571	25.000 %		17
144.		10.000 %	18,623	25.000 %		16
145.		10.000 %	18,623	25.000 %		17
146.		10.000 %	22,878	25.000 %		21
147.		10.000 %	19,266	25.000 %		17
148.		10.000 %	19,266	25.000 %		17
149.		10.000 %	30,141	25.000 %		27
150.		10.000 %	17,621	25.000 %		16
151.		10.000 %	22,800	25.000 %		17
152.		10.000 %	22,800	25.000 %		17
153.		10.000 %	20,268	25.000 %		19
154.		10.000 %	18,880	25.000 %		16
155.		10.000 %	18,880	25.000 %		17
156.		10.000 %	18,762	25.000 %		16
157.		10.000 %	18,762	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
158.		10.000 %	20,425	25.000 %		15
159.		10.000 %	20,425	25.000 %		17
160.		10.000 %	20,425	25.000 %		15
161.		10.000 %	21,629	25.000 %		17
162.		10.000 %	21,629	25.000 %		17
163.		10.000 %	23,047	25.000 %		17
164.		10.000 %	17,453	25.000 %		17
165.		10.000 %	16,981	25.000 %		16
166.		10.000 %	24,575	25.000 %		17
167.		10.000 %	24,575	25.000 %		17
168.		10.000 %	21,623	25.000 %		17
169.		10.000 %	21,623	25.000 %		18
170.		10.000 %	23,398	25.000 %		17
171.		10.000 %	23,398	25.000 %		18
172.		10.000 %	27,057	25.000 %		18
173.		10.000 %	13,558	25.000 %		17
174.		10.000 %	13,558	25.000 %		17
175.		10.000 %	13,558	25.000 %		16
176.		10.000 %	19,383	25.000 %		17
177.		10.000 %	19,383	25.000 %		17
178.		10.000 %	18,816	25.000 %		16
179.		10.000 %	18,816	25.000 %		17
180.		10.000 %	22,940	25.000 %		17
181.		10.000 %	22,940	25.000 %		16
182.		10.000 %	17,104	25.000 %		13
183.		10.000 %	17,104	25.000 %		17
184.		10.000 %	18,762	25.000 %		16
185.		10.000 %	18,762	25.000 %		17
186.		10.000 %	22,789	25.000 %		17
187.		10.000 %	22,789	25.000 %		17
188.		10.000 %	22,113	25.000 %		17
189.		10.000 %	22,113	25.000 %		17
190.		10.000 %	22,113	25.000 %		16
191.		10.000 %	17,099	25.000 %		17
192.		10.000 %	18,305	25.000 %		16
193.		10.000 %	18,305	25.000 %		17
194.		10.000 %	18,305	25.000 %		17
195.		10.000 %	17,783	25.000 %		16
196.		10.000 %	17,783	25.000 %		17
197.		10.000 %	17,783	25.000 %		15
198.		10.000 %	23,069	25.000 %		18
199.		10.000 %	19,383	25.000 %		17
200.		10.000 %	19,383	25.000 %		17
201.		10.000 %	16,265	25.000 %		17
202.		10.000 %	24,047	25.000 %		17
203.		10.000 %	24,047	25.000 %		17
204.		10.000 %	21,783	25.000 %		17
205.		10.000 %	21,783	25.000 %		17
206.		10.000 %	19,255	25.000 %		17
207.		10.000 %	19,255	25.000 %		17
208.		10.000 %	19,524	25.000 %		17
209.		10.000 %	19,524	25.000 %		17
210.		10.000 %	18,430	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
211.		10.000 %	18,430	25.000 %		17
212.		10.000 %	17,561	25.000 %		17
213.		10.000 %	17,561	25.000 %		13
214.		10.000 %	18,196	25.000 %		18
215.		10.000 %	22,127	25.000 %		17
216.		10.000 %	22,127	25.000 %		17
217.		10.000 %	18,039	25.000 %		20
218.		10.000 %	23,326	25.000 %		17
219.		10.000 %	23,326	25.000 %		18
220.		10.000 %	18,196	25.000 %		18
221.		10.000 %	16,311	25.000 %		17
222.		10.000 %	16,311	25.000 %		17
223.		10.000 %	16,311	25.000 %		16
224.		10.000 %	15,996	25.000 %		16
225.		10.000 %	17,331	25.000 %		17
226.		10.000 %	15,392	25.000 %		16
227.		10.000 %	15,392	25.000 %		17
228.		10.000 %	15,392	25.000 %		15
229.		10.000 %	13,716	25.000 %		14
230.		10.000 %	16,075	25.000 %		17
231.		10.000 %	16,075	25.000 %		17
232.		10.000 %	16,075	25.000 %		16
233.		10.000 %	16,729	25.000 %		20
234.		10.000 %	16,729	25.000 %		17
235.		10.000 %	16,729	25.000 %		17
236.		10.000 %	18,041	25.000 %		18
237.		10.000 %	17,809	25.000 %		19
238.		10.000 %	29,366	25.000 %		14
239.		10.000 %	18,960	25.000 %		16
240.		10.000 %	18,960	25.000 %		18
241.		10.000 %	13,140	25.000 %		16
242.		10.000 %	17,392	25.000 %		18
243.		10.000 %	18,904	25.000 %		18
244.		10.000 %	15,777	25.000 %		17
245.		10.000 %	17,446	25.000 %		16
246.		10.000 %	17,446	25.000 %		18
247.		10.000 %	19,181	25.000 %		17
248.		10.000 %	19,181	25.000 %		17
249.		10.000 %	18,644	25.000 %		16
250.		10.000 %	18,644	25.000 %		17
251.		10.000 %	16,845	25.000 %		19
252.		10.000 %	19,905	25.000 %		17
253.		10.000 %	19,905	25.000 %		18
254.		10.000 %	19,196	25.000 %		17
255.		10.000 %	19,196	25.000 %		17
256.		10.000 %	19,732	25.000 %		19
257.		10.000 %	22,494	25.000 %		17
258.		10.000 %	22,494	25.000 %		16
259.		10.000 %	19,667	25.000 %		17
260.		10.000 %	19,667	25.000 %		17
261.		10.000 %	18,580	25.000 %		16
262.		10.000 %	18,580	25.000 %		17
263.		10.000 %	20,041	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
264.		10.000 %	20,041	25.000 %		16
265.		10.000 %	14,123	25.000 %		19
266.		10.000 %	21,368	25.000 %		17
267.		10.000 %	21,368	25.000 %		18
268.		10.000 %	19,485	25.000 %		17
269.		10.000 %	19,485	25.000 %		17
270.		10.000 %	19,383	25.000 %		17
271.		10.000 %	19,383	25.000 %		17
272.		10.000 %	19,383	25.000 %		17
273.		10.000 %	19,383	25.000 %		17
274.		10.000 %	14,628	25.000 %		17
275.		10.000 %	14,628	25.000 %		17
276.		10.000 %	19,678	25.000 %		17
277.		10.000 %	19,678	25.000 %		17
278.		10.000 %	17,771	25.000 %		17
279.		10.000 %	22,948	25.000 %		17
280.		10.000 %	22,948	25.000 %		17
281.		10.000 %	19,990	25.000 %		17
282.		10.000 %	19,990	25.000 %		17
283.		10.000 %	16,813	25.000 %		16
284.		10.000 %	23,404	25.000 %		17
285.		10.000 %	23,404	25.000 %		18
286.		10.000 %	18,880	25.000 %		16
287.		10.000 %	18,880	25.000 %		17
288.		10.000 %	18,757	25.000 %		16
289.		10.000 %	18,757	25.000 %		17
290.		10.000 %	22,708	25.000 %		17
291.		10.000 %	22,708	25.000 %		17
292.		10.000 %	11,660	25.000 %		15
293.		10.000 %	16,969	25.000 %		17
294.		10.000 %	16,969	25.000 %		17
295.		10.000 %	18,057	25.000 %		17
296.		10.000 %	18,057	25.000 %		16
297.		10.000 %	19,521	25.000 %		17
298.		10.000 %	21,034	25.000 %		17
299.		10.000 %	21,034	25.000 %		17
300.		10.000 %	18,196	25.000 %		18
301.		10.000 %	18,038	25.000 %		17
302.		10.000 %	23,593	25.000 %		17
303.		10.000 %	23,593	25.000 %		18
304.		10.000 %	21,688	25.000 %		17
305.		10.000 %	21,688	25.000 %		17
306.		10.000 %	24,712	25.000 %		17
307.		10.000 %	24,712	25.000 %		20
308.		10.000 %	23,157	25.000 %		17
309.		10.000 %	23,157	25.000 %		17
310.		10.000 %	19,230	25.000 %		16
311.		10.000 %	19,230	25.000 %		17
312.		10.000 %	18,549	25.000 %		17
313.		10.000 %	18,549	25.000 %		17
314.		10.000 %	18,549	25.000 %		16
315.		10.000 %	19,059	25.000 %		17
316.		10.000 %	19,059	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
317.		10.000 %	19,059	25.000 %		16
318.		10.000 %	16,813	25.000 %		16
319.		10.000 %	22,928	25.000 %		17
320.		10.000 %	22,928	25.000 %		17
321.		10.000 %	19,638	25.000 %		17
322.		10.000 %	19,638	25.000 %		17
323.		10.000 %	30,265	25.000 %		16
324.		10.000 %	21,484	25.000 %		17
325.		10.000 %	18,691	25.000 %		16
326.		10.000 %	18,691	25.000 %		17
327.		10.000 %	21,978	25.000 %		17
328.		10.000 %	21,978	25.000 %		17
329.		10.000 %	18,691	25.000 %		16
330.		10.000 %	18,691	25.000 %		17
331.		10.000 %	19,328	25.000 %		18
332.		10.000 %	19,181	25.000 %		17
333.		10.000 %	19,181	25.000 %		17
334.		10.000 %	22,809	25.000 %		17
335.		10.000 %	22,809	25.000 %		17
336.		10.000 %	22,340	25.000 %		17
337.		10.000 %	22,340	25.000 %		18
338.		10.000 %	19,181	25.000 %		17
339.		10.000 %	19,181	25.000 %		17
340.		10.000 %	20,958	25.000 %		20
341.		10.000 %	22,281	25.000 %		17
342.		10.000 %	22,281	25.000 %		16
343.		10.000 %	21,035	25.000 %		17
344.		10.000 %	21,035	25.000 %		15
345.		10.000 %	21,546	25.000 %		16
346.		10.000 %	21,546	25.000 %		17
347.		10.000 %	18,644	25.000 %		16
348.		10.000 %	18,644	25.000 %		17
349.		10.000 %	16,346	25.000 %		16
350.		10.000 %	21,202	25.000 %		17
351.		10.000 %	21,202	25.000 %		17
352.		10.000 %	18,880	25.000 %		16
353.		10.000 %	18,880	25.000 %		17
354.		10.000 %	16,813	25.000 %		16
355.		10.000 %	22,928	25.000 %		17
356.		10.000 %	22,928	25.000 %		17
357.		10.000 %	16,813	25.000 %		16
358.		10.000 %	22,118	25.000 %		17
359.		10.000 %	22,118	25.000 %		15
360.		10.000 %	24,248	25.000 %		17
361.		10.000 %	22,669	25.000 %		17
362.		10.000 %	22,669	25.000 %		17
363.		10.000 %	25,498	25.000 %		17
364.		10.000 %	18,880	25.000 %		16
365.		10.000 %	18,880	25.000 %		17
366.		10.000 %	20,571	25.000 %		17
367.		10.000 %	20,571	25.000 %		17
368.		10.000 %	17,363	25.000 %		16
369.		10.000 %	24,591	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
370.		10.000 %	24,591	25.000 %		17
371.		10.000 %	19,021	25.000 %		17
372.		10.000 %	19,021	25.000 %		17
373.		10.000 %	21,868	25.000 %		17
374.		10.000 %	21,868	25.000 %		16
375.		10.000 %	17,466	25.000 %		18
376.		10.000 %	17,466	25.000 %		17
377.		10.000 %	16,813	25.000 %		17
378.		10.000 %	22,071	25.000 %		17
379.		10.000 %	22,071	25.000 %		17
380.		10.000 %	12,818	25.000 %		13
381.		10.000 %	19,396	25.000 %		15
382.		10.000 %	18,526	25.000 %		16
383.		10.000 %	18,526	25.000 %		17
384.		10.000 %	19,131	25.000 %		19
385.		10.000 %	17,273	25.000 %		17
386.		10.000 %	17,273	25.000 %		17
387.		10.000 %	18,001	25.000 %		17
388.		10.000 %	18,001	25.000 %		17
389.		10.000 %	19,383	25.000 %		17
390.		10.000 %	19,383	25.000 %		17
391.		10.000 %	22,686	25.000 %		17
392.		10.000 %	22,686	25.000 %		18
393.		10.000 %	15,856	25.000 %		16
394.		10.000 %	22,441	25.000 %		17
395.		10.000 %	22,441	25.000 %		18
396.		10.000 %	18,880	25.000 %		16
397.		10.000 %	18,880	25.000 %		17
398.		10.000 %	20,468	25.000 %		20
399.		10.000 %	22,256	25.000 %		17
400.		10.000 %	22,256	25.000 %		18
401.		10.000 %	15,566	25.000 %		16
402.		10.000 %	19,641	25.000 %		17
403.		10.000 %	19,641	25.000 %		17
404.		10.000 %	16,750	25.000 %		13
405.		10.000 %	16,750	25.000 %		17
406.		10.000 %	24,267	25.000 %		17
407.		10.000 %	23,793	25.000 %		17
408.		10.000 %	23,793	25.000 %		18
409.		10.000 %	20,203	25.000 %		17
410.		10.000 %	20,203	25.000 %		17
411.		10.000 %	21,429	25.000 %		15
412.		10.000 %	15,896	25.000 %		15
413.		10.000 %	17,907	25.000 %		17
414.		10.000 %	20,465	25.000 %		17
415.		10.000 %	20,465	25.000 %		17
416.		10.000 %	22,498	25.000 %		17
417.		10.000 %	21,608	25.000 %		17
418.		10.000 %	21,608	25.000 %		17
419.		10.000 %	15,317	25.000 %		17
420.		10.000 %	22,357	25.000 %		20
421.		10.000 %	19,932	25.000 %		17
422.		10.000 %	20,392	25.000 %		15

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
423.		10.000 %	20,392	25.000 %		17
424.		10.000 %	17,155	25.000 %		15
425.		10.000 %	20,187	25.000 %		17
426.		10.000 %	20,594	25.000 %		16
427.		10.000 %	22,826	25.000 %		17
428.		10.000 %	17,011	25.000 %		15
429.		10.000 %	14,507	25.000 %		16
430.		10.000 %	15,930	25.000 %		17
431.		10.000 %	19,159	25.000 %		17
432.		10.000 %	19,530	25.000 %		17
433.		10.000 %	19,530	25.000 %		17
434.		10.000 %	19,530	25.000 %		17
435.		10.000 %	24,445	25.000 %		17
436.		10.000 %	28,918	25.000 %		17
437.		10.000 %	28,918	25.000 %		17
438.		10.000 %	22,322	25.000 %		16
439.		10.000 %	18,153	25.000 %		16
440.		10.000 %	19,181	25.000 %		17
441.		10.000 %	19,181	25.000 %		17
442.		10.000 %	19,181	25.000 %		17
443.		10.000 %	19,181	25.000 %		17
444.		10.000 %	22,906	25.000 %		17
445.		10.000 %	22,906	25.000 %		18
446.		10.000 %	23,630	25.000 %		17
447.		10.000 %	23,630	25.000 %		17
448.		10.000 %	21,813	25.000 %		20
449.		10.000 %	16,950	25.000 %		18
450.		10.000 %	16,950	25.000 %		17
451.		10.000 %	21,974	25.000 %		18
452.		10.000 %	18,623	25.000 %		16
453.		10.000 %	18,623	25.000 %		17
454.		10.000 %	20,251	25.000 %		17
455.		10.000 %	20,251	25.000 %		17

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	5,938	3,000	3,000		3,000
2.	5,938	3,000	3,000		3,000
3.	5,572	3,000	3,000		3,000
4.	7,873	3,000	3,000		3,000
5.	7,873	3,000	3,000		3,000
6.	3,983	3,000	3,000		3,000
7.	4,846	3,000	3,000		3,000
8.	4,846	3,000	3,000		3,000
9.	4,519	3,000	3,000		3,000
10.	4,519	3,000	3,000		3,000
11.	4,519	3,000	3,000		3,000
12.	4,501	3,000	3,000		3,000
13.	4,501	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
14.	4,501	3,000	3,000		3,000
15.	4,254	3,000	3,000		3,000
16.	4,941	3,000	3,000		3,000
17.	4,941	3,000	3,000		3,000
18.	4,941	3,000	3,000		3,000
19.	4,854	3,000	3,000		3,000
20.	4,854	3,000	3,000		3,000
21.	5,522	3,000	3,000		3,000
22.	5,522	3,000	3,000		3,000
23.	3,486	3,000	3,000		3,000
24.	3,486	3,000	3,000		3,000
25.	7,317	3,000	3,000		3,000
26.	4,362	3,000	3,000		3,000
27.	4,362	3,000	3,000		3,000
28.	4,362	3,000	3,000		3,000
29.	5,906	3,000	3,000		3,000
30.	4,293	3,000	3,000		3,000
31.	6,132	3,000	3,000		3,000
32.	6,132	3,000	3,000		3,000
33.	6,070	3,000	3,000		3,000
34.	6,070	3,000	3,000		3,000
35.	5,121	3,000	3,000		3,000
36.	3,261	3,000	3,000		3,000
37.	3,873	3,000	3,000		3,000
38.	4,251	3,000	3,000		3,000
39.	3,679	3,000	3,000		3,000
40.	3,919	3,000	3,000		3,000
41.	3,698	3,000	3,000		3,000
42.	3,447	3,000	3,000		3,000
43.	4,927	3,000	3,000		3,000
44.	3,786	3,000	3,000		3,000
45.	4,721	3,000	3,000		3,000
46.	3,684	3,000	3,000		3,000
47.	3,925	3,000	3,000		3,000
48.	3,317	3,000	3,000		3,000
49.	3,935	3,000	3,000		3,000
50.	3,330	3,000	3,000		3,000
51.	3,330	3,000	3,000		3,000
52.	3,657	3,000	3,000		3,000
53.	3,657	3,000	3,000		3,000
54.	4,007	3,000	3,000		3,000
55.	4,170	3,000	3,000		3,000
56.	3,531	3,000	3,000		3,000
57.	3,531	3,000	3,000		3,000
58.	3,780	3,000	3,000		3,000
59.	3,826	3,000	3,000		3,000
60.	5,048	3,000	3,000		3,000
61.	3,294	3,000	3,000		3,000
62.	3,331	3,000	3,000		3,000
63.	3,599	3,000	3,000		3,000
64.	3,599	3,000	3,000		3,000
65.	3,572	3,000	3,000		3,000
66.	3,715	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
67.	3,727	3,000	3,000		3,000
68.	3,727	3,000	3,000		3,000
69.	3,887	3,000	3,000		3,000
70.	3,887	3,000	3,000		3,000
71.	3,808	3,000	3,000		3,000
72.	4,686	3,000	3,000		3,000
73.	3,660	3,000	3,000		3,000
74.	3,522	3,000	3,000		3,000
75.	3,927	3,000	3,000		3,000
76.	3,447	3,000	3,000		3,000
77.	4,617	3,000	3,000		3,000
78.	3,447	3,000	3,000		3,000
79.	4,097	3,000	3,000		3,000
80.	3,416	3,000	3,000		3,000
81.	3,443	3,000	3,000		3,000
82.	3,955	3,000	3,000		3,000
83.	5,006	3,000	3,000		3,000
84.	4,362	3,000	3,000		3,000
85.	4,834	3,000	3,000		3,000
86.	3,240	3,000	3,000		3,000
87.	3,497	3,000	3,000		3,000
88.	3,497	3,000	3,000		3,000
89.	3,944	3,000	3,000		3,000
90.	3,944	3,000	3,000		3,000
91.	3,909	3,000	3,000		3,000
92.	6,717	3,000	3,000		3,000
93.	7,271	3,000	3,000		3,000
94.	3,777	3,000	3,000		3,000
95.	3,481	3,000	3,000		3,000
96.	4,173	3,000	3,000		3,000
97.	3,692	3,000	3,000		3,000
98.	3,380	3,000	3,000		3,000
99.	3,857	3,000	3,000		3,000
100.	3,857	3,000	3,000		3,000
101.	3,946	3,000	3,000		3,000
102.	3,447	3,000	3,000		3,000
103.	3,285	3,000	3,000		3,000
104.	4,361	3,000	3,000		3,000
105.	2,868	3,000	2,868		2,868
106.	3,762	3,000	3,000		3,000
107.	3,847	3,000	3,000		3,000
108.	5,181	3,000	3,000		3,000
109.	3,808	3,000	3,000		3,000
110.	3,808	3,000	3,000		3,000
111.	3,688	3,000	3,000		3,000
112.	3,688	3,000	3,000		3,000
113.	3,341	3,000	3,000		3,000
114.	4,033	3,000	3,000		3,000
115.	4,033	3,000	3,000		3,000
116.	4,033	3,000	3,000		3,000
117.	4,669	3,000	3,000		3,000
118.	4,615	3,000	3,000		3,000
119.	4,615	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
120.	3,285	3,000	3,000		3,000
121.	3,329	3,000	3,000		3,000
122.	3,285	3,000	3,000		3,000
123.	5,560	3,000	3,000		3,000
124.	5,560	3,000	3,000		3,000
125.	4,933	3,000	3,000		3,000
126.	4,933	3,000	3,000		3,000
127.	4,754	3,000	3,000		3,000
128.	5,362	3,000	3,000		3,000
129.	5,362	3,000	3,000		3,000
130.	5,758	3,000	3,000		3,000
131.	5,758	3,000	3,000		3,000
132.	3,649	3,000	3,000		3,000
133.	3,649	3,000	3,000		3,000
134.	4,846	3,000	3,000		3,000
135.	4,846	3,000	3,000		3,000
136.	5,617	3,000	3,000		3,000
137.	5,617	3,000	3,000		3,000
138.	4,642	3,000	3,000		3,000
139.	4,642	3,000	3,000		3,000
140.	5,108	3,000	3,000		3,000
141.	6,008	3,000	3,000		3,000
142.	6,008	3,000	3,000		3,000
143.	9,643	3,000	3,000		3,000
144.	4,656	3,000	3,000		3,000
145.	4,656	3,000	3,000		3,000
146.	5,720	3,000	3,000		3,000
147.	4,817	3,000	3,000		3,000
148.	4,817	3,000	3,000		3,000
149.	7,535	3,000	3,000		3,000
150.	4,405	3,000	3,000		3,000
151.	5,700	3,000	3,000		3,000
152.	5,700	3,000	3,000		3,000
153.	5,067	3,000	3,000		3,000
154.	4,720	3,000	3,000		3,000
155.	4,720	3,000	3,000		3,000
156.	4,691	3,000	3,000		3,000
157.	4,691	3,000	3,000		3,000
158.	5,106	3,000	3,000		3,000
159.	5,106	3,000	3,000		3,000
160.	5,106	3,000	3,000		3,000
161.	5,407	3,000	3,000		3,000
162.	5,407	3,000	3,000		3,000
163.	5,762	3,000	3,000		3,000
164.	4,363	3,000	3,000		3,000
165.	4,245	3,000	3,000		3,000
166.	6,144	3,000	3,000		3,000
167.	6,144	3,000	3,000		3,000
168.	5,406	3,000	3,000		3,000
169.	5,406	3,000	3,000		3,000
170.	5,850	3,000	3,000		3,000
171.	5,850	3,000	3,000		3,000
172.	6,764	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
173.	3,390	3,000	3,000		3,000
174.	3,390	3,000	3,000		3,000
175.	3,390	3,000	3,000		3,000
176.	4,846	3,000	3,000		3,000
177.	4,846	3,000	3,000		3,000
178.	4,704	3,000	3,000		3,000
179.	4,704	3,000	3,000		3,000
180.	5,735	3,000	3,000		3,000
181.	5,735	3,000	3,000		3,000
182.	4,276	3,000	3,000		3,000
183.	4,276	3,000	3,000		3,000
184.	4,691	3,000	3,000		3,000
185.	4,691	3,000	3,000		3,000
186.	5,697	3,000	3,000		3,000
187.	5,697	3,000	3,000		3,000
188.	5,528	3,000	3,000		3,000
189.	5,528	3,000	3,000		3,000
190.	5,528	3,000	3,000		3,000
191.	4,275	3,000	3,000		3,000
192.	4,576	3,000	3,000		3,000
193.	4,576	3,000	3,000		3,000
194.	4,576	3,000	3,000		3,000
195.	4,446	3,000	3,000		3,000
196.	4,446	3,000	3,000		3,000
197.	4,446	3,000	3,000		3,000
198.	5,767	3,000	3,000		3,000
199.	4,846	3,000	3,000		3,000
200.	4,846	3,000	3,000		3,000
201.	4,066	3,000	3,000		3,000
202.	6,012	3,000	3,000		3,000
203.	6,012	3,000	3,000		3,000
204.	5,446	3,000	3,000		3,000
205.	5,446	3,000	3,000		3,000
206.	4,814	3,000	3,000		3,000
207.	4,814	3,000	3,000		3,000
208.	4,881	3,000	3,000		3,000
209.	4,881	3,000	3,000		3,000
210.	4,608	3,000	3,000		3,000
211.	4,608	3,000	3,000		3,000
212.	4,390	3,000	3,000		3,000
213.	4,390	3,000	3,000		3,000
214.	4,549	3,000	3,000		3,000
215.	5,532	3,000	3,000		3,000
216.	5,532	3,000	3,000		3,000
217.	4,510	3,000	3,000		3,000
218.	5,832	3,000	3,000		3,000
219.	5,832	3,000	3,000		3,000
220.	4,549	3,000	3,000		3,000
221.	4,078	3,000	3,000		3,000
222.	4,078	3,000	3,000		3,000
223.	4,078	3,000	3,000		3,000
224.	3,999	3,000	3,000		3,000
225.	4,333	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
226.	3,848	3,000	3,000		3,000
227.	3,848	3,000	3,000		3,000
228.	3,848	3,000	3,000		3,000
229.	3,429	3,000	3,000		3,000
230.	4,019	3,000	3,000		3,000
231.	4,019	3,000	3,000		3,000
232.	4,019	3,000	3,000		3,000
233.	4,182	3,000	3,000		3,000
234.	4,182	3,000	3,000		3,000
235.	4,182	3,000	3,000		3,000
236.	4,510	3,000	3,000		3,000
237.	4,452	3,000	3,000		3,000
238.	7,342	3,000	3,000		3,000
239.	4,740	3,000	3,000		3,000
240.	4,740	3,000	3,000		3,000
241.	3,285	3,000	3,000		3,000
242.	4,348	3,000	3,000		3,000
243.	4,726	3,000	3,000		3,000
244.	3,944	3,000	3,000		3,000
245.	4,362	3,000	3,000		3,000
246.	4,362	3,000	3,000		3,000
247.	4,795	3,000	3,000		3,000
248.	4,795	3,000	3,000		3,000
249.	4,661	3,000	3,000		3,000
250.	4,661	3,000	3,000		3,000
251.	4,211	3,000	3,000		3,000
252.	4,976	3,000	3,000		3,000
253.	4,976	3,000	3,000		3,000
254.	4,799	3,000	3,000		3,000
255.	4,799	3,000	3,000		3,000
256.	4,933	3,000	3,000		3,000
257.	5,624	3,000	3,000		3,000
258.	5,624	3,000	3,000		3,000
259.	4,917	3,000	3,000		3,000
260.	4,917	3,000	3,000		3,000
261.	4,645	3,000	3,000		3,000
262.	4,645	3,000	3,000		3,000
263.	5,010	3,000	3,000		3,000
264.	5,010	3,000	3,000		3,000
265.	3,531	3,000	3,000		3,000
266.	5,342	3,000	3,000		3,000
267.	5,342	3,000	3,000		3,000
268.	4,871	3,000	3,000		3,000
269.	4,871	3,000	3,000		3,000
270.	4,846	3,000	3,000		3,000
271.	4,846	3,000	3,000		3,000
272.	4,846	3,000	3,000		3,000
273.	4,846	3,000	3,000		3,000
274.	3,657	3,000	3,000		3,000
275.	3,657	3,000	3,000		3,000
276.	4,920	3,000	3,000		3,000
277.	4,920	3,000	3,000		3,000
278.	4,443	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
279.	5,737	3,000	3,000		3,000
280.	5,737	3,000	3,000		3,000
281.	4,998	3,000	3,000		3,000
282.	4,998	3,000	3,000		3,000
283.	4,203	3,000	3,000		3,000
284.	5,851	3,000	3,000		3,000
285.	5,851	3,000	3,000		3,000
286.	4,720	3,000	3,000		3,000
287.	4,720	3,000	3,000		3,000
288.	4,689	3,000	3,000		3,000
289.	4,689	3,000	3,000		3,000
290.	5,677	3,000	3,000		3,000
291.	5,677	3,000	3,000		3,000
292.	2,915	3,000	2,915		2,915
293.	4,242	3,000	3,000		3,000
294.	4,242	3,000	3,000		3,000
295.	4,514	3,000	3,000		3,000
296.	4,514	3,000	3,000		3,000
297.	4,880	3,000	3,000		3,000
298.	5,259	3,000	3,000		3,000
299.	5,259	3,000	3,000		3,000
300.	4,549	3,000	3,000		3,000
301.	4,510	3,000	3,000		3,000
302.	5,898	3,000	3,000		3,000
303.	5,898	3,000	3,000		3,000
304.	5,422	3,000	3,000		3,000
305.	5,422	3,000	3,000		3,000
306.	6,178	3,000	3,000		3,000
307.	6,178	3,000	3,000		3,000
308.	5,789	3,000	3,000		3,000
309.	5,789	3,000	3,000		3,000
310.	4,808	3,000	3,000		3,000
311.	4,808	3,000	3,000		3,000
312.	4,637	3,000	3,000		3,000
313.	4,637	3,000	3,000		3,000
314.	4,637	3,000	3,000		3,000
315.	4,765	3,000	3,000		3,000
316.	4,765	3,000	3,000		3,000
317.	4,765	3,000	3,000		3,000
318.	4,203	3,000	3,000		3,000
319.	5,732	3,000	3,000		3,000
320.	5,732	3,000	3,000		3,000
321.	4,910	3,000	3,000		3,000
322.	4,910	3,000	3,000		3,000
323.	7,566	3,000	3,000		3,000
324.	5,371	3,000	3,000		3,000
325.	4,673	3,000	3,000		3,000
326.	4,673	3,000	3,000		3,000
327.	5,495	3,000	3,000		3,000
328.	5,495	3,000	3,000		3,000
329.	4,673	3,000	3,000		3,000
330.	4,673	3,000	3,000		3,000
331.	4,832	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
332.	4,795	3,000	3,000		3,000
333.	4,795	3,000	3,000		3,000
334.	5,702	3,000	3,000		3,000
335.	5,702	3,000	3,000		3,000
336.	5,585	3,000	3,000		3,000
337.	5,585	3,000	3,000		3,000
338.	4,795	3,000	3,000		3,000
339.	4,795	3,000	3,000		3,000
340.	5,240	3,000	3,000		3,000
341.	5,570	3,000	3,000		3,000
342.	5,570	3,000	3,000		3,000
343.	5,259	3,000	3,000		3,000
344.	5,259	3,000	3,000		3,000
345.	5,387	3,000	3,000		3,000
346.	5,387	3,000	3,000		3,000
347.	4,661	3,000	3,000		3,000
348.	4,661	3,000	3,000		3,000
349.	4,087	3,000	3,000		3,000
350.	5,301	3,000	3,000		3,000
351.	5,301	3,000	3,000		3,000
352.	4,720	3,000	3,000		3,000
353.	4,720	3,000	3,000		3,000
354.	4,203	3,000	3,000		3,000
355.	5,732	3,000	3,000		3,000
356.	5,732	3,000	3,000		3,000
357.	4,203	3,000	3,000		3,000
358.	5,530	3,000	3,000		3,000
359.	5,530	3,000	3,000		3,000
360.	6,062	3,000	3,000		3,000
361.	5,667	3,000	3,000		3,000
362.	5,667	3,000	3,000		3,000
363.	6,375	3,000	3,000		3,000
364.	4,720	3,000	3,000		3,000
365.	4,720	3,000	3,000		3,000
366.	5,143	3,000	3,000		3,000
367.	5,143	3,000	3,000		3,000
368.	4,341	3,000	3,000		3,000
369.	6,148	3,000	3,000		3,000
370.	6,148	3,000	3,000		3,000
371.	4,755	3,000	3,000		3,000
372.	4,755	3,000	3,000		3,000
373.	5,467	3,000	3,000		3,000
374.	5,467	3,000	3,000		3,000
375.	4,367	3,000	3,000		3,000
376.	4,367	3,000	3,000		3,000
377.	4,203	3,000	3,000		3,000
378.	5,518	3,000	3,000		3,000
379.	5,518	3,000	3,000		3,000
380.	3,205	3,000	3,000		3,000
381.	4,849	3,000	3,000		3,000
382.	4,632	3,000	3,000		3,000
383.	4,632	3,000	3,000		3,000
384.	4,783	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
385.	4,318	3,000	3,000		3,000
386.	4,318	3,000	3,000		3,000
387.	4,500	3,000	3,000		3,000
388.	4,500	3,000	3,000		3,000
389.	4,846	3,000	3,000		3,000
390.	4,846	3,000	3,000		3,000
391.	5,672	3,000	3,000		3,000
392.	5,672	3,000	3,000		3,000
393.	3,964	3,000	3,000		3,000
394.	5,610	3,000	3,000		3,000
395.	5,610	3,000	3,000		3,000
396.	4,720	3,000	3,000		3,000
397.	4,720	3,000	3,000		3,000
398.	5,117	3,000	3,000		3,000
399.	5,564	3,000	3,000		3,000
400.	5,564	3,000	3,000		3,000
401.	3,892	3,000	3,000		3,000
402.	4,910	3,000	3,000		3,000
403.	4,910	3,000	3,000		3,000
404.	4,188	3,000	3,000		3,000
405.	4,188	3,000	3,000		3,000
406.	6,067	3,000	3,000		3,000
407.	5,948	3,000	3,000		3,000
408.	5,948	3,000	3,000		3,000
409.	5,051	3,000	3,000		3,000
410.	5,051	3,000	3,000		3,000
411.	5,357	3,000	3,000		3,000
412.	3,974	3,000	3,000		3,000
413.	4,477	3,000	3,000		3,000
414.	5,116	3,000	3,000		3,000
415.	5,116	3,000	3,000		3,000
416.	5,625	3,000	3,000		3,000
417.	5,402	3,000	3,000		3,000
418.	5,402	3,000	3,000		3,000
419.	3,829	3,000	3,000		3,000
420.	5,589	3,000	3,000		3,000
421.	4,983	3,000	3,000		3,000
422.	5,098	3,000	3,000		3,000
423.	5,098	3,000	3,000		3,000
424.	4,289	3,000	3,000		3,000
425.	5,047	3,000	3,000		3,000
426.	5,149	3,000	3,000		3,000
427.	5,707	3,000	3,000		3,000
428.	4,253	3,000	3,000		3,000
429.	3,627	3,000	3,000		3,000
430.	3,983	3,000	3,000		3,000
431.	4,790	3,000	3,000		3,000
432.	4,883	3,000	3,000		3,000
433.	4,883	3,000	3,000		3,000
434.	4,883	3,000	3,000		3,000
435.	6,111	3,000	3,000		3,000
436.	7,230	3,000	3,000		3,000
437.	7,230	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
438.	5,581	3,000	3,000		3,000
439.	4,538	3,000	3,000		3,000
440.	4,795	3,000	3,000		3,000
441.	4,795	3,000	3,000		3,000
442.	4,795	3,000	3,000		3,000
443.	4,795	3,000	3,000		3,000
444.	5,727	3,000	3,000		3,000
445.	5,727	3,000	3,000		3,000
446.	5,908	3,000	3,000		3,000
447.	5,908	3,000	3,000		3,000
448.	5,453	3,000	3,000		3,000
449.	4,238	3,000	3,000		3,000
450.	4,238	3,000	3,000		3,000
451.	5,494	3,000	3,000		3,000
452.	4,656	3,000	3,000		3,000
453.	4,656	3,000	3,000		3,000
454.	5,063	3,000	3,000		3,000
455.	5,063	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 1,364,783 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... ________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number
Glendy Cheung	(416) 345-6812

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 843,179,826

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/trade name **405**	C Name of apprentice **410**
1.	403a	General Carpenter	Apprentice 1
2.	434a	Powerline Technician	Apprentice 2
3.	434a	Powerline Technician	Apprentice 3
4.	434a	Powerline Technician	Apprentice 4
5.	434a	Powerline Technician	Apprentice 5
6.	434a	Powerline Technician	Apprentice 6
7.	434a	Powerline Technician	Apprentice 7
8.	434a	Powerline Technician	Apprentice 8
9.	434a	Powerline Technician	Apprentice 9
10.	434a	Powerline Technician	Apprentice 10
11.	434a	Powerline Technician	Apprentice 11
12.	434a	Powerline Technician	Apprentice 12
13.	434a	Powerline Technician	Apprentice 13
14.	434a	Powerline Technician	Apprentice 14
15.	434a	Powerline Technician	Apprentice 15
16.	434a	Powerline Technician	Apprentice 16
17.	309a	Electrician-Construction and Maintenance	Apprentice 17
18.	309a	Electrician-Construction and Maintenance	Apprentice 18
19.	434a	Powerline Technician	Apprentice 19
20.	434a	Powerline Technician	Apprentice 20
21.	434a	Powerline Technician	Apprentice 21
22.	434a	Powerline Technician	Apprentice 22
23.	434a	Powerline Technician	Apprentice 23
24.	434a	Powerline Technician	Apprentice 24
25.	434a	Powerline Technician	Apprentice 25
26.	434a	Powerline Technician	Apprentice 26
27.	434a	Powerline Technician	Apprentice 27

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
28.	434a	Powerline Technician	Apprentice 28
29.	434a	Powerline Technician	Apprentice 29
30.	434a	Powerline Technician	Apprentice 30
31.	434a	Powerline Technician	Apprentice 31
32.	434a	Powerline Technician	Apprentice 32
33.	434a	Powerline Technician	Apprentice 33
34.	434a	Powerline Technician	Apprentice 34
35.	434a	Powerline Technician	Apprentice 35
36.	309a	Electrician-Construction and Maintenance	Apprentice 36
37.	309a	Electrician-Construction and Maintenance	Apprentice 37
38.	309a	Electrician-Construction and Maintenance	Apprentice 38
39.	309a	Electrician-Construction and Maintenance	Apprentice 39
40.	309a	Electrician-Construction and Maintenance	Apprentice 40
41.	309a	Electrician-Construction and Maintenance	Apprentice 41
42.	434a	Powerline Technician	Apprentice 42
43.	403a	General Carpenter	Apprentice 43
44.	434a	Powerline Technician	Apprentice 44
45.	434a	Powerline Technician	Apprentice 45
46.	434a	Powerline Technician	Apprentice 46
47.	434a	Powerline Technician	Apprentice 47
48.	434a	Powerline Technician	Apprentice 48
49.	434a	Powerline Technician	Apprentice 49
50.	434a	Powerline Technician	Apprentice 50
51.	434a	Powerline Technician	Apprentice 51
52.	310t	Truck And Coach Technician	Apprentice 52
53.	310t	Truck And Coach Technician	Apprentice 53
54.	310t	Truck And Coach Technician	Apprentice 54
55.	434a	Powerline Technician	Apprentice 55
56.	434a	Powerline Technician	Apprentice 56
57.	434a	Powerline Technician	Apprentice 57
58.	434a	Powerline Technician	Apprentice 58
59.	434a	Powerline Technician	Apprentice 59
60.	434a	Powerline Technician	Apprentice 60
61.	434a	Powerline Technician	Apprentice 61
62.	434a	Powerline Technician	Apprentice 62
63.	434a	Powerline Technician	Apprentice 63
64.	434a	Powerline Technician	Apprentice 64
65.	434a	Powerline Technician	Apprentice 65
66.	434a	Powerline Technician	Apprentice 66
67.	434a	Powerline Technician	Apprentice 67
68.	309a	Electrician-Construction and Maintenance	Apprentice 68
69.	309a	Electrician-Construction and Maintenance	Apprentice 69
70.	309a	Electrician-Construction and Maintenance	Apprentice 70
71.	309a	Electrician-Construction and Maintenance	Apprentice 71
72.	309a	Electrician-Construction and Maintenance	Apprentice 72
73.	434a	Powerline Technician	Apprentice 73
74.	434a	Powerline Technician	Apprentice 74
75.	309a	Electrician-Construction and Maintenance	Apprentice 75
76.	309a	Electrician-Construction and Maintenance	Apprentice 76
77.	309a	Electrician-Construction and Maintenance	Apprentice 77
78.	309a	Electrician-Construction and Maintenance	Apprentice 78
79.	309a	Electrician-Construction and Maintenance	Apprentice 79
80.	403a	General Carpenter	Apprentice 80
81.	434a	Powerline Technician	Apprentice 81
82.	434a	Powerline Technician	Apprentice 82

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
83.	434a	Powerline Technician	Apprentice 83
84.	434a	Powerline Technician	Apprentice 84
85.	434a	Powerline Technician	Apprentice 85
86.	434a	Powerline Technician	Apprentice 86
87.	434a	Powerline Technician	Apprentice 87
88.	434a	Powerline Technician	Apprentice 88
89.	434a	Powerline Technician	Apprentice 89
90.	309a	Electrician-Construction and Maintenance	Apprentice 90
91.	309a	Electrician-Construction and Maintenance	Apprentice 91
92.	310t	Truck And Coach Technician	Apprentice 92
93.	310t	Truck And Coach Technician	Apprentice 93
94.	310t	Truck And Coach Technician	Apprentice 94
95.	434a	Powerline Technician	Apprentice 95
96.	434a	Powerline Technician	Apprentice 96
97.	434a	Powerline Technician	Apprentice 97
98.	434a	Powerline Technician	Apprentice 98
99.	434a	Powerline Technician	Apprentice 99
100.	434a	Powerline Technician	Apprentice 100
101.	434a	Powerline Technician	Apprentice 101
102.	434a	Powerline Technician	Apprentice 102
103.	434a	Powerline Technician	Apprentice 103
104.	434a	Powerline Technician	Apprentice 104
105.	434a	Powerline Technician	Apprentice 105
106.	434a	Powerline Technician	Apprentice 106
107.	434a	Powerline Technician	Apprentice 107
108.	434a	Powerline Technician	Apprentice 108
109.	434a	Powerline Technician	Apprentice 109
110.	434a	Powerline Technician	Apprentice 110
111.	434a	Powerline Technician	Apprentice 111
112.	434a	Powerline Technician	Apprentice 112
113.	434a	Powerline Technician	Apprentice 113
114.	434a	Powerline Technician	Apprentice 114
115.	434a	Powerline Technician	Apprentice 115
116.	434a	Powerline Technician	Apprentice 116
117.	434a	Powerline Technician	Apprentice 117
118.	434a	Powerline Technician	Apprentice 118
119.	434a	Powerline Technician	Apprentice 119
120.	434a	Powerline Technician	Apprentice 120
121.	434a	Powerline Technician	Apprentice 121
122.	434a	Powerline Technician	Apprentice 122
123.	434a	Powerline Technician	Apprentice 123
124.	434a	Powerline Technician	Apprentice 124
125.	434a	Powerline Technician	Apprentice 125
126.	434a	Powerline Technician	Apprentice 126
127.	309a	Electrician-Construction and Maintenance	Apprentice 127
128.	309a	Electrician-Construction and Maintenance	Apprentice 128
129.	434a	Powerline Technician	Apprentice 129
130.	434a	Powerline Technician	Apprentice 130
131.	434a	Powerline Technician	Apprentice 131
132.	434a	Powerline Technician	Apprentice 132
133.	434a	Powerline Technician	Apprentice 133
134.	434a	Powerline Technician	Apprentice 134
135.	434a	Powerline Technician	Apprentice 135
136.	434a	Powerline Technician	Apprentice 136
137.	434a	Powerline Technician	Apprentice 137

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
138.	434a	Powerline Technician	Apprentice 138
139.	434a	Powerline Technician	Apprentice 139
140.	434a	Powerline Technician	Apprentice 140
141.	434a	Powerline Technician	Apprentice 141
142.	434a	Powerline Technician	Apprentice 142
143.	434a	Powerline Technician	Apprentice 143
144.	434a	Powerline Technician	Apprentice 144
145.	434a	Powerline Technician	Apprentice 145
146.	434a	Powerline Technician	Apprentice 146
147.	434a	Powerline Technician	Apprentice 147
148.	434a	Powerline Technician	Apprentice 148
149.	434a	Powerline Technician	Apprentice 149
150.	434a	Powerline Technician	Apprentice 150
151.	434a	Powerline Technician	Apprentice 151
152.	434a	Powerline Technician	Apprentice 152
153.	434a	Powerline Technician	Apprentice 153
154.	434a	Powerline Technician	Apprentice 154
155.	434a	Powerline Technician	Apprentice 155
156.	434a	Powerline Technician	Apprentice 156
157.	434a	Powerline Technician	Apprentice 157
158.	434a	Powerline Technician	Apprentice 158
159.	434a	Powerline Technician	Apprentice 159
160.	434a	Powerline Technician	Apprentice 160
161.	309a	Electrician-Construction and Maintenance	Apprentice 161
162.	309a	Electrician-Construction and Maintenance	Apprentice 162
163.	309a	Electrician-Construction and Maintenance	Apprentice 163
164.	309a	Electrician-Construction and Maintenance	Apprentice 164
165.	309a	Electrician-Construction and Maintenance	Apprentice 165
166.	309a	Electrician-Construction and Maintenance	Apprentice 166
167.	309a	Electrician-Construction and Maintenance	Apprentice 167
168.	309a	Electrician-Construction and Maintenance	Apprentice 168
169.	309a	Electrician-Construction and Maintenance	Apprentice 169
170.	309a	Electrician-Construction and Maintenance	Apprentice 170
171.	309a	Electrician-Construction and Maintenance	Apprentice 171
172.	309a	Electrician-Construction and Maintenance	Apprentice 172
173.	309a	Electrician-Construction and Maintenance	Apprentice 173
174.	309a	Electrician-Construction and Maintenance	Apprentice 174
175.	309a	Electrician-Construction and Maintenance	Apprentice 175
176.	309a	Electrician-Construction and Maintenance	Apprentice 176
177.	309a	Electrician-Construction and Maintenance	Apprentice 177
178.	309a	Electrician-Construction and Maintenance	Apprentice 178
179.	433a	Industrial Mechanic (Millwright)	Apprentice 179
180.	433a	Industrial Mechanic (Millwright)	Apprentice 180
181.	433a	Industrial Mechanic (Millwright)	Apprentice 181
182.	433a	Industrial Mechanic (Millwright)	Apprentice 182
183.	309a	Electrician-Construction and Maintenance	Apprentice 183
184.	309a	Electrician-Construction and Maintenance	Apprentice 184
185.	309a	Electrician-Construction and Maintenance	Apprentice 185
186.	309a	Electrician-Construction and Maintenance	Apprentice 186
187.	309a	Electrician-Construction and Maintenance	Apprentice 187
188.	309a	Electrician-Construction and Maintenance	Apprentice 188
189.	309a	Electrician-Construction and Maintenance	Apprentice 189
190.	309a	Electrician-Construction and Maintenance	Apprentice 190
191.	309a	Electrician-Construction and Maintenance	Apprentice 191
192.	309a	Electrician-Construction and Maintenance	Apprentice 192

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
193.	309a	Electrician-Construction and Maintenance	Apprentice 193
194.	434a	Powerline Technician	Apprentice 194
195.	434a	Powerline Technician	Apprentice 195
196.	434a	Powerline Technician	Apprentice 196
197.	309a	Electrician-Construction and Maintenance	Apprentice 197
198.	434a	Powerline Technician	Apprentice 198
199.	434a	Powerline Technician	Apprentice 199
200.	434a	Powerline Technician	Apprentice 200
201.	434a	Powerline Technician	Apprentice 201
202.	434a	Powerline Technician	Apprentice 202
203.	434a	Powerline Technician	Apprentice 203
204.	434a	Powerline Technician	Apprentice 204
205.	434a	Powerline Technician	Apprentice 205
206.	434a	Powerline Technician	Apprentice 206
207.	434a	Powerline Technician	Apprentice 207
208.	434a	Powerline Technician	Apprentice 208
209.	434a	Powerline Technician	Apprentice 209
210.	434a	Powerline Technician	Apprentice 210
211.	434a	Powerline Technician	Apprentice 211
212.	309a	Electrician-Construction and Maintenance	Apprentice 212
213.	309a	Electrician-Construction and Maintenance	Apprentice 213
214.	309a	Electrician-Construction and Maintenance	Apprentice 214
215.	309a	Electrician-Construction and Maintenance	Apprentice 215
216.	309a	Electrician-Construction and Maintenance	Apprentice 216
217.	309a	Electrician-Construction and Maintenance	Apprentice 217
218.	309a	Electrician-Construction and Maintenance	Apprentice 218
219.	309a	Electrician-Construction and Maintenance	Apprentice 219
220.	309a	Electrician-Construction and Maintenance	Apprentice 220
221.	309a	Electrician-Construction and Maintenance	Apprentice 221
222.	309a	Electrician-Construction and Maintenance	Apprentice 222
223.	309a	Electrician-Construction and Maintenance	Apprentice 223
224.	309a	Electrician-Construction and Maintenance	Apprentice 224
225.	434a	Powerline Technician	Apprentice 225
226.	434a	Powerline Technician	Apprentice 226
227.	434a	Powerline Technician	Apprentice 227
228.	434a	Powerline Technician	Apprentice 228
229.	434a	Powerline Technician	Apprentice 229
230.	434a	Powerline Technician	Apprentice 230
231.	434a	Powerline Technician	Apprentice 231
232.	434a	Powerline Technician	Apprentice 232
233.	309a	Electrician-Construction and Maintenance	Apprentice 233
234.	309a	Electrician-Construction and Maintenance	Apprentice 234
235.	309a	Electrician-Construction and Maintenance	Apprentice 235
236.	309a	Electrician-Construction and Maintenance	Apprentice 236
237.	309a	Electrician-Construction and Maintenance	Apprentice 237
238.	434a	Powerline Technician	Apprentice 238
239.	310t	Truck And Coach Technician	Apprentice 239
240.	310t	Truck And Coach Technician	Apprentice 240
241.	310t	Truck And Coach Technician	Apprentice 241
242.	310t	Truck And Coach Technician	Apprentice 242
243.	310t	Truck And Coach Technician	Apprentice 243
244.	310t	Truck And Coach Technician	Apprentice 244
245.	310t	Truck And Coach Technician	Apprentice 245
246.	403a	General Carpenter	Apprentice 246
247.	403a	General Carpenter	Apprentice 247

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
248.	434a	Powerline Technician	Apprentice 248
249.	434a	Powerline Technician	Apprentice 249
250.	434a	Powerline Technician	Apprentice 250
251.	434a	Powerline Technician	Apprentice 251
252.	434a	Powerline Technician	Apprentice 252
253.	434a	Powerline Technician	Apprentice 253
254.	434a	Powerline Technician	Apprentice 254
255.	434a	Powerline Technician	Apprentice 255
256.	434a	Powerline Technician	Apprentice 256
257.	434a	Powerline Technician	Apprentice 257
258.	434a	Powerline Technician	Apprentice 258
259.	434a	Powerline Technician	Apprentice 259
260.	434a	Powerline Technician	Apprentice 260
261.	434a	Powerline Technician	Apprentice 261
262.	309a	Electrician-Construction and Maintenance	Apprentice 262
263.	434a	Powerline Technician	Apprentice 263
264.	434a	Powerline Technician	Apprentice 264
265.	434a	Powerline Technician	Apprentice 265
266.	434a	Powerline Technician	Apprentice 266
267.	434a	Powerline Technician	Apprentice 267
268.	434a	Powerline Technician	Apprentice 268
269.	434a	Powerline Technician	Apprentice 269
270.	434a	Powerline Technician	Apprentice 270
271.	434a	Powerline Technician	Apprentice 271
272.	434a	Powerline Technician	Apprentice 272
273.	434a	Powerline Technician	Apprentice 273
274.	434a	Powerline Technician	Apprentice 274
275.	434a	Powerline Technician	Apprentice 275
276.	434a	Powerline Technician	Apprentice 276
277.	434a	Powerline Technician	Apprentice 277
278.	434a	Powerline Technician	Apprentice 278
279.	434a	Powerline Technician	Apprentice 279
280.	434a	Powerline Technician	Apprentice 280
281.	309a	Electrician-Construction and Maintenance	Apprentice 281
282.	309a	Electrician-Construction and Maintenance	Apprentice 282
283.	309a	Electrician-Construction and Maintenance	Apprentice 283
284.	434a	Powerline Technician	Apprentice 284
285.	434a	Powerline Technician	Apprentice 285
286.	434a	Powerline Technician	Apprentice 286
287.	434a	Powerline Technician	Apprentice 287
288.	434a	Powerline Technician	Apprentice 288
289.	434a	Powerline Technician	Apprentice 289
290.	434a	Powerline Technician	Apprentice 290
291.	434a	Powerline Technician	Apprentice 291
292.	434a	Powerline Technician	Apprentice 292
293.	434a	Powerline Technician	Apprentice 293
294.	434a	Powerline Technician	Apprentice 294
295.	434a	Powerline Technician	Apprentice 295
296.	434a	Powerline Technician	Apprentice 296
297.	434a	Powerline Technician	Apprentice 297
298.	434a	Powerline Technician	Apprentice 298
299.	309a	Electrician-Construction and Maintenance	Apprentice 299
300.	309a	Electrician-Construction and Maintenance	Apprentice 300
301.	309a	Electrician-Construction and Maintenance	Apprentice 301
302.	309a	Electrician-Construction and Maintenance	Apprentice 302

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
303.	434a	Powerline Technician	Apprentice 303
304.	434a	Powerline Technician	Apprentice 304
305.	434a	Powerline Technician	Apprentice 305
306.	434a	Powerline Technician	Apprentice 306
307.	434a	Powerline Technician	Apprentice 307
308.	434a	Powerline Technician	Apprentice 308
309.	434a	Powerline Technician	Apprentice 309
310.	434a	Powerline Technician	Apprentice 310
311.	434a	Powerline Technician	Apprentice 311
312.	434a	Powerline Technician	Apprentice 312
313.	434a	Powerline Technician	Apprentice 313
314.	434a	Powerline Technician	Apprentice 314
315.	309a	Electrician-Construction and Maintenance	Apprentice 315
316.	309a	Electrician-Construction and Maintenance	Apprentice 316
317.	434a	Powerline Technician	Apprentice 317
318.	434a	Powerline Technician	Apprentice 318
319.	434a	Powerline Technician	Apprentice 319
320.	434a	Powerline Technician	Apprentice 320
321.	434a	Powerline Technician	Apprentice 321
322.	434a	Powerline Technician	Apprentice 322
323.	434a	Powerline Technician	Apprentice 323
324.	434a	Powerline Technician	Apprentice 324
325.	434a	Powerline Technician	Apprentice 325
326.	434a	Powerline Technician	Apprentice 326
327.	434a	Powerline Technician	Apprentice 327
328.	434a	Powerline Technician	Apprentice 328
329.	434a	Powerline Technician	Apprentice 329
330.	434a	Powerline Technician	Apprentice 330
331.	434a	Powerline Technician	Apprentice 331
332.	434a	Powerline Technician	Apprentice 332
333.	434a	Powerline Technician	Apprentice 333
334.	434a	Powerline Technician	Apprentice 334
335.	434a	Powerline Technician	Apprentice 335
336.	434a	Powerline Technician	Apprentice 336
337.	434a	Powerline Technician	Apprentice 337
338.	434a	Powerline Technician	Apprentice 338
339.	434a	Powerline Technician	Apprentice 339
340.	434a	Powerline Technician	Apprentice 340
341.	434a	Powerline Technician	Apprentice 341
342.	434a	Powerline Technician	Apprentice 342
343.	434a	Powerline Technician	Apprentice 343
344.	434a	Powerline Technician	Apprentice 344
345.	434a	Powerline Technician	Apprentice 345
346.	434a	Powerline Technician	Apprentice 346
347.	309a	Electrician-Construction and Maintenance	Apprentice 347
348.	309a	Electrician-Construction and Maintenance	Apprentice 348
349.	309a	Electrician-Construction and Maintenance	Apprentice 349
350.	309a	Electrician-Construction and Maintenance	Apprentice 350
351.	309a	Electrician-Construction and Maintenance	Apprentice 351
352.	309a	Electrician-Construction and Maintenance	Apprentice 352
353.	309a	Electrician-Construction and Maintenance	Apprentice 353
354.	309a	Electrician-Construction and Maintenance	Apprentice 354
355.	309a	Electrician-Construction and Maintenance	Apprentice 355
356.	309a	Electrician-Construction and Maintenance	Apprentice 356
357.	309a	Electrician-Construction and Maintenance	Apprentice 357

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
358.	309a	Electrician-Construction and Maintenance	Apprentice 358
359.	309a	Electrician-Construction and Maintenance	Apprentice 359
360.	309a	Electrician-Construction and Maintenance	Apprentice 360
361.	309a	Electrician-Construction and Maintenance	Apprentice 361
362.	309a	Electrician-Construction and Maintenance	Apprentice 362
363.	309a	Electrician-Construction and Maintenance	Apprentice 363
364.	309a	Electrician-Construction and Maintenance	Apprentice 364
365.	309a	Electrician-Construction and Maintenance	Apprentice 365
366.	434a	Powerline Technician	Apprentice 366
367.	434a	Powerline Technician	Apprentice 367
368.	434a	Powerline Technician	Apprentice 368
369.	434a	Powerline Technician	Apprentice 369
370.	434a	Powerline Technician	Apprentice 370
371.	434a	Powerline Technician	Apprentice 371
372.	434a	Powerline Technician	Apprentice 372
373.	434a	Powerline Technician	Apprentice 373
374.	434a	Powerline Technician	Apprentice 374
375.	434a	Powerline Technician	Apprentice 375
376.	434a	Powerline Technician	Apprentice 376
377.	434a	Powerline Technician	Apprentice 377
378.	434a	Powerline Technician	Apprentice 378
379.	434a	Powerline Technician	Apprentice 379
380.	309a	Electrician-Construction and Maintenance	Apprentice 380
381.	434a	Powerline Technician	Apprentice 381
382.	309a	Electrician-Construction and Maintenance	Apprentice 382
383.	309a	Electrician-Construction and Maintenance	Apprentice 383
384.	309a	Electrician-Construction and Maintenance	Apprentice 384
385.	309a	Electrician-Construction and Maintenance	Apprentice 385
386.	309a	Electrician-Construction and Maintenance	Apprentice 386
387.	309a	Electrician-Construction and Maintenance	Apprentice 387
388.	309a	Electrician-Construction and Maintenance	Apprentice 388
389.	309a	Electrician-Construction and Maintenance	Apprentice 389
390.	309a	Electrician-Construction and Maintenance	Apprentice 390
391.	309a	Electrician-Construction and Maintenance	Apprentice 391
392.	309a	Electrician-Construction and Maintenance	Apprentice 392
393.	309a	Electrician-Construction and Maintenance	Apprentice 393
394.	309a	Electrician-Construction and Maintenance	Apprentice 394
395.	309a	Electrician-Construction and Maintenance	Apprentice 395
396.	309a	Electrician-Construction and Maintenance	Apprentice 396
397.	309a	Electrician-Construction and Maintenance	Apprentice 397
398.	309a	Electrician-Construction and Maintenance	Apprentice 398
399.	309a	Electrician-Construction and Maintenance	Apprentice 399
400.	309a	Electrician-Construction and Maintenance	Apprentice 400
401.	309a	Electrician-Construction and Maintenance	Apprentice 401
402.	310t	Truck And Coach Technician	Apprentice 402
403.	310t	Truck And Coach Technician	Apprentice 403
404.	310t	Truck And Coach Technician	Apprentice 404
405.	310t	Truck And Coach Technician	Apprentice 405
406.	434a	Powerline Technician	Apprentice 406
407.	434a	Powerline Technician	Apprentice 407
408.	434a	Powerline Technician	Apprentice 408
409.	434a	Powerline Technician	Apprentice 409
410.	434a	Powerline Technician	Apprentice 410
411.	434a	Powerline Technician	Apprentice 411
412.	434a	Powerline Technician	Apprentice 412

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
413.	434a	Powerline Technician	Apprentice 413
414.	434a	Powerline Technician	Apprentice 414
415.	434a	Powerline Technician	Apprentice 415
416.	434a	Powerline Technician	Apprentice 416
417.	434a	Powerline Technician	Apprentice 417
418.	434a	Powerline Technician	Apprentice 418
419.	434a	Powerline Technician	Apprentice 419
420.	434a	Powerline Technician	Apprentice 420
421.	434a	Powerline Technician	Apprentice 421
422.	434a	Powerline Technician	Apprentice 422
423.	434a	Powerline Technician	Apprentice 423
424.	434a	Powerline Technician	Apprentice 424
425.	434a	Powerline Technician	Apprentice 425
426.	434a	Powerline Technician	Apprentice 426
427.	434a	Powerline Technician	Apprentice 427
428.	434a	Powerline Technician	Apprentice 428
429.	434a	Powerline Technician	Apprentice 429
430.	434a	Powerline Technician	Apprentice 430
431.	434a	Powerline Technician	Apprentice 431
432.	434a	Powerline Technician	Apprentice 432
433.	434a	Powerline Technician	Apprentice 433
434.	434a	Powerline Technician	Apprentice 434
435.	434a	Powerline Technician	Apprentice 435
436.	434a	Powerline Technician	Apprentice 436
437.	434a	Powerline Technician	Apprentice 437
438.	434a	Powerline Technician	Apprentice 438
439.	434a	Powerline Technician	Apprentice 439
440.	434a	Powerline Technician	Apprentice 440
441.	434a	Powerline Technician	Apprentice 441
442.	434a	Powerline Technician	Apprentice 442
443.	434a	Powerline Technician	Apprentice 443
444.	434a	Powerline Technician	Apprentice 444
445.	434a	Powerline Technician	Apprentice 445
446.	434a	Powerline Technician	Apprentice 446
447.	434a	Powerline Technician	Apprentice 447
448.	434a	Powerline Technician	Apprentice 448
449.	434a	Powerline Technician	Apprentice 449
450.	434a	Powerline Technician	Apprentice 450
451.	434a	Powerline Technician	Apprentice 451
452.	434a	Powerline Technician	Apprentice 452
453.	434a	Powerline Technician	Apprentice 453
454.	434a	Powerline Technician	Apprentice 454
455.	434a	Powerline Technician	Apprentice 455
456.	434a	Powerline Technician	Apprentice 456
457.	434a	Powerline Technician	Apprentice 457
458.	434a	Powerline Technician	Apprentice 458
459.	434a	Powerline Technician	Apprentice 459
460.	434a	Powerline Technician	Apprentice 460
461.	434a	Powerline Technician	Apprentice 461
462.	434a	Powerline Technician	Apprentice 462
463.	434a	Powerline Technician	Apprentice 463
464.	434a	Powerline Technician	Apprentice 464
465.	434a	Powerline Technician	Apprentice 465
466.	434a	Powerline Technician	Apprentice 466
467.	434a	Powerline Technician	Apprentice 467

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
468.	309a	Electrician-Construction and Maintenance	Apprentice 468
469.	309a	Electrician-Construction and Maintenance	Apprentice 469
470.	309a	Electrician-Construction and Maintenance	Apprentice 470
471.	309a	Electrician-Construction and Maintenance	Apprentice 471
472.	309a	Electrician-Construction and Maintenance	Apprentice 472
473.	309a	Electrician-Construction and Maintenance	Apprentice 473
474.	309a	Electrician-Construction and Maintenance	Apprentice 474
475.	309a	Electrician-Construction and Maintenance	Apprentice 475
476.	309a	Electrician-Construction and Maintenance	Apprentice 476
477.	309a	Electrician-Construction and Maintenance	Apprentice 477
478.	309a	Electrician-Construction and Maintenance	Apprentice 478
479.	309a	Electrician-Construction and Maintenance	Apprentice 479
480.	433a	Industrial Mechanic (Millwright)	Apprentice 480
481.	433a	Industrial Mechanic (Millwright)	Apprentice 481
482.	434a	Powerline Technician	Apprentice 482
483.	434a	Powerline Technician	Apprentice 483
484.	434a	Powerline Technician	Apprentice 484
485.	434a	Powerline Technician	Apprentice 485
486.	434a	Powerline Technician	Apprentice 486
487.	434a	Powerline Technician	Apprentice 487
488.	434a	Powerline Technician	Apprentice 488
489.	434a	Powerline Technician	Apprentice 489
490.	434a	Powerline Technician	Apprentice 490
491.	434a	Powerline Technician	Apprentice 491
492.	434a	Powerline Technician	Apprentice 492
493.	434a	Powerline Technician	Apprentice 493
494.	434a	Powerline Technician	Apprentice 494
495.	434a	Powerline Technician	Apprentice 495
496.	434a	Powerline Technician	Apprentice 496
497.	434a	Powerline Technician	Apprentice 497
498.	434a	Powerline Technician	Apprentice 498
499.	434a	Powerline Technician	Apprentice 499
500.	434a	Powerline Technician	Apprentice 500
501.	434a	Powerline Technician	Apprentice 501
502.	434a	Powerline Technician	Apprentice 502
503.	434a	Powerline Technician	Apprentice 503
504.	434a	Powerline Technician	Apprentice 504
505.	434a	Powerline Technician	Apprentice 505
506.	434a	Powerline Technician	Apprentice 506
507.	434a	Powerline Technician	Apprentice 507
508.	434a	Powerline Technician	Apprentice 508
509.	434a	Powerline Technician	Apprentice 509
510.	434a	Powerline Technician	Apprentice 510
511.	434a	Powerline Technician	Apprentice 511
512.	434a	Powerline Technician	Apprentice 512
513.	309a	Electrician-Construction and Maintenance	Apprentice 513
514.	309a	Electrician-Construction and Maintenance	Apprentice 514
515.	309a	Electrician-Construction and Maintenance	Apprentice 515
516.	434a	Powerline Technician	Apprentice 516
517.	434a	Powerline Technician	Apprentice 517
518.	434a	Powerline Technician	Apprentice 518
519.	434a	Powerline Technician	Apprentice 519
520.	434a	Powerline Technician	Apprentice 520
521.	434a	Powerline Technician	Apprentice 521
522.	434a	Powerline Technician	Apprentice 522

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
523.	434a	Powerline Technician	Apprentice 523
524.	434a	Powerline Technician	Apprentice 524
525.	434a	Powerline Technician	Apprentice 525
526.	434a	Powerline Technician	Apprentice 526
527.	434a	Powerline Technician	Apprentice 527
528.	434a	Powerline Technician	Apprentice 528
529.	434a	Powerline Technician	Apprentice 529
530.	434a	Powerline Technician	Apprentice 530
531.	434a	Powerline Technician	Apprentice 531
532.	309a	Electrician-Construction and Maintenance	Apprentice 532
533.	309a	Electrician-Construction and Maintenance	Apprentice 533
534.	310t	Truck And Coach Technician	Apprentice 534
535.	310t	Truck And Coach Technician	Apprentice 535
536.	310t	Truck And Coach Technician	Apprentice 536
537.	310t	Truck And Coach Technician	Apprentice 537
538.	309a	Electrician-Construction and Maintenance	Apprentice 538
539.	434a	Powerline Technician	Apprentice 539
540.	434a	Powerline Technician	Apprentice 540
541.	434a	Powerline Technician	Apprentice 541
542.	434a	Powerline Technician	Apprentice 542
543.	434a	Powerline Technician	Apprentice 543
544.	434a	Powerline Technician	Apprentice 544
545.	434a	Powerline Technician	Apprentice 545
546.	434a	Powerline Technician	Apprentice 546
547.	434a	Powerline Technician	Apprentice 547
548.	434a	Powerline Technician	Apprentice 548
549.	434a	Powerline Technician	Apprentice 549
550.	434a	Powerline Technician	Apprentice 550
551.	434a	Powerline Technician	Apprentice 551
552.	434a	Powerline Technician	Apprentice 552
553.	434a	Powerline Technician	Apprentice 553
554.	434a	Powerline Technician	Apprentice 554
555.	434a	Powerline Technician	Apprentice 555
556.	309a	Electrician-Construction and Maintenance	Apprentice 556
557.	309a	Electrician-Construction and Maintenance	Apprentice 557
558.	309a	Electrician-Construction and Maintenance	Apprentice 558
559.	309a	Electrician-Construction and Maintenance	Apprentice 559
560.	309a	Electrician-Construction and Maintenance	Apprentice 560
561.	309a	Electrician-Construction and Maintenance	Apprentice 561
562.	309a	Electrician-Construction and Maintenance	Apprentice 562
563.	309a	Electrician-Construction and Maintenance	Apprentice 563
564.	434a	Powerline Technician	Apprentice 564
565.	434a	Powerline Technician	Apprentice 565
566.	434a	Powerline Technician	Apprentice 566
567.	434a	Powerline Technician	Apprentice 567
568.	434a	Powerline Technician	Apprentice 568
569.	434a	Powerline Technician	Apprentice 569
570.	434a	Powerline Technician	Apprentice 570
571.	434a	Powerline Technician	Apprentice 571
572.	434a	Powerline Technician	Apprentice 572
573.	434a	Powerline Technician	Apprentice 573
574.	434a	Powerline Technician	Apprentice 574
575.	434a	Powerline Technician	Apprentice 575
576.	434a	Powerline Technician	Apprentice 576
577.	434a	Powerline Technician	Apprentice 577

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
578.	434a	Powerline Technician	Apprentice 578
579.	434a	Powerline Technician	Apprentice 579
580.	434a	Powerline Technician	Apprentice 580
581.	434a	Powerline Technician	Apprentice 581
582.	434a	Powerline Technician	Apprentice 582
583.	434a	Powerline Technician	Apprentice 583
584.	434a	Powerline Technician	Apprentice 584
585.	434a	Powerline Technician	Apprentice 585
586.	434a	Powerline Technician	Apprentice 586
587.	434a	Powerline Technician	Apprentice 587
588.	434a	Powerline Technician	Apprentice 588
589.	434a	Powerline Technician	Apprentice 589
590.	434a	Powerline Technician	Apprentice 590
591.	434a	Powerline Technician	Apprentice 591
592.	434a	Powerline Technician	Apprentice 592
593.	434a	Powerline Technician	Apprentice 593
594.	434a	Powerline Technician	Apprentice 594
595.	434a	Powerline Technician	Apprentice 595
596.	434a	Powerline Technician	Apprentice 596
597.	434a	Powerline Technician	Apprentice 597
598.	434a	Powerline Technician	Apprentice 598
599.	434a	Powerline Technician	Apprentice 599
600.	434a	Powerline Technician	Apprentice 600
601.	434a	Powerline Technician	Apprentice 601
602.	434a	Powerline Technician	Apprentice 602
603.	434a	Powerline Technician	Apprentice 603
604.	434a	Powerline Technician	Apprentice 604
605.	434a	Powerline Technician	Apprentice 605
606.	309a	Electrician-Construction and Maintenance	Apprentice 606
607.	309a	Electrician-Construction and Maintenance	Apprentice 607
608.	434a	Powerline Technician	Apprentice 608
609.	434a	Powerline Technician	Apprentice 609
610.	434a	Powerline Technician	Apprentice 610
611.	434a	Powerline Technician	Apprentice 611
612.	434a	Powerline Technician	Apprentice 612
613.	434a	Powerline Technician	Apprentice 613
614.	434a	Powerline Technician	Apprentice 614
615.	434a	Powerline Technician	Apprentice 615
616.	434a	Powerline Technician	Apprentice 616
617.	434a	Powerline Technician	Apprentice 617
618.	434a	Powerline Technician	Apprentice 618
619.	434a	Powerline Technician	Apprentice 619
620.	434a	Powerline Technician	Apprentice 620
621.	434a	Powerline Technician	Apprentice 621
622.	434a	Powerline Technician	Apprentice 622
623.	434a	Powerline Technician	Apprentice 623
624.	309a	Electrician-Construction and Maintenance	Apprentice 624
625.	434a	Powerline Technician	Apprentice 625
626.	434a	Powerline Technician	Apprentice 626
627.	434a	Powerline Technician	Apprentice 627
628.	309a	Electrician-Construction and Maintenance	Apprentice 628
629.	309a	Electrician-Construction and Maintenance	Apprentice 629
630.	309a	Electrician-Construction and Maintenance	Apprentice 630
631.	309a	Electrician-Construction and Maintenance	Apprentice 631
632.	309a	Electrician-Construction and Maintenance	Apprentice 632

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
633.	309a	Electrician-Construction and Maintenance	Apprentice 633
634.	309a	Electrician-Construction and Maintenance	Apprentice 634
635.	309a	Electrician-Construction and Maintenance	Apprentice 635
636.	309a	Electrician-Construction and Maintenance	Apprentice 636
637.	309a	Electrician-Construction and Maintenance	Apprentice 637
638.	309a	Electrician-Construction and Maintenance	Apprentice 638
639.	309a	Electrician-Construction and Maintenance	Apprentice 639
640.	309a	Electrician-Construction and Maintenance	Apprentice 640
641.	309a	Electrician-Construction and Maintenance	Apprentice 641
642.	309a	Electrician-Construction and Maintenance	Apprentice 642
643.	309a	Electrician-Construction and Maintenance	Apprentice 643
644.	309a	Electrician-Construction and Maintenance	Apprentice 644
645.	309a	Electrician-Construction and Maintenance	Apprentice 645
646.	434a	Powerline Technician	Apprentice 646
647.	434a	Powerline Technician	Apprentice 647
648.	434a	Powerline Technician	Apprentice 648
649.	434a	Powerline Technician	Apprentice 649
650.	434a	Powerline Technician	Apprentice 650
651.	434a	Powerline Technician	Apprentice 651
652.	434a	Powerline Technician	Apprentice 652
653.	434a	Powerline Technician	Apprentice 653
654.	434a	Powerline Technician	Apprentice 654
655.	434a	Powerline Technician	Apprentice 655
656.	434a	Powerline Technician	Apprentice 656
657.	434a	Powerline Technician	Apprentice 657
658.	434a	Powerline Technician	Apprentice 658
659.	434a	Powerline Technician	Apprentice 659
660.	434a	Powerline Technician	Apprentice 660
661.	434a	Powerline Technician	Apprentice 661
662.	434a	Powerline Technician	Apprentice 662
663.	434a	Powerline Technician	Apprentice 663
664.	434a	Powerline Technician	Apprentice 664
665.	309a	Electrician-Construction and Maintenance	Apprentice 665
666.	309a	Electrician-Construction and Maintenance	Apprentice 666
667.	434a	Powerline Technician	Apprentice 667
668.	434a	Powerline Technician	Apprentice 668
669.	434a	Powerline Technician	Apprentice 669
670.	434a	Powerline Technician	Apprentice 670
671.	434a	Powerline Technician	Apprentice 671
672.	434a	Powerline Technician	Apprentice 672
673.	434a	Powerline Technician	Apprentice 673
674.	434a	Powerline Technician	Apprentice 674
675.	434a	Powerline Technician	Apprentice 675
676.	434a	Powerline Technician	Apprentice 676
677.	434a	Powerline Technician	Apprentice 677
678.	434a	Powerline Technician	Apprentice 678
679.	434a	Powerline Technician	Apprentice 679
680.	434a	Powerline Technician	Apprentice 680
681.	434a	Powerline Technician	Apprentice 681
682.	434a	Powerline Technician	Apprentice 682
683.	434a	Powerline Technician	Apprentice 683
684.	434a	Powerline Technician	Apprentice 684
685.	434a	Powerline Technician	Apprentice 685
686.	434a	Powerline Technician	Apprentice 686
687.	434a	Powerline Technician	Apprentice 687

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
688.	434a	Powerline Technician	Apprentice 688
689.	434a	Powerline Technician	Apprentice 689
690.	434a	Powerline Technician	Apprentice 690
691.	434a	Powerline Technician	Apprentice 691

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	PF6430	2012-01-26	2016-01-01	2016-01-25
2.	PG4580	2012-01-30	2016-01-01	2016-01-29
3.	PG4585	2012-01-30	2016-01-01	2016-01-29
4.	PG4583	2012-01-30	2016-01-01	2016-01-29
5.	PG4575	2012-01-30	2016-01-01	2016-01-29
6.	PG4584	2012-01-30	2016-01-01	2016-01-29
7.	PD5713	2012-01-30	2016-01-01	2016-01-29
8.	PE6763	2012-01-30	2016-01-01	2016-01-29
9.	PG4577	2012-01-30	2016-01-01	2016-01-29
10.	PG4579	2012-01-30	2016-01-01	2016-01-29
11.	PG4582	2012-01-30	2016-01-01	2016-01-29
12.	PG4581	2012-01-30	2016-01-01	2016-01-29
13.	PG4576	2012-01-30	2016-01-01	2016-01-29
14.	PG4578	2012-01-30	2016-01-01	2016-01-29
15.	PE6764	2012-01-30	2016-01-01	2016-01-29
16.	PG4567	2012-01-30	2016-01-01	2016-01-29
17.	101449A	2012-02-06	2016-01-01	2016-02-05
18.	PE6767	2012-02-06	2016-01-01	2016-02-05
19.	PE6782	2012-02-27	2016-01-01	2016-02-26
20.	PE6783	2012-02-27	2016-01-01	2016-02-26
21.	PE6779	2012-02-27	2016-01-01	2016-02-26
22.	PE6768	2012-02-27	2016-01-01	2016-02-26
23.	PE6775	2012-02-27	2016-01-01	2016-02-26
24.	PE6776	2012-02-27	2016-01-01	2016-02-26
25.	PE6778	2012-02-27	2016-01-01	2016-02-26
26.	PE6784	2012-02-27	2016-01-01	2016-02-26
27.	PB6677	2012-02-27	2016-01-01	2016-02-26
28.	PE6766	2012-02-27	2016-01-01	2016-02-26
29.	PE4038	2012-02-27	2016-01-01	2016-01-20
30.	PE6777	2012-02-27	2016-01-01	2016-02-26
31.	PE6765	2012-02-27	2016-01-01	2016-02-26
32.	PE6774	2012-02-27	2016-01-01	2016-02-26
33.	PE6781	2012-02-27	2016-01-01	2016-02-26
34.	PE6780	2012-02-27	2016-01-01	2016-02-26
35.	PE6773	2012-02-27	2016-01-01	2016-02-26
36.	PD3377	2012-03-04	2016-01-01	2016-03-03
37.	PD3383	2012-03-29	2016-01-01	2016-03-28
38.	PD3382	2012-03-29	2016-01-01	2016-01-15
39.	PD3384	2012-03-29	2016-01-01	2016-03-28
40.	PD3379	2012-03-29	2016-01-01	2016-03-28
41.	PD3378	2012-03-29	2016-01-01	2016-03-22
42.	PF9102	2012-04-19	2016-01-01	2016-04-18
43.	CD1493	2012-05-04	2016-01-01	2016-05-03
44.	PF9114	2012-05-08	2016-01-01	2016-05-07

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45.	PF9116	2012-05-08	2016-01-01	2016-05-07
46.	PF9115	2012-05-08	2016-01-01	2016-05-05
47.	PF9112	2012-05-08	2016-01-01	2016-05-07
48.	PF9120	2012-05-08	2016-01-01	2016-05-07
49.	PF9119	2012-05-08	2016-01-01	2016-05-07
50.	PF9121	2012-05-08	2016-01-01	2016-04-04
51.	PF9126	2012-05-08	2016-01-01	2016-05-07
52.	AQ1140	2012-05-28	2016-01-01	2016-01-04
53.	AQ1140	2012-05-28	2016-03-25	2016-05-27
54.	AQ1139	2012-05-28	2016-01-01	2016-01-26
55.	PE6792	2012-05-28	2016-01-01	2016-05-27
56.	PG4983	2012-05-28	2016-01-01	2016-03-07
57.	PE6794	2012-05-28	2016-01-01	2016-05-27
58.	PE6790	2012-05-28	2016-01-01	2016-05-27
59.	PE6793	2012-05-28	2016-01-01	2016-05-27
60.	PE6797	2012-05-28	2016-01-01	2016-05-27
61.	PE6786	2012-05-28	2016-01-01	2016-05-27
62.	PC7890	2012-05-28	2016-01-01	2016-05-27
63.	PE6787	2012-05-28	2016-01-01	2016-05-27
64.	PE6788	2012-05-28	2016-01-01	2016-05-27
65.	PE6789	2012-05-28	2016-01-01	2016-05-27
66.	PE6796	2012-05-28	2016-01-01	2016-05-27
67.	PE6795	2012-05-28	2016-01-01	2016-05-27
68.	PD3389	2012-07-26	2016-01-01	2016-07-25
69.	PE6952	2012-08-23	2016-01-01	2016-08-22
70.	PD3387	2012-08-23	2016-01-01	2016-08-22
71.	PD3386	2012-08-23	2016-01-01	2016-08-22
72.	PD3388	2012-08-23	2016-01-01	2016-08-22
73.	PF9109	2012-09-06	2016-01-01	2016-03-30
74.	PF9108	2012-09-06	2016-06-13	2016-09-05
75.	PD3394	2012-10-15	2016-01-01	2016-10-14
76.	PE6951	2012-10-15	2016-01-01	2016-10-14
77.	PD3393	2012-10-15	2016-01-01	2016-10-14
78.	PD3391	2012-10-15	2016-01-01	2016-10-14
79.	PD3392	2012-10-15	2016-01-01	2016-10-14
80.	BA9987	2012-10-15	2016-01-01	2016-10-14
81.	PF9137	2012-11-08	2016-01-01	2016-11-07
82.	PF9135	2012-11-08	2016-01-01	2016-08-16
83.	PF9140	2012-11-08	2016-01-01	2016-06-15
84.	PF9134	2012-11-08	2016-01-01	2016-08-22
85.	PA1242	2012-11-08	2016-01-01	2016-09-13
86.	PF9136	2012-11-08	2016-01-01	2016-04-12
87.	PF9138	2012-11-08	2016-01-01	2016-10-17
88.	PF9133	2012-11-08	2016-01-01	2016-11-08
89.	PF9132	2012-11-08	2016-01-01	2016-09-12
90.	PE6955	2012-11-12	2016-01-01	2016-11-12
91.	PE6958	2012-12-10	2016-01-01	2016-12-10
92.	AJ8937	2013-01-28	2016-01-01	2016-07-29
93.	AY4001	2013-01-28	2016-01-01	2016-06-03
94.	AY4002	2013-01-28	2016-01-01	2016-03-30
95.	PE3482	2013-01-28	2016-01-01	2016-12-31
96.	PE3809	2013-01-28	2016-01-01	2016-01-04
97.	PE3809	2013-01-28	2016-06-30	2016-12-31

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98.	PE3813	2013-01-28	2016-01-01	2016-12-31
99.	PG4232	2013-01-28	2016-01-01	2016-10-28
100.	PE3803	2013-01-28	2016-01-01	2016-12-31
101.	PE3812	2013-01-28	2016-01-01	2016-12-31
102.	PE3806	2013-01-28	2016-01-01	2016-12-31
103.	PE0337	2013-01-28	2016-01-01	2016-12-31
104.	PE3481	2013-01-28	2016-01-01	2016-12-31
105.	PE3807	2013-01-28	2016-01-01	2016-12-31
106.	PE3810	2013-01-28	2016-01-01	2016-12-31
107.	PE3811	2013-01-28	2016-01-01	2016-07-04
108.	PE3811	2013-01-28	2016-12-23	2016-12-31
109.	PE3805	2013-01-28	2016-01-01	2016-12-31
110.	PE3802	2013-01-28	2016-01-01	2016-12-31
111.	PE3808	2013-01-28	2016-01-01	2016-12-31
112.	PE3493	2013-02-25	2016-01-01	2016-12-31
113.	PE3489	2013-02-25	2016-01-01	2016-12-31
114.	PE3491	2013-02-25	2016-01-01	2016-12-31
115.	PE3484	2013-02-25	2016-01-01	2016-12-31
116.	PE3486	2013-02-25	2016-01-01	2016-12-31
117.	PE3495	2013-02-25	2016-01-01	2016-08-24
118.	PE3498	2013-02-25	2016-01-01	2016-12-31
119.	PE3494	2013-02-25	2016-01-01	2016-12-31
120.	PE3485	2013-02-25	2016-01-01	2016-12-31
121.	PE3487	2013-02-25	2016-01-01	2016-12-31
122.	PE3488	2013-02-25	2016-01-01	2016-12-31
123.	PE3490	2013-02-25	2016-01-01	2016-12-31
124.	PE3492	2013-02-25	2016-01-01	2016-12-31
125.	PE3497	2013-02-25	2016-01-01	2016-12-31
126.	PE3483	2013-02-25	2016-01-01	2016-12-31
127.	PE6959	2013-03-13	2016-01-01	2016-12-31
128.	101325A	2013-03-18	2016-01-01	2016-10-06
129.	BA3464	2013-04-15	2016-01-01	2016-12-31
130.	BA3466	2013-04-15	2016-01-01	2016-12-31
131.	BA3468	2013-04-15	2016-01-01	2016-12-31
132.	BA3469	2013-04-15	2016-01-01	2016-12-31
133.	BA3463	2013-04-15	2016-01-01	2016-12-31
134.	BA3456	2013-04-15	2016-01-01	2016-12-31
135.	BA3471	2013-04-15	2016-01-01	2016-12-31
136.	BA3461	2013-04-15	2016-01-01	2016-12-31
137.	BA3465	2013-04-15	2016-01-01	2016-12-31
138.	BA3470	2013-04-15	2016-01-01	2016-12-31
139.	BA3455	2013-04-15	2016-01-01	2016-12-31
140.	BA3457	2013-04-15	2016-01-01	2016-12-31
141.	BA3460	2013-04-15	2016-01-01	2016-12-31
142.	BA3459	2013-04-15	2016-01-01	2016-12-31
143.	BA3467	2013-04-15	2016-01-01	2016-08-11
144.	BA3462	2013-04-15	2016-01-01	2016-12-31
145.	BA3499	2013-04-29	2016-01-01	2016-12-31
146.	BA3488	2013-04-29	2016-01-01	2016-12-31
147.	BA3493	2013-04-29	2016-01-01	2016-12-31
148.	BA3486	2013-04-29	2016-01-01	2016-12-31
149.	BA3498	2013-04-29	2016-01-01	2016-12-31
150.	BA3494	2013-04-29	2016-01-01	2016-12-31

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151.	BA3487	2013-04-29	2016-01-01	2016-12-31
152.	BA3489	2013-04-29	2016-01-01	2016-12-31
153.	BA3497	2013-04-29	2016-01-01	2016-12-31
154.	BA3491	2013-04-29	2016-01-01	2016-12-31
155.	BA3485	2013-04-29	2016-01-01	2016-12-31
156.	BA3496	2013-04-29	2016-01-01	2016-12-31
157.	BA3492	2013-04-29	2016-01-01	2016-12-31
158.	BA3490	2013-04-29	2016-01-01	2016-12-31
159.	BA3484	2013-04-29	2016-01-01	2016-12-31
160.	BA3495	2013-04-29	2016-01-01	2016-12-31
161.	BA3500	2013-06-03	2016-01-01	2016-12-31
162.	BA3501	2013-06-03	2016-01-01	2016-06-17
163.	BA3503	2013-06-03	2016-01-01	2016-11-07
164.	BA3504	2013-06-03	2016-01-01	2016-12-31
165.	BA3505	2013-06-03	2016-01-01	2016-12-31
166.	BA3506	2013-06-03	2016-01-01	2016-12-31
167.	BA3507	2013-06-03	2016-01-01	2016-12-31
168.	BA3508	2013-06-03	2016-01-01	2016-12-31
169.	BA3511	2013-06-03	2016-01-01	2016-12-31
170.	BA3512	2013-06-03	2016-01-01	2016-12-31
171.	BA3513	2013-06-03	2016-01-01	2016-12-31
172.	BA3515	2013-06-03	2016-01-01	2016-12-31
173.	BA3516	2013-06-03	2016-01-01	2016-12-31
174.	BA3517	2013-06-03	2016-01-01	2016-12-31
175.	BA3519	2013-06-03	2016-01-01	2016-12-31
176.	BA3520	2013-06-03	2016-01-01	2016-12-31
177.	BA3522	2013-06-03	2016-01-01	2016-12-31
178.	BB5918	2013-06-03	2016-01-01	2016-12-31
179.	BA3510	2013-06-03	2016-01-01	2016-12-31
180.	CB8074	2013-06-03	2016-01-01	2016-12-31
181.	BA3521	2013-06-03	2016-01-01	2016-01-18
182.	BA3502	2013-06-03	2016-01-01	2016-12-31
183.	BA7420	2013-06-20	2016-01-01	2016-12-31
184.	BA7421	2013-06-20	2016-01-01	2016-12-31
185.	BA7423	2013-06-20	2016-01-01	2016-12-31
186.	BA7133	2013-06-20	2016-01-01	2016-12-31
187.	BA7425	2013-06-20	2016-01-01	2016-12-31
188.	BA7422	2013-06-20	2016-01-01	2016-12-31
189.	BA7134	2013-06-20	2016-01-01	2016-12-31
190.	BC2665	2013-06-20	2016-01-01	2016-12-31
191.	BA7428	2013-06-20	2016-01-01	2016-12-31
192.	BA7108	2013-06-29	2016-01-01	2016-12-31
193.	BA7132	2013-06-29	2016-01-01	2016-12-31
194.	BA7431	2013-07-23	2016-01-01	2016-12-31
195.	BA7434	2013-07-23	2016-01-01	2016-12-31
196.	BA7433	2013-07-23	2016-01-01	2016-12-31
197.	CH07533	2013-09-17	2016-02-29	2016-12-31
198.	BE0777	2013-10-11	2016-01-01	2016-12-31
199.	BE0770	2013-10-16	2016-01-01	2016-12-31
200.	BE0769	2013-10-16	2016-01-01	2016-12-31
201.	BE0763	2013-10-16	2016-01-01	2016-10-25
202.	BA7450	2013-10-16	2016-01-01	2016-10-03
203.	BA7452	2013-10-16	2016-01-01	2016-12-31

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204.	BA7451	2013-10-16	2016-01-01	2016-12-31
205.	BE0771	2013-10-16	2016-01-01	2016-12-31
206.	BE0776	2013-10-16	2016-01-01	2016-12-31
207.	BE0761	2013-10-17	2016-01-01	2016-12-31
208.	BA7453	2013-10-17	2016-01-01	2016-12-31
209.	BA7454	2013-10-17	2016-01-01	2016-01-13
210.	BE0762	2013-10-17	2016-01-01	2016-12-31
211.	BE0772	2013-10-18	2016-01-01	2016-12-31
212.	BC2636	2013-10-21	2016-01-01	2016-12-31
213.	BA7443	2013-10-21	2016-01-01	2016-12-31
214.	BA7444	2013-10-21	2016-01-01	2016-12-31
215.	2641	2013-10-21	2016-01-01	2016-12-31
216.	BC2654	2013-10-21	2016-01-01	2016-09-12
217.	BC2640	2013-10-21	2016-01-01	2016-12-31
218.	BC2648	2013-10-21	2016-01-01	2016-12-31
219.	BC2647	2013-10-21	2016-01-01	2016-06-03
220.	BC2643	2013-10-21	2016-01-01	2016-12-31
221.	BE0780	2013-10-21	2016-01-01	2016-12-31
222.	BC2646	2013-10-21	2016-01-01	2016-12-31
223.	BE0779	2013-10-21	2016-01-01	2016-12-31
224.	BC2637	2013-10-21	2016-01-01	2016-12-31
225.	BE0767	2013-10-21	2016-01-01	2016-12-31
226.	BA7446	2013-10-21	2016-01-01	2016-02-09
227.	BE0764	2013-10-21	2016-01-01	2016-12-31
228.	BA0765	2013-10-21	2016-01-01	2016-12-31
229.	BC2662	2013-10-31	2016-01-01	2016-04-06
230.	BE0766	2013-10-31	2016-01-01	2016-12-31
231.	BE0778	2013-11-07	2016-01-01	2016-12-31
232.	BE0775	2013-11-11	2016-01-01	2016-12-31
233.	BA2657	2013-11-19	2016-01-01	2016-12-31
234.	BA2656	2013-11-19	2016-01-01	2016-12-31
235.	BA2658	2013-11-19	2016-01-01	2016-12-31
236.	BA2655	2013-11-19	2016-01-01	2016-12-31
237.	BC2659	2013-11-19	2016-01-01	2016-12-31
238.	BC2669	2013-11-21	2016-01-01	2016-12-31
239.	BA3550	2014-01-13	2016-01-01	2016-05-24
240.	BA3548	2014-01-13	2016-01-01	2016-07-04
241.	BA3551	2014-01-13	2016-01-01	2016-10-03
242.	BA3549	2014-01-13	2016-01-01	2016-06-09
243.	BA3552	2014-01-13	2016-01-01	2016-04-24
244.	BA3552	2014-01-13	2016-07-29	2016-12-31
245.	BA3553	2014-01-13	2016-01-01	2016-12-31
246.	BC1690	2014-01-15	2016-01-01	2016-12-31
247.	CA2225	2014-01-27	2016-01-01	2016-12-31
248.	BC9541	2014-01-27	2016-01-01	2016-12-31
249.	BC9530	2014-01-27	2016-01-01	2016-12-31
250.	BC9535	2014-01-27	2016-01-01	2016-12-31
251.	BC9532	2014-01-27	2016-01-01	2016-12-31
252.	BC9543	2014-01-27	2016-01-01	2016-12-31
253.	PC9533	2014-01-27	2016-01-01	2016-12-31
254.	BC9540	2014-01-27	2016-01-01	2016-12-31
255.	BC9545	2014-01-27	2016-01-01	2016-12-31
256.	BC9537	2014-01-27	2016-01-01	2016-12-31

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257.	BC9538	2014-01-27	2016-01-01	2016-12-31
258.	BC9536	2014-01-27	2016-01-01	2016-12-31
259.	BC9531	2014-01-27	2016-01-01	2016-12-31
260.	BC9534	2014-01-27	2016-01-01	2016-12-31
261.	BC9542	2014-01-27	2016-01-01	2016-12-31
262.	BC2574	2014-02-05	2016-01-01	2016-12-31
263.	BC2588	2014-02-05	2016-01-01	2016-12-31
264.	BC9553	2014-02-24	2016-01-01	2016-12-31
265.	BC9548	2014-02-24	2016-01-01	2016-12-31
266.	BC9547	2014-02-24	2016-01-01	2016-12-31
267.	BC9561	2014-02-24	2016-01-01	2016-12-31
268.	BC9558	2014-02-24	2016-01-01	2016-12-31
269.	BC9559	2014-02-24	2016-01-01	2016-12-31
270.	BC9549	2014-02-24	2016-01-01	2016-12-31
271.	BC9550	2014-02-24	2016-01-01	2016-12-31
272.	BC9557	2014-02-24	2016-01-01	2016-12-31
273.	BC9552	2014-02-24	2016-01-01	2016-12-31
274.	BC9551	2014-02-24	2016-01-01	2016-12-31
275.	BC9560	2014-02-24	2016-01-01	2016-12-31
276.	BC9555	2014-02-24	2016-01-01	2016-12-31
277.	BC9546	2014-02-24	2016-01-01	2016-10-01
278.	BC9556	2014-02-24	2016-01-01	2016-12-31
279.	BC9554	2014-02-24	2016-01-01	2016-12-31
280.	BA3546	2014-02-24	2016-01-01	2016-12-31
281.	BC2545	2014-03-11	2016-01-01	2016-12-31
282.	BC2546	2014-03-11	2016-01-01	2016-12-31
283.	BC2533	2014-03-11	2016-01-01	2016-12-31
284.	BC9574	2014-03-17	2016-01-01	2016-12-31
285.	BC9576	2014-03-17	2016-01-01	2016-12-31
286.	CB8030	2014-03-17	2016-01-01	2016-12-31
287.	CB8031	2014-03-17	2016-01-01	2016-12-31
288.	CB8032	2014-03-17	2016-01-01	2016-12-31
289.	CB8033	2014-03-17	2016-01-01	2016-12-31
290.	CB8034	2014-03-17	2016-01-01	2016-12-31
291.	CB8035	2014-03-17	2016-01-01	2016-12-31
292.	CB8036	2014-03-17	2016-01-01	2016-12-31
293.	CB8037	2014-03-17	2016-01-01	2016-12-31
294.	CB8038	2014-03-17	2016-01-01	2016-12-31
295.	CB8039	2014-03-17	2016-01-01	2016-12-31
296.	CB8040	2014-03-17	2016-01-01	2016-12-31
297.	CB8041	2014-03-17	2016-01-01	2016-12-31
298.	CB8042	2014-03-17	2016-01-01	2016-12-31
299.	BC2548	2014-03-18	2016-01-01	2016-09-14
300.	BC2549	2014-03-18	2016-01-01	2016-12-31
301.	BC2547	2014-03-18	2016-01-01	2016-12-31
302.	BC2576	2014-04-04	2016-01-01	2016-12-31
303.	BC2554	2014-04-04	2016-09-22	2016-12-31
304.	BC2558	2014-04-04	2016-01-01	2016-12-31
305.	BC2540	2014-04-04	2016-01-01	2016-12-31
306.	BC2553	2014-04-04	2016-01-01	2016-12-31
307.	BC2561	2014-04-04	2016-01-01	2016-12-31
308.	BC2562	2014-04-04	2016-01-01	2016-12-31
309.	BC2563	2014-04-04	2016-01-01	2016-12-31

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310.	BC2567	2014-04-04	2016-01-01	2016-12-31
311.	BC2551	2014-04-04	2016-01-01	2016-12-31
312.	BC2565	2014-04-04	2016-01-01	2016-12-31
313.	BC2566	2014-04-04	2016-01-01	2016-12-31
314.	BC2556	2014-04-04	2016-01-01	2016-12-31
315.	BC2573	2014-04-09	2016-01-01	2016-12-31
316.	BC2575	2014-04-09	2016-01-01	2016-12-31
317.	BC2560	2014-04-09	2016-01-01	2016-12-31
318.	BC2564	2014-04-09	2016-01-01	2016-12-31
319.	BC2568	2014-04-23	2016-01-01	2016-12-31
320.	CB8069	2014-04-28	2016-01-01	2016-07-13
321.	CB8068	2014-04-28	2016-01-01	2016-12-31
322.	CB8062	2014-04-28	2016-01-01	2016-12-31
323.	CB8067	2014-04-28	2016-01-01	2016-12-31
324.	CB8064	2014-04-28	2016-01-01	2016-12-31
325.	CB8065	2014-04-28	2016-01-01	2016-12-31
326.	CB8070	2014-04-28	2016-01-01	2016-12-31
327.	CB8072	2014-04-28	2016-01-01	2016-12-31
328.	CB8060	2014-04-28	2016-01-01	2016-12-31
329.	CB8073	2014-04-28	2016-01-01	2016-12-31
330.	CB8059	2014-04-28	2016-01-01	2016-12-31
331.	CE01201	2014-04-28	2016-01-01	2016-12-31
332.	CB8057	2014-04-28	2016-01-01	2016-12-31
333.	CB8058	2014-04-28	2016-01-01	2016-12-31
334.	CB8061	2014-04-28	2016-01-01	2016-12-31
335.	CD4078	2014-04-28	2016-01-01	2016-12-31
336.	CB8063	2014-04-28	2016-01-01	2016-12-31
337.	BC2582	2014-05-02	2016-01-01	2016-12-31
338.	BC2584	2014-05-02	2016-01-01	2016-12-31
339.	BC2592	2014-05-02	2016-01-01	2016-10-27
340.	BC2590	2014-05-02	2016-01-01	2016-12-31
341.	BC2589	2014-05-02	2016-01-01	2016-12-31
342.	BC2587	2014-05-02	2016-01-01	2016-12-31
343.	BC2581	2014-05-02	2016-01-01	2016-12-31
344.	BC2579	2014-05-02	2016-01-01	2016-12-31
345.	BC2591	2014-05-02	2016-01-01	2016-12-31
346.	BC2585	2014-05-02	2016-01-01	2016-12-31
347.	CB8103	2014-05-26	2016-01-01	2016-12-31
348.	CB8104	2014-05-26	2016-01-01	2016-12-31
349.	CB8106	2014-05-26	2016-01-01	2016-12-31
350.	CB8107	2014-05-26	2016-01-01	2016-12-31
351.	CB8108	2014-05-26	2016-01-01	2016-12-31
352.	CB8109	2014-05-26	2016-01-01	2016-12-31
353.	CB8110	2014-05-26	2016-01-01	2016-12-31
354.	CB8111	2014-05-26	2016-01-01	2016-12-31
355.	CB8112	2014-05-26	2016-01-01	2016-12-31
356.	CB8113	2014-05-26	2016-01-01	2016-12-31
357.	CB8114	2014-05-26	2016-12-16	2016-12-31
358.	CB8115	2014-05-26	2016-01-01	2016-12-31
359.	CB8116	2014-05-26	2016-01-01	2016-12-31
360.	CB8117	2014-05-26	2016-01-01	2016-12-31
361.	CB8118	2014-05-26	2016-01-01	2016-12-31
362.	CB8119	2014-05-26	2016-01-01	2016-12-31

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363.	CB8120	2014-05-26	2016-01-01	2016-12-31
364.	CB8121	2014-05-26	2016-01-01	2016-12-31
365.	CB8122	2014-05-26	2016-01-01	2016-12-31
366.	CB8096	2014-05-26	2016-01-01	2016-12-31
367.	CB8092	2014-05-26	2016-01-01	2016-12-31
368.	CB8088	2014-05-26	2016-01-01	2016-12-31
369.	CB8101	2014-05-26	2016-01-01	2016-12-31
370.	CB8089	2014-05-26	2016-01-01	2016-12-31
371.	CB8097	2014-05-26	2016-01-01	2016-12-31
372.	CB8091	2014-05-26	2016-01-01	2016-12-31
373.	CB8095	2014-05-26	2016-01-01	2016-12-31
374.	CB8087	2014-05-26	2016-01-01	2016-12-31
375.	CB8098	2014-05-26	2016-01-01	2016-12-31
376.	CB8099	2014-05-26	2016-01-01	2016-12-31
377.	CB8102	2014-05-26	2016-01-01	2016-12-31
378.	CB8100	2014-05-26	2016-01-01	2016-12-31
379.	CB8094	2014-05-26	2016-01-01	2016-12-31
380.	CD6228	2014-06-08	2016-01-01	2016-12-31
381.	CD6264	2014-06-10	2016-01-01	2016-12-31
382.	CD6205	2014-06-11	2016-01-01	2016-12-31
383.	CD6206	2014-06-11	2016-01-01	2016-12-31
384.	CD6207	2014-06-11	2016-01-01	2016-12-31
385.	CD6221	2014-06-25	2016-01-01	2016-12-31
386.	CD6208	2014-06-25	2016-01-01	2016-12-31
387.	CD6209	2014-06-25	2016-01-01	2016-02-19
388.	CD6210	2014-06-25	2016-01-01	2016-12-31
389.	CD6274	2014-11-07	2016-01-01	2016-08-03
390.	CD6281	2014-12-15	2016-01-01	2016-12-31
391.	CD6279	2014-12-15	2016-01-01	2016-12-31
392.	CD6286	2014-12-15	2016-01-01	2016-12-31
393.	CD6285	2014-12-15	2016-01-01	2016-12-31
394.	CD6294	2014-12-15	2016-01-01	2016-12-31
395.	CD6280	2014-12-15	2016-01-01	2016-12-31
396.	CD6288	2014-12-15	2016-01-01	2016-12-31
397.	CD6283	2014-12-15	2016-01-01	2016-12-31
398.	CD6284	2014-12-15	2016-01-01	2016-12-21
399.	CD6282	2014-12-15	2016-01-01	2016-12-31
400.	CD6265	2014-12-15	2016-01-01	2016-12-31
401.	CD6295	2014-12-15	2016-01-01	2016-12-31
402.	CD4083	2015-01-26	2016-01-01	2016-12-31
403.	CD4079	2015-01-26	2016-01-01	2016-12-31
404.	CD4082	2015-01-26	2016-01-01	2016-12-31
405.	CD4081	2015-01-26	2016-01-01	2016-12-31
406.	CD6326	2015-02-20	2016-01-01	2016-12-31
407.	CD6323	2015-02-20	2016-01-01	2016-12-31
408.	CD6334	2015-03-03	2016-01-01	2016-12-31
409.	CE01212	2015-03-19	2016-01-01	2016-12-31
410.	CE01217	2015-03-19	2016-01-01	2016-12-31
411.	CE01207	2015-03-19	2016-01-01	2016-12-31
412.	CE01215	2015-03-19	2016-01-01	2016-12-31
413.	CE01210	2015-03-19	2016-01-01	2016-12-31
414.	CE01204	2015-03-19	2016-01-01	2016-12-31
415.	CE01213	2015-03-19	2016-01-01	2016-12-31

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416.	CE01214	2015-03-19	2016-01-01	2016-12-31
417.	CE01208	2015-03-19	2016-01-01	2016-12-31
418.	CE01205	2015-03-19	2016-01-01	2016-12-31
419.	CE01211	2015-03-19	2016-01-01	2016-12-31
420.	CE01203	2015-03-19	2016-01-01	2016-12-31
421.	CE01202	2015-03-19	2016-01-01	2016-12-31
422.	CE01206	2015-03-19	2016-01-01	2016-12-31
423.	CE01216	2015-03-19	2016-01-01	2016-12-31
424.	CE01209	2015-03-19	2016-01-01	2016-12-31
425.	CD6333	2015-03-23	2016-01-01	2016-03-07
426.	CD6345	2015-03-23	2016-01-01	2016-12-31
427.	CD6336	2015-03-23	2016-01-01	2016-12-31
428.	CD6332	2015-03-23	2016-01-01	2016-12-31
429.	CD6337	2015-03-23	2016-01-01	2016-12-31
430.	CD6330	2015-03-23	2016-01-01	2016-12-31
431.	CD6331	2015-03-23	2016-01-01	2016-12-31
432.	CD6341	2015-03-23	2016-01-01	2016-12-31
433.	CD6342	2015-03-23	2016-01-01	2016-12-31
434.	CD6343	2015-04-02	2016-01-01	2016-12-31
435.	CE01220	2015-04-16	2016-01-01	2016-12-31
436.	CE01221	2015-04-16	2016-01-01	2016-12-31
437.	CE01219	2015-04-16	2016-01-01	2016-12-31
438.	CE01232	2015-04-16	2016-01-01	2016-12-31
439.	CE01234	2015-04-16	2016-01-01	2016-12-31
440.	CE01222	2015-04-16	2016-01-01	2016-12-31
441.	CE01223	2015-04-16	2016-01-01	2016-12-31
442.	CE01225	2015-04-16	2016-01-01	2016-12-31
443.	CE01229	2015-04-16	2016-01-01	2016-12-31
444.	CE01231	2015-04-16	2016-01-01	2016-12-31
445.	CE01228	2015-04-16	2016-01-01	2016-12-31
446.	CE01226	2015-04-16	2016-01-01	2016-12-31
447.	CE01233	2015-04-16	2016-01-01	2016-12-31
448.	CE01230	2015-04-16	2016-01-01	2016-04-01
449.	CE01227	2015-04-16	2016-01-01	2016-12-31
450.	CE01241	2015-04-16	2016-01-01	2016-12-31
451.	CE01237	2015-04-16	2016-01-01	2016-12-31
452.	CE01248	2015-04-16	2016-01-01	2016-10-19
453.	CE01246	2015-04-16	2016-01-01	2016-12-31
454.	CE01249	2015-04-16	2016-01-01	2016-12-31
455.	CE01244	2015-04-16	2016-01-01	2016-12-31
456.	CE01243	2015-04-16	2016-01-01	2016-12-31
457.	CE01242	2015-04-16	2016-01-01	2016-12-31
458.	CE01238	2015-04-16	2016-01-01	2016-12-31
459.	CE01240	2015-04-16	2016-01-01	2016-12-31
460.	CE01245	2015-04-16	2016-01-01	2016-12-31
461.	CE01251	2015-04-16	2016-01-01	2016-12-31
462.	CE01236	2015-04-16	2016-01-01	2016-12-31
463.	CE01247	2015-04-16	2016-01-01	2016-12-31
464.	CE01250	2015-04-16	2016-01-01	2016-12-31
465.	CE01239	2015-04-16	2016-01-01	2016-09-01
466.	CD6338	2015-05-02	2016-01-01	2016-12-31
467.	CD6340	2015-05-16	2016-01-01	2016-12-31
468.	CD6347	2015-05-26	2016-01-01	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
469.	CD6348	2015-05-26	2016-01-01	2016-12-31
470.	CE01310	2015-07-13	2016-01-01	2016-12-31
471.	CE01311	2015-07-13	2016-01-01	2016-12-31
472.	CE01312	2015-07-13	2016-01-01	2016-12-31
473.	CE01313	2015-07-13	2016-01-01	2016-12-31
474.	CE01314	2015-07-13	2016-01-01	2016-12-31
475.	CE01315	2015-07-13	2016-01-01	2016-12-31
476.	CE01316	2015-07-13	2016-01-01	2016-12-31
477.	CE01317	2015-07-13	2016-01-01	2016-12-31
478.	CE01318	2015-07-13	2016-01-01	2016-12-31
479.	CE01319	2015-07-13	2016-01-01	2016-12-31
480.	CE01320	2015-07-13	2016-01-01	2016-12-31
481.	CE01321	2015-07-13	2016-01-01	2016-12-31
482.	CE01282	2015-07-13	2016-01-01	2016-12-31
483.	CE01290	2015-07-13	2016-01-01	2016-12-31
484.	CE01293	2015-07-13	2016-01-01	2016-12-31
485.	CE01279	2015-07-13	2016-01-01	2016-12-31
486.	CE01283	2015-07-13	2016-01-01	2016-12-31
487.	CE01278	2015-07-13	2016-01-01	2016-12-31
488.	CE01285	2015-07-13	2016-01-01	2016-08-12
489.	CE01281	2015-07-13	2016-01-01	2016-12-31
490.	CE01286	2015-07-13	2016-01-01	2016-12-31
491.	CE01287	2015-07-13	2016-01-01	2016-12-31
492.	CE01280	2015-07-13	2016-01-01	2016-12-31
493.	CE01288	2015-07-13	2016-01-01	2016-12-31
494.	CE01291	2015-07-13	2016-01-01	2016-12-31
495.	CE01284	2015-07-13	2016-01-01	2016-12-31
496.	CE01289	2015-07-13	2016-01-01	2016-12-31
497.	CE01292	2015-07-13	2016-01-01	2016-12-31
498.	CE01294	2015-07-13	2016-01-01	2016-12-31
499.	CE01306	2015-07-13	2016-01-01	2016-12-31
500.	CE01295	2015-07-13	2016-01-01	2016-12-31
501.	CE01302	2015-07-13	2016-01-01	2016-12-31
502.	CE01296	2015-07-13	2016-01-01	2016-12-31
503.	CE01301	2015-07-13	2016-01-01	2016-12-31
504.	CE01308	2015-07-13	2016-01-01	2016-12-31
505.	CE01297	2015-07-13	2016-01-01	2016-12-31
506.	CE01303	2015-07-13	2016-01-01	2016-12-31
507.	CE01309	2015-07-13	2016-01-01	2016-12-31
508.	CE01307	2015-07-13	2016-01-01	2016-12-31
509.	CE01224	2015-07-13	2016-01-01	2016-12-31
510.	CE01305	2015-07-13	2016-01-01	2016-12-31
511.	CD6374	2015-07-28	2016-01-01	2016-12-31
512.	CD6400	2015-08-11	2016-01-01	2016-12-31
513.	CG2919	2015-10-13	2016-01-01	2016-12-31
514.	CG2921	2015-10-13	2016-01-01	2016-12-31
515.	CG2920	2015-10-13	2016-01-01	2016-12-31
516.	CG2909	2015-10-13	2016-01-01	2016-12-31
517.	CG2902	2015-10-13	2016-01-01	2016-12-31
518.	CG2910	2015-10-13	2016-01-01	2016-12-31
519.	CG2907	2015-10-13	2016-01-01	2016-12-31
520.	CG2904	2015-10-13	2016-01-01	2016-12-31
521.	CG2915	2015-10-13	2016-01-01	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
522.	CG2912	2015-10-13	2016-01-01	2016-12-31
523.	CG2903	2015-10-13	2016-01-01	2016-12-31
524.	CG2908	2015-10-13	2016-01-01	2016-12-31
525.	CG2905	2015-10-13	2016-01-01	2016-12-31
526.	CG2906	2015-10-13	2016-01-01	2016-12-31
527.	CG2914	2015-10-13	2016-01-01	2016-12-31
528.	CG2913	2015-10-13	2016-01-01	2016-12-31
529.	CG2916	2015-10-13	2016-01-01	2016-12-31
530.	CG2911	2015-10-13	2016-01-01	2016-12-31
531.	CG2918	2015-10-13	2016-01-01	2016-01-20
532.	CG2931	2015-12-21	2016-03-17	2016-12-31
533.	CH07528	2016-01-08	2016-03-17	2016-12-31
534.	CE01327	2016-01-18	2016-01-18	2016-12-31
535.	CE01328	2016-01-19	2016-01-18	2016-12-31
536.	CE01329	2016-01-20	2016-01-18	2016-12-31
537.	CE01326	2016-01-21	2016-01-18	2016-12-31
538.	CD6387	2016-01-29	2016-01-01	2016-12-31
539.	CG2946	2016-01-29	2016-01-01	2016-12-31
540.	CE01342	2016-02-02	2016-01-01	2016-12-31
541.	CE01331	2016-02-02	2016-01-25	2016-12-31
542.	CE01337	2016-02-02	2016-01-01	2016-12-31
543.	CE01333	2016-02-02	2016-01-25	2016-12-31
544.	CE01334	2016-02-02	2016-01-25	2016-12-31
545.	CE01335	2016-02-02	2016-01-25	2016-12-31
546.	CE01336	2016-02-02	2016-01-25	2016-12-31
547.	CE01332	2016-02-02	2016-01-25	2016-12-31
548.	CE01338	2016-02-02	2016-01-25	2016-12-31
549.	CE01339	2016-02-02	2016-01-25	2016-12-31
550.	CE01340	2016-02-02	2016-01-25	2016-12-31
551.	CE01341	2016-02-02	2016-01-25	2016-12-31
552.	CE01345	2016-02-02	2016-01-25	2016-12-31
553.	CE01344	2016-02-02	2016-01-25	2016-12-31
554.	CE01330	2016-02-02	2016-01-25	2016-12-31
555.	CE01343	2016-02-02	2016-01-25	2016-12-31
556.	CG2950	2016-02-05	2016-03-17	2016-12-31
557.	CH07508	2016-02-05	2016-01-01	2016-12-31
558.	CH07509	2016-02-05	2016-01-01	2016-12-31
559.	CG2951	2016-02-05	2016-02-29	2016-12-31
560.	CH07506	2016-02-09	2016-01-01	2016-12-31
561.	CH07507	2016-02-10	2016-01-01	2016-12-31
562.	CH07532	2016-02-25	2016-02-29	2016-12-31
563.	CH07531	2016-03-14	2016-02-29	2016-12-31
564.	CI9052	2016-04-05	2016-01-01	2016-12-31
565.	CI9053	2016-04-05	2016-02-22	2016-12-31
566.	CE01346	2016-04-05	2016-02-22	2016-12-31
567.	CI9051	2016-04-05	2016-02-22	2016-12-31
568.	CE01349	2016-04-05	2016-02-22	2016-12-31
569.	CE01347	2016-04-05	2016-02-22	2016-12-31
570.	CI9054	2016-04-05	2016-01-01	2016-12-31
571.	CE01348	2016-04-05	2016-02-22	2016-12-31
572.	CI9056	2016-04-05	2016-02-22	2016-12-31
573.	CI9060	2016-04-05	2016-02-22	2016-12-31
574.	CI9057	2016-04-05	2016-02-22	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
575.	CI9058	2016-04-05	2016-02-22	2016-12-31
576.	CI9061	2016-04-05	2016-01-01	2016-12-31
577.	CI9055	2016-04-05	2016-02-22	2016-12-31
578.	CE01350	2016-04-05	2016-02-22	2016-12-31
579.	CI9059	2016-04-05	2016-02-22	2016-12-31
580.	CI9065	2016-04-28	2016-04-04	2016-12-31
581.	CI9064	2016-04-28	2016-04-04	2016-12-31
582.	CI9062	2016-04-28	2016-04-04	2016-12-31
583.	CI9066	2016-04-28	2016-01-01	2016-12-31
584.	CI9063	2016-04-28	2016-04-04	2016-12-31
585.	CI9071	2016-04-28	2016-04-04	2016-12-31
586.	CI9077	2016-04-28	2016-04-04	2016-12-31
587.	CI9075	2016-04-28	2016-04-04	2016-12-31
588.	CI9074	2016-04-28	2016-04-04	2016-12-31
589.	CI9073	2016-04-28	2016-04-04	2016-12-31
590.	CI9076	2016-04-28	2016-04-04	2016-12-31
591.	CI9072	2016-04-28	2016-04-04	2016-12-31
592.	CI9068	2016-04-28	2016-04-04	2016-12-31
593.	CI9070	2016-04-28	2016-04-04	2016-12-31
594.	CI9069	2016-04-28	2016-04-04	2016-12-31
595.	CH07146	2016-05-02	2016-02-29	2016-12-31
596.	CH07527	2016-05-02	2016-02-29	2016-12-31
597.	CB4338	2016-05-02	2016-02-29	2016-12-31
598.	CH07539	2016-05-02	2016-02-29	2016-12-31
599.	CH07144	2016-05-02	2016-02-29	2016-12-31
600.	CH07145	2016-05-02	2016-02-29	2016-12-31
601.	CH07538	2016-05-02	2016-02-29	2016-12-31
602.	CH07142	2016-05-02	2016-02-29	2016-12-31
603.	CH07536	2016-05-02	2016-02-29	2016-12-31
604.	CH07540	2016-05-02	2016-02-29	2016-12-31
605.	CH07535	2016-05-02	2016-02-29	2016-12-31
606.	CH07147	2016-05-10	2016-03-17	2016-12-31
607.	CH07148	2016-05-10	2016-03-17	2016-12-31
608.	CI9106	2016-05-24	2016-04-25	2016-12-31
609.	CI9100	2016-05-24	2016-04-25	2016-12-31
610.	CI9101	2016-05-24	2016-01-01	2016-12-31
611.	CI9094	2016-05-24	2016-04-25	2016-12-31
612.	CI9095	2016-05-24	2016-04-25	2016-12-31
613.	CI9096	2016-05-24	2016-04-25	2016-12-31
614.	CI9097	2016-05-24	2016-04-25	2016-12-31
615.	CI9099	2016-05-24	2016-04-25	2016-12-31
616.	CI9092	2016-05-24	2016-04-25	2016-12-31
617.	CI9093	2016-05-24	2016-04-25	2016-12-31
618.	CI9107	2016-05-24	2016-04-25	2016-12-31
619.	CI9098	2016-05-24	2016-04-25	2016-12-31
620.	CI9105	2016-05-24	2016-01-01	2016-12-31
621.	CI9102	2016-05-24	2016-04-25	2016-12-31
622.	CI9103	2016-05-24	2016-04-25	2016-12-31
623.	CI9104	2016-05-24	2016-04-25	2016-12-31
624.	CH07154	2016-05-25	2016-04-14	2016-12-31
625.	CH07534	2016-05-25	2016-02-29	2016-12-31
626.	CB4339	2016-05-25	2016-02-29	2016-12-31
627.	CH07141	2016-05-25	2016-02-29	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
628.	CI9127	2016-06-17	2016-05-30	2016-12-31
629.	CI9128	2016-06-17	2016-05-30	2016-12-31
630.	CI9129	2016-06-17	2016-05-30	2016-12-31
631.	CI9130	2016-06-17	2016-01-01	2016-12-31
632.	CI9131	2016-06-17	2016-05-30	2016-12-31
633.	CI9132	2016-06-17	2016-05-30	2016-12-31
634.	CI9133	2016-06-17	2016-05-30	2016-12-31
635.	CI9134	2016-06-17	2016-02-11	2016-12-31
636.	CI9135	2016-06-17	2016-05-30	2016-12-31
637.	CI9136	2016-06-17	2016-05-30	2016-12-31
638.	CI9137	2016-06-17	2016-05-30	2016-12-31
639.	CI9138	2016-06-17	2016-05-30	2016-12-31
640.	CI9139	2016-06-17	2016-05-30	2016-12-31
641.	CI9140	2016-06-17	2016-05-30	2016-12-31
642.	CI9141	2016-06-17	2016-05-30	2016-12-31
643.	CI9142	2016-06-17	2016-05-30	2016-12-31
644.	CI9143	2016-06-17	2016-05-30	2016-12-31
645.	CI9144	2016-06-17	2016-05-30	2016-12-31
646.	CI9110	2016-06-17	2016-05-30	2016-12-31
647.	CI9109	2016-06-17	2016-05-30	2016-12-31
648.	CI9126	2016-06-17	2016-05-30	2016-12-31
649.	CI9117	2016-06-17	2016-05-30	2016-12-31
650.	CI9125	2016-06-17	2016-05-30	2016-12-31
651.	CI9124	2016-06-17	2016-05-30	2016-12-31
652.	CI9123	2016-06-17	2016-01-01	2016-12-31
653.	CI9122	2016-06-17	2016-05-30	2016-12-31
654.	CI9121	2016-06-17	2016-05-30	2016-12-31
655.	CI9120	2016-06-17	2016-05-30	2016-12-31
656.	CI9118	2016-06-17	2016-05-30	2016-12-31
657.	CI9116	2016-06-17	2016-05-30	2016-12-31
658.	CI9115	2016-06-17	2016-05-30	2016-12-31
659.	CI9114	2016-06-17	2016-05-30	2016-12-31
660.	CI9113	2016-06-17	2016-05-30	2016-12-31
661.	CI9112	2016-06-17	2016-01-01	2016-12-31
662.	CI9111	2016-06-17	2016-05-30	2016-12-31
663.	CI9119	2016-06-17	2016-05-30	2016-12-31
664.	CI9108	2016-06-17	2016-05-30	2016-12-31
665.	CH07164	2016-07-08	2016-10-27	2016-12-31
666.	CJ1959	2016-10-27	2016-10-27	2016-12-31
667.	CH07166	2016-11-18	2016-06-13	2016-12-31
668.	CJ1943	2016-11-18	2016-08-29	2016-12-31
669.	CI9173	2016-12-01	2016-11-28	2016-12-31
670.	CI9166	2016-12-01	2016-11-28	2016-12-31
671.	CI9163	2016-12-01	2016-11-28	2016-12-31
672.	CI9162	2016-12-01	2016-11-28	2016-12-31
673.	CI9161	2016-12-01	2016-11-28	2016-12-31
674.	CI9160	2016-12-01	2016-11-28	2016-12-31
675.	CI9174	2016-12-01	2016-05-30	2016-12-31
676.	CI9172	2016-12-01	2016-11-28	2016-12-31
677.	CI9171	2016-12-01	2016-11-28	2016-12-31
678.	CI9170	2016-12-01	2016-11-28	2016-12-31
679.	CI9169	2016-12-01	2016-11-28	2016-12-31
680.	CI9165	2016-12-01	2016-11-28	2016-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
681.	CI9168	2016-12-01	2016-11-28	2016-12-31
682.	CI9164	2016-12-01	2016-11-28	2016-12-31
683.	CI9167	2016-12-01	2016-01-01	2016-12-31
684.	CJ1946	2016-12-07	2016-06-13	2016-12-31
685.	PE3496	2013-02-25	2016-01-01	2016-12-31
686.	CB8090	2014-05-26	2016-01-01	2016-12-31
687.	CB8093	2014-05-26	2016-01-01	2016-12-31
688.	CE01300	2015-07-13	2016-01-01	2016-12-31
689.	CE01304	2015-07-13	2016-01-01	2016-12-31
690.	CE01298	2015-07-13	2016-01-01	2016-12-31
691.	CE01299	2015-07-13	2016-01-01	2016-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.	25		683
2.	29		792
3.	29		792
4.	29		792
5.	29		792
6.	29		792
7.	29		792
8.	29		792
9.	29		792
10.	29		792
11.	29		792
12.	29		792
13.	29		792
14.	29		792
15.	29		792
16.	29		792
17.	36		984
18.	36		984
19.	57		1,557
20.	57		1,557
21.	57		1,557
22.	57		1,557
23.	57		1,557
24.	57		1,557
25.	57		1,557
26.	57		1,557
27.	57		1,557
28.	57		1,557
29.	20		546
30.	57		1,557
31.	57		1,557
32.	57		1,557
33.	57		1,557
34.	57		1,557
35.	57		1,557
36.	63		1,721
37.	88		2,404
38.	15		410
39.	88		2,404
40.	88		2,404
41.	82		2,240
42.	109		2,978
43.	124		3,388
44.	128		3,497
45.	128		3,497
46.	126		3,443
47.	128		3,497
48.	128		3,497
49.	128		3,497
50.	95		2,596
51.	128		3,497
52.	4		109

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
53.	64		1,749
54.	26		710
55.	148		4,044
56.	67		1,831
57.	148		4,044
58.	148		4,044
59.	148		4,044
60.	148		4,044
61.	148		4,044
62.	148		4,044
63.	148		4,044
64.	148		4,044
65.	148		4,044
66.	148		4,044
67.	148		4,044
68.	207		5,656
69.	235		6,421
70.	235		6,421
71.	235		6,421
72.	235		6,421
73.	90		2,459
74.	85		2,322
75.	288		7,869
76.	288		7,869
77.	288		7,869
78.	288		7,869
79.	288		7,869
80.	288		7,869
81.	312		8,525
82.	229		6,257
83.	167		4,563
84.	235		6,421
85.	257		7,022
86.	103		2,814
87.	291		7,951
88.	313		8,552
89.	256		6,995
90.	317		8,661
91.	345		9,426
92.	211		5,765
93.	155		4,235
94.	90		2,459
95.	366		10,000
96.	4		109
97.	185		5,055
98.	366		10,000
99.	302		8,251
100.	366		10,000
101.	366		10,000
102.	366		10,000
103.	366		10,000
104.	366		10,000
105.	366		10,000
106.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
107.	186		5,082
108.	9		246
109.	366		10,000
110.	366		10,000
111.	366		10,000
112.	366		10,000
113.	366		10,000
114.	366		10,000
115.	366		10,000
116.	366		10,000
117.	237		6,475
118.	366		10,000
119.	366		10,000
120.	366		10,000
121.	366		10,000
122.	366		10,000
123.	366		10,000
124.	366		10,000
125.	366		10,000
126.	366		10,000
127.	366		10,000
128.	280		7,650
129.	366		10,000
130.	366		10,000
131.	366		10,000
132.	366		10,000
133.	366		10,000
134.	366		10,000
135.	366		10,000
136.	366		10,000
137.	366		10,000
138.	366		10,000
139.	366		10,000
140.	366		10,000
141.	366		10,000
142.	366		10,000
143.	224		6,120
144.	366		10,000
145.	366		10,000
146.	366		10,000
147.	366		10,000
148.	366		10,000
149.	366		10,000
150.	366		10,000
151.	366		10,000
152.	366		10,000
153.	366		10,000
154.	366		10,000
155.	366		10,000
156.	366		10,000
157.	366		10,000
158.	366		10,000
159.	366		10,000
160.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
161.	366		10,000
162.	169		4,617
163.	312		8,525
164.	366		10,000
165.	366		10,000
166.	366		10,000
167.	366		10,000
168.	366		10,000
169.	366		10,000
170.	366		10,000
171.	366		10,000
172.	366		10,000
173.	366		10,000
174.	366		10,000
175.	366		10,000
176.	366		10,000
177.	366		10,000
178.	366		10,000
179.	366		10,000
180.	366		10,000
181.	18		492
182.	366		10,000
183.	366		10,000
184.	366		10,000
185.	366		10,000
186.	366		10,000
187.	366		10,000
188.	366		10,000
189.	366		10,000
190.	366		10,000
191.	366		10,000
192.	366		10,000
193.	366		10,000
194.	366		10,000
195.	366		10,000
196.	366		10,000
197.	307		8,388
198.	366		10,000
199.	366		10,000
200.	366		10,000
201.	299		8,169
202.	277		7,568
203.	366		10,000
204.	366		10,000
205.	366		10,000
206.	366		10,000
207.	366		10,000
208.	366		10,000
209.	13		355
210.	366		10,000
211.	366		10,000
212.	366		10,000
213.	366		10,000
214.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
215.	366		10,000
216.	256		6,995
217.	366		10,000
218.	366		10,000
219.	155		4,235
220.	366		10,000
221.	366		10,000
222.	366		10,000
223.	366		10,000
224.	366		10,000
225.	366		10,000
226.	40		1,093
227.	366		10,000
228.	366		10,000
229.	97		2,650
230.	366		10,000
231.	366		10,000
232.	366		10,000
233.	366		10,000
234.	366		10,000
235.	366		10,000
236.	366		10,000
237.	366		10,000
238.	366		10,000
239.	145		3,962
240.	186		5,082
241.	277		7,568
242.	161		4,399
243.	115		3,142
244.	156		4,262
245.	366		10,000
246.	366		10,000
247.	366		10,000
248.	366		10,000
249.	366		10,000
250.	366		10,000
251.	366		10,000
252.	366		10,000
253.	366		10,000
254.	366		10,000
255.	366		10,000
256.	366		10,000
257.	366		10,000
258.	366		10,000
259.	366		10,000
260.	366		10,000
261.	366		10,000
262.	366		10,000
263.	366		10,000
264.	366		10,000
265.	366		10,000
266.	366		10,000
267.	366		10,000
268.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
269.	366		10,000
270.	366		10,000
271.	366		10,000
272.	366		10,000
273.	366		10,000
274.	366		10,000
275.	366		10,000
276.	366		10,000
277.	275		7,514
278.	366		10,000
279.	366		10,000
280.	366		10,000
281.	366		10,000
282.	366		10,000
283.	366		10,000
284.	366		10,000
285.	366		10,000
286.	366		10,000
287.	366		10,000
288.	366		10,000
289.	366		10,000
290.	366		10,000
291.	366		10,000
292.	366		10,000
293.	366		10,000
294.	366		10,000
295.	366		10,000
296.	366		10,000
297.	366		10,000
298.	366		10,000
299.	258		7,049
300.	366		10,000
301.	366		10,000
302.	366		10,000
303.	101		2,760
304.	366		10,000
305.	366		10,000
306.	366		10,000
307.	366		10,000
308.	366		10,000
309.	366		10,000
310.	366		10,000
311.	366		10,000
312.	366		10,000
313.	366		10,000
314.	366		10,000
315.	366		10,000
316.	366		10,000
317.	366		10,000
318.	366		10,000
319.	366		10,000
320.	195		5,328
321.	366		10,000
322.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
323.	366		10,000
324.	366		10,000
325.	366		10,000
326.	366		10,000
327.	366		10,000
328.	366		10,000
329.	366		10,000
330.	366		10,000
331.	366		10,000
332.	366		10,000
333.	366		10,000
334.	366		10,000
335.	366		10,000
336.	366		10,000
337.	366		10,000
338.	366		10,000
339.	301		8,224
340.	366		10,000
341.	366		10,000
342.	366		10,000
343.	366		10,000
344.	366		10,000
345.	366		10,000
346.	366		10,000
347.	366		10,000
348.	366		10,000
349.	366		10,000
350.	366		10,000
351.	366		10,000
352.	366		10,000
353.	366		10,000
354.	366		10,000
355.	366		10,000
356.	366		10,000
357.	16		437
358.	366		10,000
359.	366		10,000
360.	366		10,000
361.	366		10,000
362.	366		10,000
363.	366		10,000
364.	366		10,000
365.	366		10,000
366.	366		10,000
367.	366		10,000
368.	366		10,000
369.	366		10,000
370.	366		10,000
371.	366		10,000
372.	366		10,000
373.	366		10,000
374.	366		10,000
375.	366		10,000
376.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
377.	366		10,000
378.	366		10,000
379.	366		10,000
380.	366		10,000
381.	366		10,000
382.	366		10,000
383.	366		10,000
384.	366		10,000
385.	366		10,000
386.	366		10,000
387.	50		1,366
388.	366		10,000
389.	216		5,902
390.	366		10,000
391.	366		10,000
392.	366		10,000
393.	366		10,000
394.	366		10,000
395.	366		10,000
396.	366		10,000
397.	366		10,000
398.	356		9,727
399.	366		10,000
400.	366		10,000
401.	366		10,000
402.	366		10,000
403.	366		10,000
404.	366		10,000
405.	366		10,000
406.	366		10,000
407.	366		10,000
408.	366		10,000
409.	366		10,000
410.	366		10,000
411.	366		10,000
412.	366		10,000
413.	366		10,000
414.	366		10,000
415.	366		10,000
416.	366		10,000
417.	366		10,000
418.	366		10,000
419.	366		10,000
420.	366		10,000
421.	366		10,000
422.	366		10,000
423.	366		10,000
424.	366		10,000
425.	67		1,831
426.	366		10,000
427.	366		10,000
428.	366		10,000
429.	366		10,000
430.	366		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
431.	366		10,000
432.	366		10,000
433.	366		10,000
434.	366		10,000
435.	366		10,000
436.	366		10,000
437.	366		10,000
438.	366		10,000
439.	366		10,000
440.	366		10,000
441.	366		10,000
442.	366		10,000
443.	366		10,000
444.	366		10,000
445.	366		10,000
446.	366		10,000
447.	366		10,000
448.	92		2,514
449.	366		10,000
450.	366		10,000
451.	366		10,000
452.	293		8,005
453.	366		10,000
454.	366		10,000
455.	366		10,000
456.	366		10,000
457.	366		10,000
458.	366		10,000
459.	366		10,000
460.	366		10,000
461.	366		10,000
462.	366		10,000
463.	366		10,000
464.	366		10,000
465.	245		6,694
466.		366	5,000
467.		366	5,000
468.		366	5,000
469.		366	5,000
470.		366	5,000
471.		366	5,000
472.		366	5,000
473.		366	5,000
474.		366	5,000
475.		366	5,000
476.		366	5,000
477.		366	5,000
478.		366	5,000
479.		366	5,000
480.		366	5,000
481.		366	5,000
482.		366	5,000
483.		366	5,000
484.		366	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
485.		366	5,000
486.		366	5,000
487.		366	5,000
488.		225	3,074
489.		366	5,000
490.		366	5,000
491.		366	5,000
492.		366	5,000
493.		366	5,000
494.		366	5,000
495.		366	5,000
496.		366	5,000
497.		366	5,000
498.		366	5,000
499.		366	5,000
500.		366	5,000
501.		366	5,000
502.		366	5,000
503.		366	5,000
504.		366	5,000
505.		366	5,000
506.		366	5,000
507.		366	5,000
508.		366	5,000
509.		366	5,000
510.		366	5,000
511.		366	5,000
512.		366	5,000
513.		366	5,000
514.		366	5,000
515.		366	5,000
516.		366	5,000
517.		366	5,000
518.		366	5,000
519.		366	5,000
520.		366	5,000
521.		366	5,000
522.		366	5,000
523.		366	5,000
524.		366	5,000
525.		366	5,000
526.		366	5,000
527.		366	5,000
528.		366	5,000
529.		366	5,000
530.		366	5,000
531.		20	273
532.		290	3,962
533.		290	3,962
534.		349	4,768
535.		349	4,768
536.		349	4,768
537.		349	4,768
538.		366	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
539.		366	5,000
540.		366	5,000
541.		342	4,672
542.		366	5,000
543.		342	4,672
544.		342	4,672
545.		342	4,672
546.		342	4,672
547.		342	4,672
548.		342	4,672
549.		342	4,672
550.		342	4,672
551.		342	4,672
552.		342	4,672
553.		342	4,672
554.		342	4,672
555.		342	4,672
556.		290	3,962
557.		366	5,000
558.		366	5,000
559.		307	4,194
560.		366	5,000
561.		366	5,000
562.		307	4,194
563.		307	4,194
564.		366	5,000
565.		314	4,290
566.		314	4,290
567.		314	4,290
568.		314	4,290
569.		314	4,290
570.		366	5,000
571.		314	4,290
572.		314	4,290
573.		314	4,290
574.		314	4,290
575.		314	4,290
576.		366	5,000
577.		314	4,290
578.		314	4,290
579.		314	4,290
580.		272	3,716
581.		272	3,716
582.		272	3,716
583.		366	5,000
584.		272	3,716
585.		272	3,716
586.		272	3,716
587.		272	3,716
588.		272	3,716
589.		272	3,716
590.		272	3,716
591.		272	3,716
592.		272	3,716

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
593.		272	3,716
594.		272	3,716
595.		307	4,194
596.		307	4,194
597.		307	4,194
598.		307	4,194
599.		307	4,194
600.		307	4,194
601.		307	4,194
602.		307	4,194
603.		307	4,194
604.		307	4,194
605.		307	4,194
606.		290	3,962
607.		290	3,962
608.		251	3,429
609.		251	3,429
610.		366	5,000
611.		251	3,429
612.		251	3,429
613.		251	3,429
614.		251	3,429
615.		251	3,429
616.		251	3,429
617.		251	3,429
618.		251	3,429
619.		251	3,429
620.		366	5,000
621.		251	3,429
622.		251	3,429
623.		251	3,429
624.		262	3,579
625.		307	4,194
626.		307	4,194
627.		307	4,194
628.		216	2,951
629.		216	2,951
630.		216	2,951
631.		366	5,000
632.		216	2,951
633.		216	2,951
634.		216	2,951
635.		325	4,440
636.		216	2,951
637.		216	2,951
638.		216	2,951
639.		216	2,951
640.		216	2,951
641.		216	2,951
642.		216	2,951
643.		216	2,951
644.		216	2,951
645.		216	2,951
646.		216	2,951

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
647.		216	2,951
648.		216	2,951
649.		216	2,951
650.		216	2,951
651.		216	2,951
652.		366	5,000
653.		216	2,951
654.		216	2,951
655.		216	2,951
656.		216	2,951
657.		216	2,951
658.		216	2,951
659.		216	2,951
660.		216	2,951
661.		366	5,000
662.		216	2,951
663.		216	2,951
664.		216	2,951
665.		66	902
666.		66	902
667.		202	2,760
668.		125	1,708
669.		34	464
670.		34	464
671.		34	464
672.		34	464
673.		34	464
674.		34	464
675.		216	2,951
676.		34	464
677.		34	464
678.		34	464
679.		34	464
680.		34	464
681.		34	464
682.		34	464
683.		366	5,000
684.		202	2,760
685.	366		10,000
686.	366		10,000
687.	366		10,000
688.		366	5,000
689.		366	5,000
690.		366	5,000
691.		366	5,000

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*) or ($5,000 × H2/365*), whichever applies.
* 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.	66,978		23,442
2.	97,663		34,182
3.	102,976		36,042
4.	123,627		43,269
5.	102,922		36,023
6.	105,939		37,079
7.	95,237		33,333
8.	105,191		36,817
9.	107,237		37,533
10.	114,026		39,909
11.	87,167		30,508
12.	114,824		40,188
13.	108,037		37,813
14.	112,291		39,302
15.	84,049		29,417
16.	89,619		31,367
17.	115,485		40,420
18.	86,134		30,147
19.	81,391		28,487
20.	92,770		32,470
21.	94,637		33,123
22.	120,558		42,195
23.	103,989		36,396
24.	106,626		37,319
25.	99,523		34,833
26.	62,049		21,717
27.	102,398		35,839
28.	88,961		31,136
29.	125,792		44,027
30.	92,636		32,423
31.	72,085		25,230
32.	105,831		37,041
33.	67,456		23,610
34.	85,101		29,785
35.	98,530		34,486
36.	6,752		2,363
37.	83,593		29,258
38.	102,679		35,938
39.	53,738		18,808
40.	73,676		25,787
41.	79,421		27,797
42.	26,366		9,228
43.	54,871		19,205
44.	113,455		39,709
45.	71,175		24,911
46.	30,429		10,650
47.	108,373		37,931
48.	107,385		37,585
49.	83,551		29,243
50.	86,289		30,201
51.	118,668		41,534
52.	73,063		25,572
53.	73,063		25,572
54.	96,012		33,604

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
55.	90,643		31,725
56.	99,663		34,882
57.	94,379		33,033
58.	106,425		37,249
59.	83,216		29,126
60.	101,307		35,457
61.	109,495		38,323
62.	91,785		32,125
63.	99,116		34,691
64.	28,567		9,998
65.	86,909		30,418
66.	82,827		28,989
67.	95,041		33,264
68.	78,510		27,479
69.	76,829		26,890
70.	59,470		20,815
71.	60,786		21,275
72.	126,300		44,205
73.	97,654		34,179
74.	34,847		12,196
75.	52,210		18,274
76.	52,769		18,469
77.	54,978		19,242
78.	48,198		16,869
79.	52,645		18,426
80.	71,958		25,185
81.	75,011		26,254
82.	88,651		31,028
83.	90,522		31,683
84.	107,831		37,741
85.	95,171		33,310
86.	99,327		34,764
87.	97,584		34,154
88.	77,721		27,202
89.	106,984		37,444
90.	73,049		25,567
91.	66,359		23,226
92.	85,099		29,785
93.	81,180		28,413
94.	101,413		35,495
95.	105,044		36,765
96.	119,679		41,888
97.	119,679		41,888
98.	46,519		16,282
99.	134,100		46,935
100.	125,026		43,759
101.	89,974		31,491
102.	138,797		48,579
103.	90,643		31,725
104.	121,101		42,385
105.	86,784		30,374
106.	102,208		35,773
107.	109,952		38,483
108.	109,952		38,483

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
109.	82,083		28,729
110.	102,611		35,914
111.	79,230		27,731
112.	87,297		30,554
113.	142,412		49,844
114.	107,409		37,593
115.	79,424		27,798
116.	82,881		29,008
117.	36,905		12,917
118.	88,842		31,095
119.	83,312		29,159
120.	72,320		25,312
121.	82,282		28,799
122.	83,876		29,357
123.	108,595		38,008
124.	103,223		36,128
125.	93,517		32,731
126.	81,191		28,417
127.	116,492		40,772
128.	57,355		20,074
129.	105,173		36,811
130.	102,557		35,895
131.	133,293		46,653
132.	87,613		30,665
133.	90,571		31,700
134.	78,540		27,489
135.	88,536		30,988
136.	106,968		37,439
137.	90,744		31,760
138.	64,666		22,633
139.	84,924		29,723
140.	93,981		32,893
141.	73,053		25,569
142.	75,206		26,322
143.	51,360		17,976
144.	133,811		46,834
145.	132,067		46,223
146.	96,901		33,915
147.	109,762		38,417
148.	76,974		26,941
149.	72,559		25,396
150.	99,913		34,970
151.	91,145		31,901
152.	82,009		28,703
153.	76,225		26,679
154.	91,954		32,184
155.	92,957		32,535
156.	94,225		32,979
157.	110,503		38,676
158.	75,529		26,435
159.	82,273		28,796
160.	94,268		32,994
161.	88,150		30,853
162.	109,307		38,257

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	**J2** Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	**K** Eligible expenditures **multiplied** by specified percentage (see note 4) 460
163.	70,952		24,833
164.	74,453		26,059
165.	80,024		28,008
166.	62,265		21,793
167.	82,513		28,880
168.	42,243		14,785
169.	61,878		21,657
170.	70,953		24,834
171.	82,976		29,042
172.	58,667		20,533
173.	60,484		21,169
174.	87,350		30,573
175.	67,110		23,489
176.	81,724		28,603
177.	61,551		21,543
178.	74,619		26,117
179.	82,774		28,971
180.	74,471		26,065
181.	140,030		49,011
182.	105,221		36,827
183.	73,350		25,673
184.	72,930		25,526
185.	73,775		25,821
186.	64,154		22,454
187.	67,716		23,701
188.	50,359		17,626
189.	54,187		18,965
190.	44,827		15,689
191.	54,136		18,948
192.	48,007		16,802
193.	66,038		23,113
194.	42,600		14,910
195.	80,187		28,065
196.	67,397		23,589
197.	56,484		19,769
198.	90,236		31,583
199.	76,308		26,708
200.	86,630		30,321
201.	83,203		29,121
202.	88,058		30,820
203.	81,308		28,458
204.	81,814		28,635
205.	45,707		15,997
206.	67,987		23,795
207.	78,300		27,405
208.	87,669		30,684
209.	106,292		37,202
210.	86,218		30,176
211.	64,767		22,668
212.	42,381		14,833
213.	53,242		18,635
214.	58,600		20,510
215.	60,235		21,082
216.	55,496		19,424

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
217.	48,486		16,970
218.	47,916		16,771
219.	73,433		25,702
220.	62,307		21,807
221.	58,302		20,406
222.	55,371		19,380
223.	61,736		21,608
224.	58,833		20,592
225.	52,238		18,283
226.	89,625		31,369
227.	91,054		31,869
228.	71,597		25,059
229.	61,443		21,505
230.	94,177		32,962
231.	43,931		15,376
232.	48,414		16,945
233.	48,215		16,875
234.	50,383		17,634
235.	53,469		18,714
236.	66,046		23,116
237.	65,768		23,019
238.	71,213		24,925
239.	85,659		29,981
240.	124,019		43,407
241.	88,615		31,015
242.	81,325		28,464
243.	94,232		32,981
244.	94,232		32,981
245.	54,479		19,068
246.	67,787		23,725
247.	75,792		26,527
248.	76,192		26,667
249.	73,618		25,766
250.	91,696		32,094
251.	84,785		29,675
252.	79,961		27,986
253.	70,440		24,654
254.	71,448		25,007
255.	79,924		27,973
256.	72,022		25,208
257.	78,463		27,462
258.	77,381		27,083
259.	65,272		22,845
260.	76,503		26,776
261.	72,134		25,247
262.	55,160		19,306
263.	77,637		27,173
264.	77,671		27,185
265.	65,362		22,877
266.	63,293		22,153
267.	74,141		25,949
268.	72,172		25,260
269.	71,213		24,925
270.	105,499		36,925

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
271.	76,753		26,864
272.	73,917		25,871
273.	86,022		30,108
274.	68,051		23,818
275.	73,675		25,786
276.	75,425		26,399
277.	62,406		21,842
278.	58,458		20,460
279.	78,197		27,369
280.	75,858		26,550
281.	50,032		17,511
282.	57,426		20,099
283.	43,419		15,197
284.	72,652		25,428
285.	78,173		27,361
286.	85,724		30,003
287.	88,516		30,981
288.	76,507		26,777
289.	69,865		24,453
290.	77,758		27,215
291.	74,901		26,215
292.	78,231		27,381
293.	73,339		25,669
294.	81,753		28,614
295.	75,914		26,570
296.	65,134		22,797
297.	72,257		25,290
298.	78,226		27,379
299.	45,121		15,792
300.	53,327		18,664
301.	57,120		19,992
302.	73,074		25,576
303.	16,145		5,651
304.	45,528		15,935
305.	37,945		13,281
306.	65,928		23,075
307.	70,948		24,832
308.	67,667		23,683
309.	62,554		21,894
310.	41,894		14,663
311.	53,552		18,743
312.	45,647		15,976
313.	39,835		13,942
314.	46,542		16,290
315.	55,480		19,418
316.	54,574		19,101
317.	60,989		21,346
318.	63,320		22,162
319.	76,277		26,697
320.	59,491		20,822
321.	68,656		24,030
322.	66,884		23,409
323.	63,957		22,385
324.	74,687		26,140

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
325.	66,814		23,385
326.	88,837		31,093
327.	75,283		26,349
328.	76,722		26,853
329.	65,483		22,919
330.	77,648		27,177
331.	75,332		26,366
332.	73,496		25,724
333.	75,896		26,564
334.	73,823		25,838
335.	74,027		25,909
336.	74,165		25,958
337.	35,035		12,262
338.	40,918		14,321
339.	79,292		27,752
340.	47,725		16,704
341.	43,837		15,343
342.	42,348		14,822
343.	39,556		13,845
344.	46,141		16,149
345.	41,638		14,573
346.	37,941		13,279
347.	52,552		18,393
348.	52,176		18,262
349.	76,163		26,657
350.	63,506		22,227
351.	42,241		14,784
352.	78,664		27,532
353.	56,547		19,791
354.	69,055		24,169
355.	52,164		18,257
356.	50,104		17,536
357.	50,440		17,654
358.	48,817		17,086
359.	53,257		18,640
360.	54,570		19,100
361.	59,168		20,709
362.	61,360		21,476
363.	63,410		22,194
364.	59,767		20,918
365.	66,055		23,119
366.	71,977		25,192
367.	88,214		30,875
368.	59,254		20,739
369.	71,283		24,949
370.	70,841		24,794
371.	80,869		28,304
372.	74,025		25,909
373.	44,620		15,617
374.	72,287		25,300
375.	84,520		29,582
376.	66,015		23,105
377.	92,161		32,256
378.	65,573		22,951

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
379.	74,839		26,194
380.	64,214		22,475
381.	42,687		14,940
382.	42,061		14,721
383.	49,088		17,181
384.	57,722		20,203
385.	46,929		16,425
386.	64,066		22,423
387.	103,024		36,058
388.	74,723		26,153
389.	27,183		9,514
390.	123,378		43,182
391.	79,987		27,995
392.	141,317		49,461
393.	122,599		42,910
394.	81,964		28,687
395.	80,290		28,102
396.	77,257		27,040
397.	93,175		32,611
398.	46,012		16,104
399.	105,085		36,780
400.	58,585		20,505
401.	42,916		15,021
402.	27,823		9,738
403.	75,725		26,504
404.	51,170		17,910
405.	49,242		17,235
406.	48,167		16,858
407.	58,904		20,616
408.	64,440		22,554
409.	57,577		20,152
410.	79,538		27,838
411.	68,392		23,937
412.	61,637		21,573
413.	55,754		19,514
414.	57,180		20,013
415.	69,653		24,379
416.	67,063		23,472
417.	58,113		20,340
418.	60,521		21,182
419.	55,807		19,532
420.	76,505		26,777
421.	63,352		22,173
422.	63,511		22,229
423.	57,962		20,287
424.	72,067		25,223
425.	45,418		15,896
426.	62,754		21,964
427.	77,387		27,085
428.	63,550		22,243
429.	68,005		23,802
430.	56,913		19,920
431.	58,708		20,548
432.	71,937		25,178

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
433.	60,155		21,054
434.	58,547		20,491
435.	59,076		20,677
436.	65,281		22,848
437.	55,324		19,363
438.	66,140		23,149
439.	54,078		18,927
440.	73,168		25,609
441.	71,342		24,970
442.	72,545		25,391
443.	67,282		23,549
444.	63,533		22,237
445.	65,896		23,064
446.	62,932		22,026
447.	59,458		20,810
448.	2,091		732
449.	65,767		23,018
450.	46,124		16,143
451.	79,727		27,904
452.	45,559		15,946
453.	63,663		22,282
454.	61,178		21,412
455.	69,465		24,313
456.	66,630		23,321
457.	65,594		22,958
458.	62,535		21,887
459.	67,570		23,650
460.	67,288		23,551
461.	63,940		22,379
462.	61,486		21,520
463.	66,957		23,435
464.	57,809		20,233
465.	36,618		12,816
466.		64,208	16,052
467.		59,925	14,981
468.		42,928	10,732
469.		42,202	10,551
470.		49,131	12,283
471.		49,171	12,293
472.		74,879	18,720
473.		38,147	9,537
474.		57,885	14,471
475.		43,593	10,898
476.		59,792	14,948
477.		56,531	14,133
478.		49,780	12,445
479.		55,511	13,878
480.		56,431	14,108
481.		65,484	16,371
482.		41,533	10,383
483.		69,360	17,340
484.		62,792	15,698
485.		62,965	15,741
486.		69,492	17,373

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
487.		60,865	15,216
488.		32,728	8,182
489.		62,339	15,585
490.		51,341	12,835
491.		53,727	13,432
492.		59,112	14,778
493.		60,413	15,103
494.		73,738	18,435
495.		66,459	16,615
496.		64,628	16,157
497.		61,036	15,259
498.		65,008	16,252
499.		73,915	18,479
500.		63,699	15,925
501.		62,590	15,648
502.		56,695	14,174
503.		57,214	14,304
504.		55,731	13,933
505.		66,356	16,589
506.		63,260	15,815
507.		55,677	13,919
508.		57,729	14,432
509.		59,681	14,920
510.		60,850	15,213
511.		74,614	18,654
512.		64,763	16,191
513.		38,460	9,615
514.		37,611	9,403
515.		53,463	13,366
516.		52,543	13,136
517.		51,352	12,838
518.		59,490	14,873
519.		44,177	11,044
520.		53,235	13,309
521.		49,873	12,468
522.		72,053	18,013
523.		54,821	13,705
524.		66,878	16,720
525.		50,928	12,732
526.		72,812	18,203
527.		51,119	12,780
528.		60,478	15,120
529.		61,622	15,406
530.		53,945	13,486
531.		2,776	694
532.		37,891	9,473
533.		30,733	7,683
534.		48,964	12,241
535.		40,474	10,119
536.		56,275	14,069
537.		39,035	9,759
538.		62,810	15,703
539.		52,049	13,012
540.		49,208	12,302

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
541.		47,900	11,975
542.		49,622	12,406
543.		57,138	14,285
544.		52,874	13,219
545.		47,934	11,984
546.		49,856	12,464
547.		44,821	11,205
548.		48,672	12,168
549.		47,400	11,850
550.		61,099	15,275
551.		47,738	11,935
552.		52,021	13,005
553.		48,307	12,077
554.		58,028	14,507
555.		58,254	14,564
556.		36,132	9,033
557.		38,595	9,649
558.		46,782	11,696
559.		36,702	9,176
560.		50,100	12,525
561.		41,242	10,311
562.		36,571	9,143
563.		33,098	8,275
564.		58,634	14,659
565.		52,208	13,052
566.		53,333	13,333
567.		50,158	12,540
568.		44,963	11,241
569.		66,828	16,707
570.		45,152	11,288
571.		56,442	14,111
572.		62,213	15,553
573.		55,852	13,963
574.		51,562	12,891
575.		52,544	13,136
576.		57,033	14,258
577.		64,496	16,124
578.		57,569	14,392
579.		53,386	13,347
580.		42,977	10,744
581.		40,893	10,223
582.		37,133	9,283
583.		43,813	10,953
584.		40,937	10,234
585.		42,735	10,684
586.		42,371	10,593
587.		48,567	12,142
588.		43,081	10,770
589.		43,348	10,837
590.		44,852	11,213
591.		39,683	9,921
592.		44,614	11,154
593.		40,732	10,183
594.		40,086	10,022

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
595.		51,089	12,772
596.		44,218	11,055
597.		44,005	11,001
598.		51,114	12,779
599.		44,005	11,001
600.		44,072	11,018
601.		47,326	11,832
602.		45,825	11,456
603.		44,594	11,149
604.		45,270	11,318
605.		59,055	14,764
606.		52,916	13,229
607.		49,117	12,279
608.		34,568	8,642
609.		42,191	10,548
610.		57,331	14,333
611.		35,220	8,805
612.		34,357	8,589
613.		42,091	10,523
614.		39,922	9,981
615.		40,294	10,074
616.		37,159	9,290
617.		40,018	10,005
618.		31,100	7,775
619.		35,317	8,829
620.		38,307	9,577
621.		37,233	9,308
622.		49,234	12,309
623.		38,520	9,630
624.		32,804	8,201
625.		36,994	9,249
626.		38,031	9,508
627.		41,301	10,325
628.		25,571	6,393
629.		25,179	6,295
630.		31,990	7,998
631.		30,204	7,551
632.		25,817	6,454
633.		26,719	6,680
634.		23,756	5,939
635.		39,807	9,952
636.		37,971	9,493
637.		19,608	4,902
638.		29,949	7,487
639.		24,796	6,199
640.		26,439	6,610
641.		26,767	6,692
642.		27,541	6,885
643.		17,788	4,447
644.		45,836	11,459
645.		30,144	7,536
646.		31,909	7,977
647.		31,896	7,974
648.		49,311	12,328

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
649.		39,010	9,753
650.		36,206	9,052
651.		31,814	7,954
652.		35,133	8,783
653.		37,082	9,271
654.		30,192	7,548
655.		31,156	7,789
656.		31,263	7,816
657.		33,287	8,322
658.		36,505	9,126
659.		37,657	9,414
660.		30,965	7,741
661.		34,011	8,503
662.		35,013	8,753
663.		32,704	8,176
664.		35,650	8,913
665.		7,300	1,825
666.		6,950	1,738
667.		35,428	8,857
668.		17,132	4,283
669.		4,889	1,222
670.		4,215	1,054
671.		4,554	1,139
672.		5,157	1,289
673.		4,980	1,245
674.		5,211	1,303
675.		34,609	8,652
676.		5,071	1,268
677.		4,421	1,105
678.		4,421	1,105
679.		5,250	1,313
680.		5,157	1,289
681.		4,571	1,143
682.		5,292	1,323
683.		56,054	14,014
684.		33,679	8,420
685.	79,924		27,973
686.	69,897		24,464
687.	60,352		21,123
688.		60,352	15,088
689.		69,897	17,474
690.		80,595	20,149
691.		80,595	20,149

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.

For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	683		683
2.	792		792
3.	792		792
4.	792		792
5.	792		792
6.	792		792
7.	792		792
8.	792		792
9.	792		792
10.	792		792
11.	792		792
12.	792		792
13.	792		792
14.	792		792
15.	792		792
16.	792		792
17.	984		984
18.	984		984
19.	1,557		1,557
20.	1,557		1,557
21.	1,557		1,557
22.	1,557		1,557
23.	1,557		1,557
24.	1,557		1,557
25.	1,557		1,557
26.	1,557		1,557
27.	1,557		1,557
28.	1,557		1,557
29.	546		546
30.	1,557		1,557
31.	1,557		1,557
32.	1,557		1,557
33.	1,557		1,557
34.	1,557		1,557
35.	1,557		1,557
36.	1,721		1,721
37.	2,404		2,404
38.	410		410
39.	2,404		2,404
40.	2,404		2,404
41.	2,240		2,240
42.	2,978		2,978
43.	3,388		3,388
44.	3,497		3,497
45.	3,497		3,497
46.	3,443		3,443
47.	3,497		3,497
48.	3,497		3,497
49.	3,497		3,497
50.	2,596		2,596
51.	3,497		3,497
52.	109		109
53.	1,749		1,749

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
54.	710		710
55.	4,044		4,044
56.	1,831		1,831
57.	4,044		4,044
58.	4,044		4,044
59.	4,044		4,044
60.	4,044		4,044
61.	4,044		4,044
62.	4,044		4,044
63.	4,044		4,044
64.	4,044		4,044
65.	4,044		4,044
66.	4,044		4,044
67.	4,044		4,044
68.	5,656		5,656
69.	6,421		6,421
70.	6,421		6,421
71.	6,421		6,421
72.	6,421		6,421
73.	2,459		2,459
74.	2,322		2,322
75.	7,869		7,869
76.	7,869		7,869
77.	7,869		7,869
78.	7,869		7,869
79.	7,869		7,869
80.	7,869		7,869
81.	8,525		8,525
82.	6,257		6,257
83.	4,563		4,563
84.	6,421		6,421
85.	7,022		7,022
86.	2,814		2,814
87.	7,951		7,951
88.	8,552		8,552
89.	6,995		6,995
90.	8,661		8,661
91.	9,426		9,426
92.	5,765		5,765
93.	4,235		4,235
94.	2,459		2,459
95.	10,000		10,000
96.	109		109
97.	5,055		5,055
98.	10,000		10,000
99.	8,251		8,251
100.	10,000		10,000
101.	10,000		10,000
102.	10,000		10,000
103.	10,000		10,000
104.	10,000		10,000
105.	10,000		10,000
106.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
107.	5,082		5,082
108.	246		246
109.	10,000		10,000
110.	10,000		10,000
111.	10,000		10,000
112.	10,000		10,000
113.	10,000		10,000
114.	10,000		10,000
115.	10,000		10,000
116.	10,000		10,000
117.	6,475		6,475
118.	10,000		10,000
119.	10,000		10,000
120.	10,000		10,000
121.	10,000		10,000
122.	10,000		10,000
123.	10,000		10,000
124.	10,000		10,000
125.	10,000		10,000
126.	10,000		10,000
127.	10,000		10,000
128.	7,650		7,650
129.	10,000		10,000
130.	10,000		10,000
131.	10,000		10,000
132.	10,000		10,000
133.	10,000		10,000
134.	10,000		10,000
135.	10,000		10,000
136.	10,000		10,000
137.	10,000		10,000
138.	10,000		10,000
139.	10,000		10,000
140.	10,000		10,000
141.	10,000		10,000
142.	10,000		10,000
143.	6,120		6,120
144.	10,000		10,000
145.	10,000		10,000
146.	10,000		10,000
147.	10,000		10,000
148.	10,000		10,000
149.	10,000		10,000
150.	10,000		10,000
151.	10,000		10,000
152.	10,000		10,000
153.	10,000		10,000
154.	10,000		10,000
155.	10,000		10,000
156.	10,000		10,000
157.	10,000		10,000
158.	10,000		10,000
159.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
160.	10,000		10,000
161.	10,000		10,000
162.	4,617		4,617
163.	8,525		8,525
164.	10,000		10,000
165.	10,000		10,000
166.	10,000		10,000
167.	10,000		10,000
168.	10,000		10,000
169.	10,000		10,000
170.	10,000		10,000
171.	10,000		10,000
172.	10,000		10,000
173.	10,000		10,000
174.	10,000		10,000
175.	10,000		10,000
176.	10,000		10,000
177.	10,000		10,000
178.	10,000		10,000
179.	10,000		10,000
180.	10,000		10,000
181.	492		492
182.	10,000		10,000
183.	10,000		10,000
184.	10,000		10,000
185.	10,000		10,000
186.	10,000		10,000
187.	10,000		10,000
188.	10,000		10,000
189.	10,000		10,000
190.	10,000		10,000
191.	10,000		10,000
192.	10,000		10,000
193.	10,000		10,000
194.	10,000		10,000
195.	10,000		10,000
196.	10,000		10,000
197.	8,388		8,388
198.	10,000		10,000
199.	10,000		10,000
200.	10,000		10,000
201.	8,169		8,169
202.	7,568		7,568
203.	10,000		10,000
204.	10,000		10,000
205.	10,000		10,000
206.	10,000		10,000
207.	10,000		10,000
208.	10,000		10,000
209.	355		355
210.	10,000		10,000
211.	10,000		10,000
212.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
213.	10,000		10,000
214.	10,000		10,000
215.	10,000		10,000
216.	6,995		6,995
217.	10,000		10,000
218.	10,000		10,000
219.	4,235		4,235
220.	10,000		10,000
221.	10,000		10,000
222.	10,000		10,000
223.	10,000		10,000
224.	10,000		10,000
225.	10,000		10,000
226.	1,093		1,093
227.	10,000		10,000
228.	10,000		10,000
229.	2,650		2,650
230.	10,000		10,000
231.	10,000		10,000
232.	10,000		10,000
233.	10,000		10,000
234.	10,000		10,000
235.	10,000		10,000
236.	10,000		10,000
237.	10,000		10,000
238.	10,000		10,000
239.	3,962		3,962
240.	5,082		5,082
241.	7,568		7,568
242.	4,399		4,399
243.	3,142		3,142
244.	4,262		4,262
245.	10,000		10,000
246.	10,000		10,000
247.	10,000		10,000
248.	10,000		10,000
249.	10,000		10,000
250.	10,000		10,000
251.	10,000		10,000
252.	10,000		10,000
253.	10,000		10,000
254.	10,000		10,000
255.	10,000		10,000
256.	10,000		10,000
257.	10,000		10,000
258.	10,000		10,000
259.	10,000		10,000
260.	10,000		10,000
261.	10,000		10,000
262.	10,000		10,000
263.	10,000		10,000
264.	10,000		10,000
265.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
266.	10,000		10,000
267.	10,000		10,000
268.	10,000		10,000
269.	10,000		10,000
270.	10,000		10,000
271.	10,000		10,000
272.	10,000		10,000
273.	10,000		10,000
274.	10,000		10,000
275.	10,000		10,000
276.	10,000		10,000
277.	7,514		7,514
278.	10,000		10,000
279.	10,000		10,000
280.	10,000		10,000
281.	10,000		10,000
282.	10,000		10,000
283.	10,000		10,000
284.	10,000		10,000
285.	10,000		10,000
286.	10,000		10,000
287.	10,000		10,000
288.	10,000		10,000
289.	10,000		10,000
290.	10,000		10,000
291.	10,000		10,000
292.	10,000		10,000
293.	10,000		10,000
294.	10,000		10,000
295.	10,000		10,000
296.	10,000		10,000
297.	10,000		10,000
298.	10,000		10,000
299.	7,049		7,049
300.	10,000		10,000
301.	10,000		10,000
302.	10,000		10,000
303.	2,760		2,760
304.	10,000		10,000
305.	10,000		10,000
306.	10,000		10,000
307.	10,000		10,000
308.	10,000		10,000
309.	10,000		10,000
310.	10,000		10,000
311.	10,000		10,000
312.	10,000		10,000
313.	10,000		10,000
314.	10,000		10,000
315.	10,000		10,000
316.	10,000		10,000
317.	10,000		10,000
318.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
319.	10,000		10,000
320.	5,328		5,328
321.	10,000		10,000
322.	10,000		10,000
323.	10,000		10,000
324.	10,000		10,000
325.	10,000		10,000
326.	10,000		10,000
327.	10,000		10,000
328.	10,000		10,000
329.	10,000		10,000
330.	10,000		10,000
331.	10,000		10,000
332.	10,000		10,000
333.	10,000		10,000
334.	10,000		10,000
335.	10,000		10,000
336.	10,000		10,000
337.	10,000		10,000
338.	10,000		10,000
339.	8,224		8,224
340.	10,000		10,000
341.	10,000		10,000
342.	10,000		10,000
343.	10,000		10,000
344.	10,000		10,000
345.	10,000		10,000
346.	10,000		10,000
347.	10,000		10,000
348.	10,000		10,000
349.	10,000		10,000
350.	10,000		10,000
351.	10,000		10,000
352.	10,000		10,000
353.	10,000		10,000
354.	10,000		10,000
355.	10,000		10,000
356.	10,000		10,000
357.	437		437
358.	10,000		10,000
359.	10,000		10,000
360.	10,000		10,000
361.	10,000		10,000
362.	10,000		10,000
363.	10,000		10,000
364.	10,000		10,000
365.	10,000		10,000
366.	10,000		10,000
367.	10,000		10,000
368.	10,000		10,000
369.	10,000		10,000
370.	10,000		10,000
371.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
372.	10,000		10,000
373.	10,000		10,000
374.	10,000		10,000
375.	10,000		10,000
376.	10,000		10,000
377.	10,000		10,000
378.	10,000		10,000
379.	10,000		10,000
380.	10,000		10,000
381.	10,000		10,000
382.	10,000		10,000
383.	10,000		10,000
384.	10,000		10,000
385.	10,000		10,000
386.	10,000		10,000
387.	1,366		1,366
388.	10,000		10,000
389.	5,902		5,902
390.	10,000		10,000
391.	10,000		10,000
392.	10,000		10,000
393.	10,000		10,000
394.	10,000		10,000
395.	10,000		10,000
396.	10,000		10,000
397.	10,000		10,000
398.	9,727		9,727
399.	10,000		10,000
400.	10,000		10,000
401.	10,000		10,000
402.	9,738		9,738
403.	10,000		10,000
404.	10,000		10,000
405.	10,000		10,000
406.	10,000		10,000
407.	10,000		10,000
408.	10,000		10,000
409.	10,000		10,000
410.	10,000		10,000
411.	10,000		10,000
412.	10,000		10,000
413.	10,000		10,000
414.	10,000		10,000
415.	10,000		10,000
416.	10,000		10,000
417.	10,000		10,000
418.	10,000		10,000
419.	10,000		10,000
420.	10,000		10,000
421.	10,000		10,000
422.	10,000		10,000
423.	10,000		10,000
424.	10,000		10,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
425.	1,831		1,831
426.	10,000		10,000
427.	10,000		10,000
428.	10,000		10,000
429.	10,000		10,000
430.	10,000		10,000
431.	10,000		10,000
432.	10,000		10,000
433.	10,000		10,000
434.	10,000		10,000
435.	10,000		10,000
436.	10,000		10,000
437.	10,000		10,000
438.	10,000		10,000
439.	10,000		10,000
440.	10,000		10,000
441.	10,000		10,000
442.	10,000		10,000
443.	10,000		10,000
444.	10,000		10,000
445.	10,000		10,000
446.	10,000		10,000
447.	10,000		10,000
448.	732		732
449.	10,000		10,000
450.	10,000		10,000
451.	10,000		10,000
452.	8,005		8,005
453.	10,000		10,000
454.	10,000		10,000
455.	10,000		10,000
456.	10,000		10,000
457.	10,000		10,000
458.	10,000		10,000
459.	10,000		10,000
460.	10,000		10,000
461.	10,000		10,000
462.	10,000		10,000
463.	10,000		10,000
464.	10,000		10,000
465.	6,694		6,694
466.	5,000		5,000
467.	5,000		5,000
468.	5,000		5,000
469.	5,000		5,000
470.	5,000		5,000
471.	5,000		5,000
472.	5,000		5,000
473.	5,000		5,000
474.	5,000		5,000
475.	5,000		5,000
476.	5,000		5,000
477.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
478.	5,000		5,000
479.	5,000		5,000
480.	5,000		5,000
481.	5,000		5,000
482.	5,000		5,000
483.	5,000		5,000
484.	5,000		5,000
485.	5,000		5,000
486.	5,000		5,000
487.	5,000		5,000
488.	3,074		3,074
489.	5,000		5,000
490.	5,000		5,000
491.	5,000		5,000
492.	5,000		5,000
493.	5,000		5,000
494.	5,000		5,000
495.	5,000		5,000
496.	5,000		5,000
497.	5,000		5,000
498.	5,000		5,000
499.	5,000		5,000
500.	5,000		5,000
501.	5,000		5,000
502.	5,000		5,000
503.	5,000		5,000
504.	5,000		5,000
505.	5,000		5,000
506.	5,000		5,000
507.	5,000		5,000
508.	5,000		5,000
509.	5,000		5,000
510.	5,000		5,000
511.	5,000		5,000
512.	5,000		5,000
513.	5,000		5,000
514.	5,000		5,000
515.	5,000		5,000
516.	5,000		5,000
517.	5,000		5,000
518.	5,000		5,000
519.	5,000		5,000
520.	5,000		5,000
521.	5,000		5,000
522.	5,000		5,000
523.	5,000		5,000
524.	5,000		5,000
525.	5,000		5,000
526.	5,000		5,000
527.	5,000		5,000
528.	5,000		5,000
529.	5,000		5,000
530.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
531.	273		273
532.	3,962		3,962
533.	3,962		3,962
534.	4,768		4,768
535.	4,768		4,768
536.	4,768		4,768
537.	4,768		4,768
538.	5,000		5,000
539.	5,000		5,000
540.	5,000		5,000
541.	4,672		4,672
542.	5,000		5,000
543.	4,672		4,672
544.	4,672		4,672
545.	4,672		4,672
546.	4,672		4,672
547.	4,672		4,672
548.	4,672		4,672
549.	4,672		4,672
550.	4,672		4,672
551.	4,672		4,672
552.	4,672		4,672
553.	4,672		4,672
554.	4,672		4,672
555.	4,672		4,672
556.	3,962		3,962
557.	5,000		5,000
558.	5,000		5,000
559.	4,194		4,194
560.	5,000		5,000
561.	5,000		5,000
562.	4,194		4,194
563.	4,194		4,194
564.	5,000		5,000
565.	4,290		4,290
566.	4,290		4,290
567.	4,290		4,290
568.	4,290		4,290
569.	4,290		4,290
570.	5,000		5,000
571.	4,290		4,290
572.	4,290		4,290
573.	4,290		4,290
574.	4,290		4,290
575.	4,290		4,290
576.	5,000		5,000
577.	4,290		4,290
578.	4,290		4,290
579.	4,290		4,290
580.	3,716		3,716
581.	3,716		3,716
582.	3,716		3,716
583.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
584.	3,716		3,716
585.	3,716		3,716
586.	3,716		3,716
587.	3,716		3,716
588.	3,716		3,716
589.	3,716		3,716
590.	3,716		3,716
591.	3,716		3,716
592.	3,716		3,716
593.	3,716		3,716
594.	3,716		3,716
595.	4,194		4,194
596.	4,194		4,194
597.	4,194		4,194
598.	4,194		4,194
599.	4,194		4,194
600.	4,194		4,194
601.	4,194		4,194
602.	4,194		4,194
603.	4,194		4,194
604.	4,194		4,194
605.	4,194		4,194
606.	3,962		3,962
607.	3,962		3,962
608.	3,429		3,429
609.	3,429		3,429
610.	5,000		5,000
611.	3,429		3,429
612.	3,429		3,429
613.	3,429		3,429
614.	3,429		3,429
615.	3,429		3,429
616.	3,429		3,429
617.	3,429		3,429
618.	3,429		3,429
619.	3,429		3,429
620.	5,000		5,000
621.	3,429		3,429
622.	3,429		3,429
623.	3,429		3,429
624.	3,579		3,579
625.	4,194		4,194
626.	4,194		4,194
627.	4,194		4,194
628.	2,951		2,951
629.	2,951		2,951
630.	2,951		2,951
631.	5,000		5,000
632.	2,951		2,951
633.	2,951		2,951
634.	2,951		2,951
635.	4,440		4,440
636.	2,951		2,951

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
637.	2,951		2,951
638.	2,951		2,951
639.	2,951		2,951
640.	2,951		2,951
641.	2,951		2,951
642.	2,951		2,951
643.	2,951		2,951
644.	2,951		2,951
645.	2,951		2,951
646.	2,951		2,951
647.	2,951		2,951
648.	2,951		2,951
649.	2,951		2,951
650.	2,951		2,951
651.	2,951		2,951
652.	5,000		5,000
653.	2,951		2,951
654.	2,951		2,951
655.	2,951		2,951
656.	2,951		2,951
657.	2,951		2,951
658.	2,951		2,951
659.	2,951		2,951
660.	2,951		2,951
661.	5,000		5,000
662.	2,951		2,951
663.	2,951		2,951
664.	2,951		2,951
665.	902		902
666.	902		902
667.	2,760		2,760
668.	1,708		1,708
669.	464		464
670.	464		464
671.	464		464
672.	464		464
673.	464		464
674.	464		464
675.	2,951		2,951
676.	464		464
677.	464		464
678.	464		464
679.	464		464
680.	464		464
681.	464		464
682.	464		464
683.	5,000		5,000
684.	2,760		2,760
685.	10,000		10,000
686.	10,000		10,000
687.	10,000		10,000
688.	5,000		5,000
689.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
690.	5,000		5,000
691.	5,000		5,000

Ontario apprenticeship training tax credit (total of amounts in column N) 500 4,744,816 O

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ P

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

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SCHEDULE 568

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information*.
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return*.
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x (days in the tax year 366 / 365) = ... ______ B

Qualified expenditure limit for the tax year (amount A or amount B, whichever applies) . . . . **210** 20,000,000 C

Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

	Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) 300	305	Expenditure limit allocated 310
1.	HYDRO ONE NETWORKS INC.	87086 5821 RC0001	20,000,000
2.	HYDRO ONE LIMITED	80512 9962 RC0001	
3.	HYDRO ONE INC.	86999 4731 RC0001	
4.	2486267 ONTARIO INC	80232 6124 RC0001	
5.	2486268 ONTARIO INC	80167 4078 RC0001	
6.	HYDRO ONE REMOTE COMMUNITIES INC.	87083 6269 RC0001	
7.	HYDRO ONE TELECOM INC.	86800 1066 RC0001	
8.	HYDRO ONE TELECOM LINK LIMITED	88786 7513 RC0001	
9.	MUNICIPAL BILLING SERVICES INC.	87560 6519 RC0001	
10.	HYDRO ONE LAKE ERIE LINK MANAGEMENT INC	87892 1519 RC0002	
11.	1938454 ONTARIO INC.	86391 7795 RC0002	
12.	1943404 ONTARIO INC.	86248 6123 RC0002	
13.	B2M GP INC.	81838 1840 RC0001	
14.	HYDRO ONE B2M HOLDINGS INC	82217 7531 RC0001	
15.	HYDRO ONE B2M LP INC.	81838 2046 RC0001	
16.	NORFOLK ENERGY INC	86289 0399 RC0001	
17.	NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	
18.	HALDIMAND COUNTY ENERGY INC	89076 2412 RC0001	
19.	HALDIMAND COUNTY HYDRO INC	89075 9814 RC0001	
20.	WOODSTOCK HYDRO SERVICES INC.	89909 5012 RC0001	
21.	1937672 ONTARIO INC.	81722 4561 RC0001	
22.	GREAT LAKES POWER TRANSMISSION HOLDINGS INC.	83008 2335 RC0001	
23.	GREAT LAKES POWER TRANSMISSION INC.	84500 6386 RC0001	
24.	GREAT LAKES POWER TRANSMISSION HOLDING CORP.	82511 0216 RC0001	
25.	1228185 ONTARIO INC.	88706 6090 RC0001	
26.	EAST WEST TIE INC.	80044 2113 RC0001	
27.	HYDRO ONE EAST-WEST TIE INC.	80105 5880 RC0001	
28.	1937680 ONTARIO INC.	81930 4924 RC0001	
29.	1937681 ONTARIO INC.	81722 4363 RC0001	
		Total expenditure limit (cannot exceed $20 million) 315	20,000,000 D

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year			400	3
Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**)	405	550,000 E		
Qualified expenditure limit for the tax year (amount C in Part 2)		20,000,000 F		
Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less)			410	550,000
Ontario business-research Institute tax credit (line 410 x 20 %)				110,000 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: [redacted]

105 Telephone number including area code: [redacted]

110 Name of the ERI on the contract: [redacted]

115 ERI code: 118

120 Date of contract (Year Month Day): 2016-07-28

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes [ ] 2 No [X]

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . . . . **130** ______ – ______

Is the claim filed for an OBRITC earned through a partnership?* . . . . . . **135** 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, are you a specified member? . . . . . . **140** 1 Yes [ ] 2 No [ ]

If the answer on line 135 is **yes**, what is the name of the partnership? . . . . . . **145** ______

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . . . . **150** ______ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1. Did the corporation enter into a contract with an ERI? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation? . . . . . **205** 1 Yes [X] 2 No [ ]
3. Was the corporation entitled to exploit the results of the SR&ED carried out under the contract? . . . . . **210** 1 Yes [X] 2 No [ ]

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4. Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment? . . . . . **215** 1 Yes [X] 2 No [ ]
5. Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI? . . . . . **220** 1 Yes [X] 2 No [ ]
6. Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages? . . . . . **225** 1 Yes [X] 2 No [ ]
7. Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation? . . . . . **230** 1 Yes [X] 2 No [ ]

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year **300** 300,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 300,000 x percentage on line 150 in Part 1 % = A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . **305** 366

Qualified expenditures for this contract for the tax year:

$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}}$ $\frac{109{,}800{,}000}{366}$ = ... **310** 300,000 B

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information
[redacted]

105 Telephone number including area code
[redacted]

110 Name of the ERI on the contract
[redacted]

115 ERI code 117

120 Date of contract (Year Month Day) 2015-12-31

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes [ ] 2 No [X]

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . **130** [ ] – [ ]

Is the claim filed for an OBRITC earned through a partnership?* . . . **135** 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, are you a specified member? . . . **140** 1 Yes [ ] 2 No [ ]

If the answer on line 135 is **yes**, what is the name of the partnership? . . . **145** ______

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . **150** ______ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1. Did the corporation enter into a contract with an ERI?	200	1 Yes X	2 No
2. Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation?	205	1 Yes X	2 No
3. Was the corporation entitled to exploit the results of the SR&ED carried out under the contract?	210	1 Yes X	2 No

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4. Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment?	215	1 Yes X	2 No
5. Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI?	220	1 Yes X	2 No
6. Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages?	225	1 Yes X	2 No
7. Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation?	230	1 Yes X	2 No

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year **300** 150,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 150,000 x percentage on line 150 in Part 1 % = ______ A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . **305** 366

Qualified expenditures for this contract for the tax year:

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{54{,}900{,}000}{366} = \quad \mathbf{310} \quad 150{,}000 \text{ B}$$

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 569

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT CONTRACT INFORMATION

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2016-12-31

- Use this schedule to support your claim for the Ontario business-research institute tax credit (OBRITC), which is made on Schedule 568, *Ontario Business-Research Institute Tax Credit*. Complete a separate Schedule 569 for each eligible contract.
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI). An ERI, for purposes of the OBRITC, is defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our web site. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The eligibility requirements in Part 2 of this schedule must be met for the qualifying corporation to claim an OBRITC for this contract.
- Eligible contracts entered into before August 10, 2007 were subject to advanced ruling legislation. OBRITC claims relating to one of these contracts must have the corresponding Ontario Ministry of Revenue ruling reference number entered at line 130 in Part 1 of this schedule.
- Corporations can only claim the OBRITC for the number of days in the tax year that the corporation **was not** connected to the ERI. Connected corporations, for the purposes of the OBRITC, are defined in subsection 97(4) of the *Taxation Act*, 2007 (Ontario).
- Eligible contracts and qualified expenditures are defined in subsections 97(6) and 97(8), respectively, of the *Taxation Act, 2007* (Ontario).
- According to subsections 97(16) and (19) of the *Taxation Act, 2007* (Ontario), qualified expenditures must be reduced by contributions the corporation received, is entitled to receive or may reasonably expect to receive. Qualified expenditures include repayment of government assistance made by the corporation during the year. Contribution and government assistance are defined in subsection 97(27) of the *Taxation Act, 2007* (Ontario).

Part 1 – Contract details

100 Name of person to contact for more information: [redacted]

105 Telephone number including area code: [redacted]

110 Name of the ERI on the contract: [redacted]

115 ERI code: 117

120 Date of contract (Year Month Day): 2016-10-12

If the date on line 120 is before August 10, 2007, was the contract subject to an advanced ruling? . . . **125** 1 Yes [ ] 2 No [X]

For all contracts entered into before August 10, 2007, enter the Ontario Ministry of Revenue ruling reference number . . . **130** ____ – ____

Is the claim filed for an OBRITC earned through a partnership?* . . . 1 Yes [ ] 2 No [X]

If the answer on line 135 is **yes**, are you a specified member? . . . 1 Yes [ ] 2 No [ ]

If the answer on line 135 is **yes**, what is the name of the partnership? . . . ____

Enter the corporation's percentage share of the income or loss of the partnership's fiscal period ending in the corporation's tax year . . . **150** ____ %

* When a corporate member of a partnership is claiming an amount for qualified expenditures incurred during the tax year under the eligible contract by the partnership, complete Schedule 569 as if the partnership were a corporation. Each corporate member, other than a specified member, should file a Schedule 569 as if it, instead of the partnership, had entered into the contract with the ERI and can claim the corporation's share of the partnership's qualified expenditures. Specified members of a partnership cannot claim an OBRITC. A definition of "specified member" can be found in subsection 248(1) of the federal *Income Tax Act*.

Part 2 – Eligibility

Contract:

1. Did the corporation enter into a contract with an ERI? . . . . . 200 1 Yes X 2 No ☐
2. Do the terms of the contract state that the ERI agrees to perform, in Ontario, scientific research and experimental development (SR&ED) related to the business carried on in Canada by the corporation? . . . . . 205 1 Yes X 2 No ☐
3. Was the corporation entitled to exploit the results of the SR&ED carried out under the contract? . . . . . 210 1 Yes X 2 No ☐

If you answered **no** to question 1, 2, or 3, the contract is **not** an **eligible** contract for the purposes of an OBRITC.

Expenditures:

4. Were the expenditures made by a payment of money by the corporation to the ERI or by a prescribed payment? . . . . . 215 1 Yes X 2 No ☐
5. Were the expenditures incurred in respect of SR&ED carried on in Ontario by the ERI? . . . . . 220 1 Yes X 2 No ☐
6. Are the expenditures identified in subparagraph 37(1)(a)(i), (i.1) or (ii) of the federal *Income Tax Act* and would they also qualify as qualified expenditures, as defined in subsection 127(9) of the federal Act, other than prescribed types of expenditures and certain salaries or wages? . . . . . 225 1 Yes X 2 No ☐
7. Were the expenditures incurred by the corporation for purposes of SR&ED related to the business carried on in Canada by the corporation? . . . . . 230 1 Yes X 2 No ☐

If you answered **no** to question 4, 5, 6, or 7, the expenditures are **not eligible** expenditures for the purposes of an OBRITC.

Part 3 – Qualified expenditures for this contract for the tax year

Qualified expenditures incurred in the tax year 300 100,000

If the corporation answered **yes** at line 135 in Part 1, and **no** at line 140 in Part 1, determine the partnerships' share of qualified expenditures available to claim in the tax year:

Line 300 100,000 x percentage on line 150 in Part 1 % = ______ A

Number of days in this tax year that the corporation was **not** connected to the ERI identified on line 110 in Part 1 . . . . . 305 366

Qualified expenditures for this contract for the tax year:

$$\frac{\text{(Line 300 or amount A, whichever applies) x line 305}}{\text{number of days in the tax year}} \quad \frac{36,600,000}{366} = \ldots \quad 310 \quad 100,000 \text{ B}$$

Enter amount B on line 405 of **Schedule 568**, *Ontario Business-Research Institute Tax Credit*.

OEB Staff Interrogatory # 12

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-03
December 31, 2015 Tax Return, Schedule 4
Schedule 4 of the December 31, 2015 Tax Return indicates that Hydro One has significant non-capital loss carryforwards.

Interrogatory:

Please explain how these losses have been considered in the calculation of regulatory taxes for the test period.

Response:

Hydro One's non-capital loss carryforwards arose as a result of the additional tax deductions from the fair market value revaluation as a consequence of the IPO and the departure from the PILs regime.

These non-capital losses were not considered in the calculation of the regulatory taxes for the test period.

This was noted in Procedural Order No. 2 of this proceeding which stated:

> "The OEB understands that Hydro One's proposed treatment of tax savings resulting from the Government of Ontario's decision to sell its ownership interest in Hydro One Limited by way of an IPO and subsequent sale of shares in this Distribution Rates Application is consistent with its proposed approach to those savings in the Transmission application. That is, Hydro One does not intend to apply any tax savings resulting from the IPO to reduce Hydro One's distribution revenue requirement. As Hydro One notes "Neither the departure tax nor the change in tax regime will have any impact on ratepayers. For regulatory purposes, income tax expenses will continue to be calculated according to the method prescribed by the Board's 2006 EDR Tax Model and 2006 EDR Handbook, Section 7.1 "OEB 2006 Regulatory Taxes Expense Methodology"1. The OEB does not intend to have that

matter re-litigated in the current proceeding while the motion and appeal are pending. Accordingly, the OEB will not permit the Tax Savings Determination issue to be addressed in the distribution case, pending the outcomes of the Hydro One Motion and Appeal." (Decision on Issues List, Interim Rates and Procedural Order No. 2, December 1, 2017, page 3-4)

OEB Staff Interrogatory # 13

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-03
December 31, 2015 Tax Return, Schedule 10
Schedule 10 of the December 31, 2015 tax return indicates that Hydro One is eligible to receive a significant annual CEC deduction.

Interrogatory:

Although Hydro One does consider a CEC deduction in their calculation of the test period regulatory taxes, the deduction being allocated to the regulatory tax calculation is significantly less compared to what is available as per Schedule 10. Please explain why.

Response:

Hydro One's CEC balance mainly comprised of goodwill that was recognized from the fair market value revaluation of its assets when Hydro One exited the PILs regime as a consequence of the IPO and the goodwill that was purchased on LDC acquisitions. The CEC deduction on these portions of the goodwill was excluded from the regulatory tax calculations for reasons that are consistent with Exhibit I-03-Staff-12, and RP-2004-0188 Report of the Board for the purchased goodwill.

Arbourbrook Estates Interrogatory # 1

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

A-03-01

REF: Ontario Regulation 442/01 s. 1
Ontario Regulation 198/17 s. 2
Exhibit H1/Tab4/Schedule1/Attachment 4/pp. 5 to12.

Interrogatory:

a) Please provide updated bill impact schedules for the R1 and R2 Rate Classes (for all consumption levels included in the Application) that incorporate the impact of the Fair Hydro Plan on rates, including specifically the impact of Distribution Rate Protection (in conjunction with the already included RRRP).

Response:

a) The bill impacts for the R1 and R2 Rate Classes are included in the material provided in the response to Exhibit I-4-PWU-4.

Balsam Lake Coalition Interrogatory # 2

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

H1-04-01 Page 2

Interrogatory:

It appears to Balsam Lake that the filed bill impacts do not include the various impacts of the Fair Hydro Plan and related legislation on the proposed 2018 rates.

a) Please provide a version of Table 1: Distribution and Total Bill Impacts by Rate Class for Hydro One Customers that incorporates all the impacts of the Fair Hydro Plan; in doing so, please add a column that shows the 2017 DX Bill ($) that the column 2018 Change in DX Bill ($) is relative to, and a column that shows the 2017 Total Bill ($) that the 2017 Total Bill ($) is relative to.

Response:

a) Please see Attachment 1 to Exhibit I-4-PWU-4 for the revised version of Tables 1 and 2 of Exhibit H1, Tab 4, Schedule 1 that incorporates the impacts of the Fair Hydro Plan, and includes the 2017 Dx Bill ($).

Balsam Lake Coalition Interrogatory # 3

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

H1-01-01 Page 2
Ontario Regulation 442/01 s. 1
Ontario Regulation 198/17 s. 2

Interrogatory:

Ontario Regulation 442/01 s. 1 defines, in part, residential premises as "a dwelling occupied as a residence continuously for at least eight months of the year. . .".

Ontario Regulation 198/17 s. 2 provides Distribution Rate Protection to Hydro One's R1 and R2 customers so long as each such customer "resides continuously at the service address to which the account relates for at least eight months of the year".

Hydro One's Tariff of Rates and Charges asserts the following:

RESIDENTIAL SERVICE CLASSIFICATIONS

A year-round residential customer classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc. that for so long as he/she has year-round residential rate status for the identified dwelling, he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification.
2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.

4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential customer classification is defined as any residential service that does not meet residential year- round criteria. It includes dwellings such as cottages, chalets and camps.

The bill impacts experienced by Seasonal Customers relative to the UR, R1 and R2 classes results largely from the exclusion of customers designated as Seasonal Customers from Rural or Remote Electricity Rate Protection and Distribution Rate Protection.

a) Please confirm that Hydro One's Tariff of Rates and Charges as proposed in the proceeding distinguishes between "residential' and "seasonal" customers, in part, so as to distinguish between customers that qualify in accordance with Ontario Regulation 442/01 for Rural or Remote Electricity Rate Protection (RRRP) and customers that do not based on the criteria under that regulation that qualifying customers must occupy residential premises, which is defined as "a dwelling occupied as a residence continuously for at least eight months of the year. . .". If not confirmed, please explain why Hydro One distinguishes between "residential" and "seasonal" customers.

b) Please confirm that, with the introduction of Ontario Regulation 198/17, Hydro One's Tariff of Rates and Charges as proposed in the proceeding will serve to distinguish between "residential' and "seasonal" customers, in part, so as to distinguish between customers that qualify in accordance with Ontario Regulation 198/17 for Distribution Rate Protection (DRP) and customers that do not based on the criteria in the regulation that a qualifying customer must reside "continuously at the service address to which the account relates for at least eight months of the year". If not confirmed, please explain how Hydro One intends to distinguish between customers that qualify for DRP and those that do not.

c) Please confirm that when Hydro One refers in its Tariff to a year-round residential customer classification applying to a customer's "main place of abode", Hydro One's reference to a customer's "main place of abode" is intended to convey that in order to qualify as a "year-round residential customer" the customer must occupy residential premises, defined as a "dwelling occupied as a residence continuously for at least eight months of the year". If not confirmed please explain why Hydro One refers to a customer's main place of abode?
d) Does Hydro One agree that a customer could occupy two (or more) residences continuously for at least eight months of the year? If not why not?

e) Does Hydro One agree that a customer can occupy a residence continuously for at least eight months of the year without living at the residence 4 days of the week for 8 months of the year? If not why not?

f) Does Hydro One agree that a customer can occupy a residence continuously for at least eight months of the year without the address of the residence appearing on documents such as the occupant's electric bill, driver's licence, credit card invoices, property tax bill, etc.? If not why not?

g) Does Hydro One agree that a customer can occupy a residence continuously for at least eight months of the year without being enumerated for the purpose of voting in Provincial or Federal elections at the address of that residence? If not why not?

h) What independent dispute process does Hydro One have in place for customers wishing to dispute their Seasonal Class designation?

i) What steps does Hydro One take, if any, to confirm the "year round" status of its customers on an ongoing basis?

Response:

a) Confirmed.

b) Regulation 198/17 applies specifically to customers in the R1 and R2 year-round residential classes, and the criteria in the regulation that a qualifying customer must reside "continuously at the service address to which the account relates for at least eight months of the year" was specifically added to the regulation so as to exclude seasonal residential customers from getting the DRP should seasonal customers be included in the R1 or R2 rate classes at some point in the future.

c) The intent is in part to satisfy the requirement that the dwelling is occupied as a residence continuously for at least eight months of the year, but it is also linked to the first criteria which requires that a customer will not designate another property as a year-round residence for purposes of Hydro One rate classification.

d) Hydro One does not agree. Hydro One interprets the requirement to “reside continuously for at least eight months of the year” as referring to a customer’s year-round residential classification, and as stated in the first criteria above, for purposes of Hydro One’s rate classification a customer cannot designate another property as a year-round residence.

e) Hydro One expects that a customer with a year-round residential property would typically reside at that property for at least 4 days of the week for 8 months of the year, but there may be unusual situations during which a customer may not be using their year-round residential property in this manner.

f) Hydro One expects that a customer with a year-round residential property would typically show the address of that property on the documents referenced in the question.

g) Hydro One expects that a customer with a year-round residential property would typically show the address of that property for the purpose of voting in Provincial or Federal elections.

h) Hydro One aims to resolve any customer concern the first time a customer contacts Hydro One. Hydro One has a three step dispute resolution process. Additionally a customer has the opportunity to contact either, or both, the independent Hydro One Ombudsman or the Regulator (Ontario Energy Board) if a customer is dissatisfied with the resolution outcome.

i) Year round status of residential customers is confirmed upon new service connection or upgrade, at time of customer move into a property and at time of a customer notification of change to their service or account.

Building Owners and Managers Association Toronto Interrogatory # 17

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

A-03-01

Interrogatory:

a) p2 - Please provide the forecast percentage rate increase for each year over the period 2018 to 2022, commencing with the 2018 rates over existing 2017 rates.

   i. Please provide the derivation underlying calculations of the 4.7% as the 3.0% of the cited at lines 19 and 20.
   ii. Please provide the same data as in (i) for historical years 2017 over 2016, 2016 over 2015, 2015 over 2014, 2014 over 2013, and 2013 over 2012.

b) p23 - What are 2016 Actual Revenue Requirement relative to Board-approved Revenue Requirement?

c) What are the 2017 actual OM&A to date (September 30, 2017)? Extend revenue to date?

d) p5 – Please provide the derivation of the 4.2% reduction in capital expenditures from 2017 Board-approved levels. What is the year to date and current forecast 2017 actual capital expenditures?

e) Please confirm that for residential customers in 2018, the distribution rate is determined to the extent of 75% by customer charge, which does not vary with electricity consumption on demand.

f) Please show the corresponding bill increases for section **Error! Reference source not ound.** above

Response:

a) The forecast percentage rate increase of 4.9% shown in the reference A-03-01 was subsequently updated to 6.1% as shown on page 3 of Exhibit Q-01-01 filed with the Board on December, 21, 2017. The answers below are provided based on Hydro One's current proposal as per Exhibit Q-01-01.

The forecast percentage rate increases are provided in the table below as requested.

2018 increase over 2017	**2019 increase over 2018**	**2020 increase over 2019**	**2021 increase over 2020**	**2022 increase over 2021**
6.1%	3.6%	2.9%	2.4%	2.2%

i. The Derivation of 6.1% is the combined impact of a 3.1% increase in 2018 revenue requirement plus riders and other revenues over the equivalent amounts in 2017, plus a 3.0% increase due to the revenue deficiency associated with rebasing the load forecast in 2018. The calculations are shown in the table below. Details of the revenue deficiency associated with the load forecast impact of 3.0% is provided in the response to Exhibit I-19-BOMA-19 part h).

	2017	**2018**
Revenue Requirement	1,467.6	1,517.1
Rate Riders	11.1	6.2
Other revenue impacts	(52.7)	(53.6)
Rates Revenue Requirement	**1,426.0**	**1,469.7**
Rates Increase over 2017		3.1%
Load Impact		3.0%
Rate Increase Required		6.1%

ii. Please see the table below for the information requested.

	2013 over 2012	**2014 over 2013**	**2015 over 2014**	**2016 over 2015**	**2017 over 2016**
Change in Revenue	1.1%	3.5%	11.2%	6.3%	0.4%
Load Impact	0% *	0% *	0.7%	-0.5%	-0.8%
Total	**1.1%**	**3.5%**	**11.9%**	**5.8%**	**-0.4%**

* IRM years – no changes to load forecast.

b) Please refer to the following exhibits where actuals have been filed. For 2016 actual OM&A, please refer to Exhibit C1, Tab 1, Schedule 1. For actual depreciation expense, please refer to C1, Tab 6, Schedule 1. For actual calculation of utility income taxes, please refer to Exhibit C1, Tab 7, Schedule 2, Attachment 3. For actual external revenues, please refer to Exhibit E1, Tab 1, Schedule 2.

c) While this interrogatory requests "the actual OM&A to date (September 30, 2017), Hydro One proposes to provide year end actual 2017 OM&A when available, consistent with other requests.

d) The 4.2% reduction in capital expenditures is captured in the 2017 Bridge Variance column of Exhibit A-03-01 (Table 9). 2017 actuals will be made available at a later date.

e) No that is not correct. As shown in the evidence at Exhibit H1, Tab 1, Schedule 2, page 1, the fixed customer charges collected from the residential classes in 2018 account for 83% of UR class revenue, 65% of the R1 class revenue, 68% of the R2 class revenue, and 66% of the Seasonal class revenue.

f) The bill increases for each rate class corresponding with the proposed revenue requirement and load forecast for all years of this application are provided in Table 1 of Exhibit H1, Tab 4, Schedule 1 of the evidence.

Building Owners and Managers Association Toronto Interrogatory # 30

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

A-03-01 Page: 36

Interrogatory:

Big increase in bill (10%) for DG customer. Please provide an additional column showing the Rate Impact for each customer class.

Response:

The impact of the proposed rates on distribution portion of the bill are shown in the table provided in Exhibit H1, Tab 4, Schedule 1, Attachment 1, page 1.

Building Owners and Managers Association Toronto Interrogatory # 124

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

Exhibit B, Tab 1, Schedule 1; DSP 2.6 Page 9 Table 31

Interrogatory:

a) Please calculate the average of the actual increase from 2012 to 2017 and the average forecast annual price increase from 2018 to 2022.

b) Please provide the rationale for the near doubling of the forecast rates from the actual rates for the last five years.

c) Please provide copies of some documents for the above data. Why does it exceed the CPI to such a large extent, prices forecast from the forecast global usage?

d) What does the impact of a one percent increase in the CDN$/US$ (increase in strength of the CDN $) have on HONI's capital and OM&A budget?

Response:

a) The average increases are provided in the following table.

Average Increase of Escalators (%)

	2012-2017	2018-2022
Distribution Cost Escalation for Construction	2.2	2.88
Distribution Cost Escalation for Operations & Maintenance	0.65	2.22

b) The escalators include various material and labour costs relevant to the distribution business. The actual and forecast of escalators were provided by IHS Global Insight. However, the figures are consistent with decline in commodity prices and slow wage growth between 2012 and 2017 and expected improvement in this regard over the forecast period.

c) Components of distribution cost escalators are different from those in CPI. The escalators include various material and labour costs relevant to distribution system, while CPI includes cost of various consumer goods. Consequently, distribution cost escalators are not comparable with CPI. The forecast was provided by IHS Global Insight using an international model, and Hydro One does not have documentation for the model.

d) In 2016, Hydro One had approximately $53.4 million of purchases in US$ currency. Based on that, a one percent increase in the strength of the Canadian dollar would have a $0.5 million impact ($53.4M * 1%).

Canadian Manufacturers & Exporters Interrogatory # 96

Issue:
Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:
H1-03-01

Interrogatory:
a) Are the rate riders for any of the rate classes calculated in Table 2 impacted by the Distribution Rate Protection program and/or the First Nations On-Reserve Delivery Credit as set out in the Fair Hydro Act? Please explain fully.

Response:
a) The rate riders calculated in Table 2 are not impacted by the Distribution Rate Protection program or the First Nations On-Reserve Delivery Credit as set out in the Fair Hydro Act.

The Distribution Rate Protection only provides a subsidy to the base distribution rates, which is defined in the regulation as specifically excluding any fixed or variable rate riders or adders.

The First Nations Delivery Credit ("FNDC") provides on-reserve First Nations customers a credit that is equivalent to the delivery charge, which includes rate riders. However, the rate rider calculations are not affected by the FNDC, as Hydro One will recover the rate rider amounts from the Ontario government instead of the customer.

Canadian Manufacturers & Exporters Interrogatory # 97

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

H1-03-01
H1-04-

Interrogatory:

a) Please provide a version of Table 1 (Tab 4) that shows the distribution and total bill impacts by rate class if the rate riders calculated in Table 3 (Tab 3) were calculated based on a disposition period of 1 year instead of 5 years as proposed by Hydro One.

Response:

a) Table 1 below provides a calculation of the regulatory assets rate rider by class based on a disposition period of 1 year. The bill impacts by rate class in Exhibit H1-04-01, updated to reflect a one-year disposition, are provided in Attachment 1 of this response.

Table 1 - 2018 Regulatory Assets Rate Rider by Rate Class based on 1 Year Disposition

Rate Class	2018		
	Fixed ($/month)	Variable ($/kWh or $/kW)	Variable ($/kWh or $/kW) Non WMP, Class B
UR	0.04	-0.00007	0.00021
R1	0.02	-0.00008	0.00021
R2	-0.10	-0.00013	0.00021
Seasonal	-0.01	-0.00014	0.00021
GSe	0.01	-0.00012	0.00021
GSd	-0.05	-0.03510	0.06089
UGe	0.04	-0.00007	0.00021
UGd	0.09	-0.02199	0.07792
St Lgt	0.04	-0.00023	0.00021
Sen Lgt	0.03	-0.00050	0.00021

<table>
<tr><th rowspan="2">Rate Class</th><th colspan="3">2018</th></tr>
<tr><th>Fixed ($/month)</th><th>Variable ($/kWh or $/kW)</th><th>Variable ($/kWh or $/kW) Non WMP, Class B</th></tr>
<tr><td>USL</td><td>0.01</td><td>-0.00010</td><td>0.00021</td></tr>
<tr><td>DGen</td><td>0.06</td><td>-0.00666</td><td>0.02075</td></tr>
<tr><td>ST-General</td><td rowspan="2">19.10</td><td>1.39111</td><td rowspan="2">0.05557</td></tr>
<tr><td>ST-Excl WMP</td><td>-2.13000</td></tr>
</table>

TABLE 2 - DISTRIBUTION AND TOTAL BILL IMPACTS BY RATE CLASS FOR HYDRO ONE CUSTOMERS UPDATED FOR RECOVERY OF ALL RATE RIDERS IN 2018

				2018				2019				2020				2021				2022			
Rate Class	**Consumption Level**	**Monthly Consumption (kWh)**	**Monthly Peak (kW)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**
UR	**Low**	350		$ 1.84	6.4%	$ 3.05	4.0%	$ 2.35	7.7%	$ 2.47	3.1%	$ 2.98	9.0%	$ 3.12	3.8%	$ 0.82	2.3%	$ 0.76	0.9%	$ 0.70	1.9%	$ 0.73	0.9%
	Typical	750		$ 1.38	4.3%	$ 3.83	2.9%	$ 1.05	3.1%	$ 1.11	0.8%	$ 1.10	3.2%	$ 1.15	0.8%	$ 0.82	2.3%	$ 0.64	0.5%	$ 0.70	1.9%	$ 0.74	0.5%
	Average	755		$ 1.37	4.2%	$ 3.84	2.9%	$ 1.04	3.1%	$ 1.09	0.8%	$ 1.07	3.1%	$ 1.13	0.8%	$ 0.82	2.3%	$ 0.64	0.5%	$ 0.70	1.9%	$ 0.74	0.5%
	High	1,400		$ 0.62	1.6%	$ 5.11	2.3%	$ (1.05)	-2.7%	$ (1.10)	-0.5%	$ (1.96)	-5.2%	$ (2.06)	-0.9%	$ 0.82	2.3%	$ 0.45	0.2%	$ 0.70	1.9%	$ 0.73	0.3%
R1	**Low**	400		$ 2.87	6.6%	$ 3.98	4.0%	$ 3.33	7.1%	$ 3.50	3.4%	$ 3.55	7.1%	$ 3.73	3.5%	$ 3.49	6.5%	$ 3.60	3.3%	$ 3.95	6.9%	$ 4.15	3.7%
	Typical	750		$ 2.57	5.0%	$ 4.51	3.0%	$ 2.41	4.4%	$ 2.53	1.6%	$ 2.40	4.2%	$ 2.51	1.6%	$ 1.95	3.3%	$ 1.93	1.2%	$ 2.20	3.6%	$ 2.31	1.4%
	Average	920		$ 2.42	4.4%	$ 4.76	2.7%	$ 1.96	3.4%	$ 2.06	1.1%	$ 1.83	3.1%	$ 1.93	1.0%	$ 1.20	1.9%	$ 1.12	0.6%	$ 1.35	2.1%	$ 1.42	0.8%
	High	1,800		$ 1.65	2.2%	$ 6.09	1.9%	$ (0.35)	-0.5%	$ (0.37)	-0.1%	$ (1.07)	-1.4%	$ (1.12)	-0.4%	$ (2.67)	-3.5%	$ (3.09)	-1.0%	$ (3.05)	-4.2%	$ (3.20)	-1.0%
R2	**Low**	450		$ 3.09	8.1%	$ 4.17	4.1%	$ 7.43	18.1%	$ 7.80	7.5%	$ 7.69	15.8%	$ 8.07	7.2%	$ 8.08	14.4%	$ 8.45	7.0%	$ 9.08	14.1%	$ 9.53	7.4%
	Typical	750		$ 2.66	5.4%	$ 4.33	2.9%	$ 6.26	12.1%	$ 6.58	4.2%	$ 6.13	10.5%	$ 6.44	4.0%	$ 6.04	9.4%	$ 6.28	3.7%	$ 6.56	9.3%	$ 6.89	3.9%
	Average	1,152		$ 2.09	3.3%	$ 4.56	2.1%	$ 4.70	7.1%	$ 4.94	2.2%	$ 4.04	5.7%	$ 4.24	1.8%	$ 3.31	4.4%	$ 3.38	1.4%	$ 3.18	4.1%	$ 3.34	1.4%
	High	2,300		$ 0.46	0.4%	$ 5.21	1.2%	$ 0.25	0.2%	$ 0.26	0.1%	$ (1.93)	-1.8%	$ (2.03)	-0.5%	$ (4.50)	-4.2%	$ (4.91)	-1.2%	$ (6.46)	-6.4%	$ (6.78)	-1.6%
Seasonal	**Low**	50		$ 3.21	8.0%	$ 3.44	6.9%	$ 4.19	9.6%	$ 4.40	8.2%	$ 4.54	9.5%	$ 4.76	8.2%	$ 4.71	9.0%	$ 4.95	7.9%	$ 5.45	9.6%	$ 5.72	8.5%
	Average	352		$ 2.11	3.5%	$ 2.70	2.5%	$ 1.96	3.2%	$ 2.06	1.8%	$ 1.85	2.9%	$ 1.94	1.7%	$ 1.03	1.6%	$ 1.09	0.9%	$ 1.43	2.1%	$ 1.50	1.3%
	High	1,000		$ (0.24)	-0.2%	$ 1.11	0.5%	$ (2.81)	-2.8%	$ (2.95)	-1.2%	$ (3.92)	-4.0%	$ (4.12)	-1.7%	$ (6.88)	-7.3%	$ (7.20)	-3.1%	$ (7.19)	-8.3%	$ (7.55)	-3.4%
GSe	**Low**	1,000		$ 3.76	4.4%	$ 4.48	2.0%	$ 2.94	3.3%	$ 3.09	1.3%	$ 2.68	2.9%	$ 2.81	1.2%	$ 2.40	2.5%	$ 2.33	1.0%	$ 2.36	2.4%	$ 2.48	1.0%
	Typical	2,000		$ 6.55	4.6%	$ 7.95	1.9%	$ 5.25	3.6%	$ 5.51	1.3%	$ 4.68	3.1%	$ 4.91	1.1%	$ 4.30	2.7%	$ 4.13	0.9%	$ 4.16	2.6%	$ 4.37	1.0%
	Average	1,982		$ 6.50	4.6%	$ 7.89	1.9%	$ 5.21	3.6%	$ 5.47	1.3%	$ 4.64	3.1%	$ 4.88	1.1%	$ 4.27	2.7%	$ 4.10	0.9%	$ 4.13	2.6%	$ 4.33	1.0%
	High	15,000		$ 42.82	4.9%	$ 53.02	1.8%	$ 35.28	3.9%	$ 37.05	1.2%	$ 30.68	3.2%	$ 32.21	1.1%	$ 29.00	3.0%	$ 27.57	0.9%	$ 27.56	2.7%	$ 28.94	0.9%
UGe	**Low**	1,000		$ 1.79	3.6%	$ 2.28	1.2%	$ 1.61	3.1%	$ 1.69	0.9%	$ 1.53	2.9%	$ 1.61	0.8%	$ 1.35	2.5%	$ 1.13	0.6%	$ 1.32	2.3%	$ 1.39	0.7%
	Typical	2,000		$ 3.63	4.8%	$ 4.61	1.3%	$ 2.67	3.3%	$ 2.81	0.8%	$ 2.43	2.9%	$ 2.55	0.7%	$ 2.25	2.7%	$ 1.78	0.5%	$ 2.12	2.4%	$ 2.23	0.6%
	Average	2,759		$ 5.02	5.2%	$ 6.38	1.3%	$ 3.48	3.4%	$ 3.65	0.8%	$ 3.11	3.0%	$ 3.27	0.7%	$ 2.93	2.7%	$ 2.28	0.5%	$ 2.73	2.5%	$ 2.86	0.6%
	High	15,000		$ 27.55	6.6%	$ 34.94	1.4%	$ 16.45	3.7%	$ 17.27	0.7%	$ 14.13	3.1%	$ 14.84	0.6%	$ 13.95	2.9%	$ 10.31	0.4%	$ 12.52	2.6%	$ 13.15	0.5%
GSd	**Low**	15,000	60	$ 71.24	6.9%	$ 87.70	2.7%	$ 37.28	3.4%	$ 42.12	1.3%	$ 34.68	3.0%	$ 39.19	1.2%	$ 31.89	2.7%	$ 31.55	0.9%	$ 30.38	2.5%	$ 34.33	1.0%
	Average	36,104	124	$ 140.24	6.9%	$ 173.36	2.4%	$ 75.21	3.4%	$ 84.99	1.2%	$ 69.54	3.1%	$ 78.58	1.1%	$ 66.44	2.8%	$ 65.51	0.9%	$ 62.98	2.6%	$ 71.17	0.9%
	High	175,000	500	$ 561.44	7.1%	$ 694.45	2.2%	$ 298.07	3.5%	$ 336.82	1.0%	$ 274.35	3.1%	$ 310.02	0.9%	$ 255.45	2.8%	$ 251.29	0.7%	$ 241.32	2.6%	$ 272.69	0.8%
UGd	**Low**	15,000	60	$ 54.60	8.7%	$ 91.04	3.3%	$ 19.99	2.9%	$ 22.59	0.8%	$ 21.10	3.0%	$ 23.84	0.8%	$ 19.69	2.7%	$ 17.35	0.6%	$ 18.42	2.5%	$ 20.81	0.7%
	Average	50,525	135	$ 133.69	10.5%	$ 217.08	2.7%	$ 42.59	3.0%	$ 48.13	0.6%	$ 44.60	3.1%	$ 50.39	0.6%	$ 43.13	2.8%	$ 37.46	0.4%	$ 39.99	2.5%	$ 45.19	0.5%
	High	175,000	500	$ 467.74	10.5%	$ 773.03	2.7%	$ 152.59	3.1%	$ 172.43	0.6%	$ 158.95	3.1%	$ 179.61	0.6%	$ 151.91	2.9%	$ 130.80	0.4%	$ 140.12	2.6%	$ 158.34	0.5%
St Lgt	**Low**	100		$ 0.22	1.6%	$ 0.44	1.6%	$ 0.45	3.2%	$ 0.47	1.7%	$ 0.45	3.1%	$ 0.47	1.7%	$ 0.70	4.7%	$ 0.56	2.0%	$ 0.39	2.5%	$ 0.41	1.4%
	Average	517		$ 2.09	4.0%	$ 3.26	2.7%	$ 1.91	3.5%	$ 2.01	1.6%	$ 1.78	3.2%	$ 1.87	1.5%	$ 1.78	3.1%	$ 0.97	0.8%	$ 1.56	2.4%	$ 1.64	1.3%
	High	2,000		$ 8.74	4.6%	$ 13.27	2.8%	$ 7.13	3.6%	$ 7.49	1.5%	$ 6.53	3.2%	$ 6.86	1.4%	$ 5.64	2.6%	$ 2.42	0.5%	$ 5.71	2.6%	$ 6.00	1.2%
Sen Lgt	**Low**	20		$ 0.44	8.6%	$ 0.50	6.1%	$ 0.36	6.4%	$ 0.38	4.3%	$ 0.35	5.8%	$ 0.36	4.0%	$ 0.21	3.3%	$ 0.18	1.9%	$ 0.26	4.1%	$ 0.28	2.9%
	Average	71		$ 0.49	4.3%	$ 0.66	3.1%	$ 0.79	6.8%	$ 0.83	3.8%	$ 0.72	5.8%	$ 0.75	3.4%	$ 0.36	2.7%	$ 0.25	1.1%	$ 0.55	4.1%	$ 0.58	2.5%
	High	200		$ 0.60	2.3%	$ 1.04	2.0%	$ 1.89	7.0%	$ 1.98	3.6%	$ 1.66	5.7%	$ 1.74	3.1%	$ 0.73	2.4%	$ 0.42	0.7%	$ 1.29	4.1%	$ 1.35	2.3%
USL	**Low**	100		$ (0.91)	-2.4%	$ (0.87)	-1.6%	$ 0.78	2.1%	$ 0.82	1.6%	$ 1.24	3.2%	$ 1.30	2.4%	$ 0.76	1.9%	$ 0.79	1.4%	$ 0.99	2.5%	$ 1.04	1.9%
	Average	364		$ (0.88)	-1.9%	$ (0.61)	-0.6%	$ 0.94	2.1%	$ 0.98	1.0%	$ 1.42	3.1%	$ 1.50	1.6%	$ 0.89	1.9%	$ 0.91	0.9%	$ 1.15	2.4%	$ 1.21	1.2%
	High	1,000		$ (0.81)	-1.3%	$ 0.03	0.0%	$ 1.31	2.1%	$ 1.38	0.7%	$ 1.87	2.9%	$ 1.96	1.0%	$ 1.21	1.8%	$ 1.20	0.6%	$ 1.53	2.3%	$ 1.61	0.8%
DGen	**Low**	300	10	$ 37.79	17.0%	$ 45.73	15.3%	$ 33.71	12.9%	$ 38.10	11.0%	$ 8.23	2.8%	$ 9.30	2.4%	$ 7.65	2.5%	$ 8.82	2.2%	$ 6.77	2.2%	$ 7.65	1.9%
	Average	1,328	13	$ 36.87	15.2%	$ 45.61	10.1%	$ 43.84	15.7%	$ 49.54	9.9%	$ 10.69	3.3%	$ 12.08	2.2%	$ 9.18	2.8%	$ 10.58	1.9%	$ 8.12	2.4%	$ 9.18	1.6%
	High	5,000	100	$ (17.40)	-2.0%	$ 10.66	0.6%	$ 337.64	40.2%	$ 381.53	22.4%	$ 82.26	7.0%	$ 92.95	4.5%	$ 76.52	6.1%	$ 88.19	4.1%	$ 67.68	5.0%	$ 76.48	3.4%
ST	**Low**	200,000	500	$ (288.74)	-15.9%	$ (224.57)	-0.8%	$ 375.12	24.5%	$ 423.88	1.4%	$ 55.86	2.9%	$ 63.13	0.2%	$ 32.44	1.7%	$ 92.76	0.3%	$ 50.62	2.5%	$ 57.20	0.2%
	Average	1,601,036	3,091	$ (1,148.30)	-26.7%	$ (668.82)	-0.3%	$ 2,289.63	72.5%	$ 2,587.29	1.2%	$ 179.74	3.3%	$ 203.10	0.1%	$ 121.02	2.2%	$ 468.85	0.2%	$ 152.76	2.7%	$ 172.62	0.1%
	High	4,000,000	10,000	$ (4,822.73)	-39.2%	$ (3,415.54)	-0.6%	$ 7,394.76	98.8%	$ 8,356.08	1.5%	$ 510.04	3.4%	$ 576.35	0.1%	$ 374.52	2.4%	$ 1,545.15	0.3%	$ 445.07	2.8%	$ 502.93	0.1%

Canadian Manufacturers & Exporters Interrogatory # 98

Issue:
Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:
None

Interrogatory:
a) Please provide any prospectuses or reports produced to shareholders or in connection with the sale of additional shares in the company.

Response:
Attached the prospectus relating to the IPO (Filed October 29, 2015), the Short Form Base Shelf Prospectus (Filed March 30, 2016) under which the secondary offerings subsequent to the IPO as well as the Short Form Prospectus (Filed August 1, 2017) used in conjunction with the offering of convertible debentures.

Readers are cautioned that there may be additional documents incorporated by reference to the Prospectus documents provided and such additional documents would be filed with the Ontario Securities Commission and available on SEDAR (www.sedar.com).

SUPPLEMENTED PREP PROSPECTUS

Initial Public Offering
by way of Secondary Offering

October 29, 2015

HYDRO ONE LIMITED

$1,662,550,000

81,100,000 Common Shares

This prospectus qualifies the distribution of 81,100,000 common shares of Hydro One Limited ("**common shares**") being offered by the Province of Ontario (the "**Province**" or the "**Selling Shareholder**") at a price of $20.50 per common share. **Hydro One Limited will not receive any proceeds from this offering**. See "Principal and Selling Shareholder".

Immediately following the closing of this offering, and the other transactions contemplated by this prospectus, the Province will hold approximately 85% of Hydro One Limited's total issued and outstanding common shares (approximately 84% if the Over-Allotment Option is exercised in full). As a result, the Province will have a significant influence over Hydro One Limited and its affairs. See "Governance and Relationship with Principal Shareholder" and "Risk Factors".

Prior to the closing of this offering, Hydro One Limited will acquire all of the issued and outstanding shares of Hydro One Inc. Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario by number of customers.

On August 31, 2015, at the direction of the Province, as sole shareholder of Hydro One Inc., Hydro One Inc. declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton Networks Inc. The dividend was paid to the Province, at its direction, by transferring all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning this dividend and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc.

There is currently no market through which Hydro One Limited's common shares may be sold, and purchasers may not be able to resell common shares purchased under this prospectus. This may affect the pricing of the common shares in the secondary market, the transparency and availability of trading prices, the liquidity of the common shares, and the extent of issuer regulation. See "Risk Factors". The Toronto Stock Exchange (the "**TSX**") has conditionally approved the listing of the common shares distributed under this prospectus on the TSX under the symbol "H". Listing will be subject to Hydro One Limited fulfilling all of the requirements of the TSX on or before January 25, 2016. See "Plan of Distribution".

Price: $20.50 per Common Share

	Price to the Public(1)	Underwriters' Fee(2)	Net Proceeds to the Selling Shareholder(3)
Per common share	$ 20.50	$0.205/$0.615	$ 20.172
Total offering(4)	$1,662,550,000	$ 26,600,800	$1,635,949,200

Notes:

(1) The offering price for the common shares will be determined by negotiations between the Province and the Underwriters (as defined below).

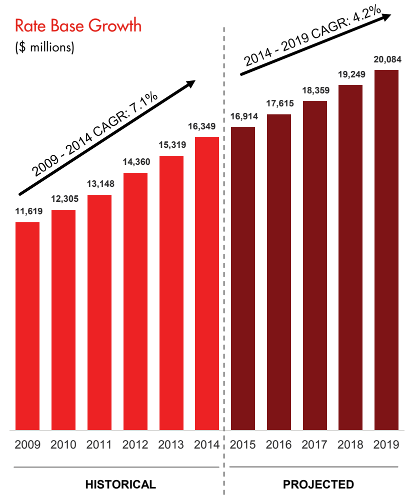
(continued on next page)

INVESTMENT HIGHLIGHTS

- ▶ Significant Scale and Leadership Position in Ontario
- ▶ Consistent and Stable, Rate-Regulated Environment
- ▶ Proven Senior Management Team and Experienced, Independent Board of Directors
- ▶ Stable Regulated Cash Flows and Strong Balance Sheet
- ▶ Robust and Predictable Organic Growth Profile

STABLE REGULATED CASH FLOWS AND STRONG BALANCE SHEET

- Essential rate-regulated infrastructure services generate 99% of revenues
- Stable, growing rate base underpins growth in net cash from operating activities and net income
  - Rate base growth of 7.1% (2009–2014 CAGR)
  - Net cash from operating activities growth of 7.1% (2009 – 2014 CAGR)
  - Net Income growth of 9.7% (2009 – 2014 CAGR)
- Active participant in public debt capital markets with strong "A" credit ratings



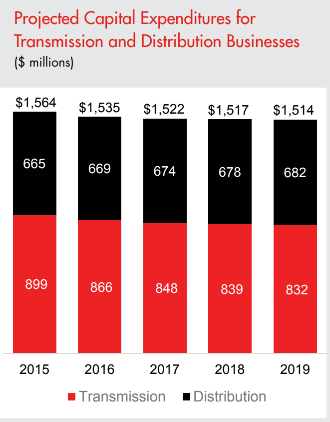
SIGNIFICANT SCALE AND LEADERSHIP POSITION IN ONTARIO

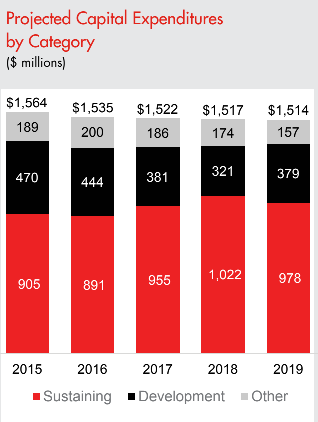
Key Advantages

- Low cost of borrowing and broad access to debt capital markets
- In-house team of industry experts
  - Asset management
  - Operations
  - Post-outage recovery
  - Project design
  - Engineering
  - Project management and construction
- Resources and commitment to invest in innovation, continuous improvement, customer service
- Comprehensive stakeholder engagement process
- Extensive experience building and maintaining effective relationships with First Nations and Métis communities
- Leading role in working with regulatory authorities on energy policy, regulatory changes, etc.

ROBUST AND PREDICTABLE ORGANIC GROWTH PROFILE

- Rate base growth represents greatest near term opportunity
- Estimated average annual capital investments of ~$1.5 billion per year over the next 5 years, with the focus on improving existing assets
- All capital expenditures are included in rate base
- Additional LDC consolidation opportunities





CONSISTENT AND STABLE, RATE-REGULATED ENVIRONMENT

- Stable and sophisticated regulator
- Transparent and predictable rate setting process
  - ROE set by a formula linked to long-term government bond yields and corporate bond spreads
- OEB-approved rates based on recovery of costs plus approved rate of return and incentive for productivity improvements
- Hydro One has earned or exceeded its allowed ROE on a consolidated basis

	2010	2011	2012	2013	2014	2015
Allowed ROE on Deemed Equity (40% of Capital Structure)						
Transmission	8.39%	9.66%	9.42%	8.93%	9.36%	9.30%
Distribution	9.85%	9.66%	9.66%	9.66%	9.66%	9.30%

(2) The Province has agreed to pay the Underwriters a fee of $0.205 for each common share sold to institutional investors and $0.615 for each common share sold to other investors (the "**Underwriters' Fee**"). The Underwriters' Fee shown in the table above and in note (4) below assumes that 70% of the Hydro One Limited common shares offered hereunder are sold to institutional investors. See "Plan of Distribution".

(3) After deducting the Underwriters' Fee shown in the table above but before deducting expenses of this offering, estimated to be $12,500,000, which will be paid by the Province. The Province has also agreed to reimburse the Underwriters for their reasonable expenses in connection with this offering.

(4) The Province has granted to the Underwriters an over-allotment option (the "**Over-Allotment Option**"), exercisable, in whole or in part, at any time for a period of 30 days after the closing date of this offering, to purchase from the Province up to an additional 8,150,000 common shares, on the same terms as set out above solely to cover over-allotments, if any. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Fee" and "Net Proceeds to the Selling Shareholder" will be $1,829,625,000, $29,274,000 and $1,800,351,000, respectively. This prospectus also qualifies the grant of the Over-Allotment Option and the distribution of up to 8,150,000 common shares sold by the Province if the Over-Allotment Option is exercised. A purchaser who acquires common shares forming part of the Underwriters' over-allocation position acquires those common shares under this prospectus, regardless of whether the Underwriters' over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. See "Plan of Distribution".

The following table sets out the number of common shares that may be sold by the Province to the Underwriters pursuant to the exercise of the Over-Allotment Option:

	Maximum Size or Number of Shares Available	Exercise Period	Exercise Price
Over-Allotment Option	8,150,000 common shares	For a period of 30 days after the closing date of this offering	$20.50 per common share

The underwriters for this offering are RBC Dominion Securities Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., TD Securities Inc., National Bank Financial Inc., Barclays Capital Canada Inc., Credit Suisse Securities (Canada), Inc., Goldman Sachs Canada Inc., Canaccord Genuity Corp., Desjardins Securities Inc., GMP Securities L.P., Raymond James Ltd., Dundee Securities Ltd., Industrial Alliance Securities Inc. and Manulife Securities Incorporated (collectively, the "**Underwriters**"). The Underwriters, as principals, conditionally offer the common shares, subject to prior sale, if, as and when sold by the Province and accepted by the Underwriters in accordance with the conditions contained in the underwriting agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of Hydro One Limited by Osler, Hoskin & Harcourt LLP, on behalf of the Province by Torys LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP.

In connection with this offering, the Underwriters may over-allot or effect transactions that stabilize or maintain the market price of the common shares at levels other than those which otherwise might prevail on the open market. **The Underwriters may offer the common shares at a lower price than stated above. See "Plan of Distribution".**

RBC Dominion Securities Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., TD Securities Inc., National Bank Financial Inc. and Desjardins Securities Inc. are subsidiaries or affiliates of lenders that have made certain existing credit facilities available to Hydro One Inc., which will become a wholly-owned subsidiary of Hydro One Limited prior to the closing of this offering and, in addition, are subsidiaries or affiliates of lenders that are anticipated to make certain new credit facilities available to both Hydro One Limited and Hydro One Inc. **Although Hydro One Limited is not offering common shares pursuant to this offering, it may be considered a connected issuer of the Underwriters who are affiliates of such lenders for purposes of securities laws in Canada.** See "Plan of Distribution" and "Pre-Closing Transactions".

Subscriptions will be received subject to rejection or allotment in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. Closing of this offering is expected to occur on or about November 5, 2015 or such later date as Hydro One Limited, the Selling Shareholder and the Underwriters may agree, but in any event not later than November 26, 2015 (the "**Closing Date**"). The common shares offered under this prospectus will be deposited with CDS Clearing and Depository Services Inc. in electronic form on the Closing Date. A purchaser of common shares pursuant to this offering will not receive a share certificate on closing.

An investment in Hydro One Limited's common shares is subject to a number of risks that should be considered by a prospective purchaser. Under securities laws in certain jurisdictions, the statutory remedies of rescission or damages where this prospectus contains a misrepresentation are not available against the Province, as selling shareholder or as a promoter of Hydro One Limited. The commencement of actions and enforcement of remedies against the Province may also be subject to limitations. The Province will not provide any guarantee in respect of the common shares. Prospective purchasers should carefully consider the risk factors described under "Risk Factors" before purchasing common shares.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process. See "Agent for Service of Process in Canada."

All of the information contained in the supplemented PREP prospectus that is not contained in this base PREP prospectus will be incorporated by reference into this base PREP prospectus as of the date of the supplemented PREP prospectus.

Hydro One Limited's registered office and head office is located at 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5.

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MEANING OF CERTAIN REFERENCES

Capitalized terms used in this prospectus are defined under "Glossary". Words importing the singular number include the plural, and vice versa, and words importing any gender include all genders.

Unless otherwise noted or the context otherwise requires, references to "**Hydro One**" or the "**Company**" refer to Hydro One Limited, Hydro One Inc. and their subsidiaries taken together as a whole as they will exist immediately following the closing of this offering and the related pre-closing steps described under "Pre-Closing Transactions". References to "**Hydro One Inc.**" refer only to Hydro One Inc. and references to "**Hydro One Limited**" refer only to Hydro One Limited.

In addition, "**Province**" refers to the Province of Ontario as a provincial government entity, and "**Ontario**" or the "**province**" in lower case type refers to the Province of Ontario as a geographical area.

References to "**management**" in this prospectus mean the persons who are identified in this prospectus as executive officers of Hydro One Limited and who will be the executive officers of Hydro One Limited and its operating subsidiaries, as the case may be, following the closing of this offering. Any statements in this prospectus made by or on behalf of management are made in such persons' respective capacities as executive officers of Hydro One Limited and its operating subsidiaries, as applicable, and not in their personal capacities. See "Directors and Management of the Company".

This prospectus refers to certain terms commonly used in the electricity industry, such as "**rate-regulated**", "**rate base**" and "**return on equity**". For a description of these terms, see "Rate-Regulated Utilities". The terms rate base and return on equity are not considered non-GAAP measures. Rate base is an amount that a utility is required to calculate for regulatory purposes, and refers to the net book value of the utility's assets for regulatory purposes. Return on equity is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base. Hydro One refers to the rate base and return on equity of its transmission and distribution businesses because it believes that such terms assist in understanding Hydro One's business and are commonly used by investors and research analysts to help evaluate the performance of rate-regulated utilities.

In this prospectus, all dollar amounts are expressed in Canadian dollars unless otherwise indicated. All references to "**$**" or "**dollars**" are to Canadian dollars, and all references to "**U.S.$**" are to U.S. dollars.

ABOUT THIS PROSPECTUS

A prospective purchaser should rely only on the information contained in this prospectus and is not entitled to rely on parts of the information contained or incorporated by reference in this prospectus to the exclusion of others. Hydro One, the Selling Shareholder and the Underwriters have not authorized anyone to provide prospective purchasers with additional or different information. The Selling Shareholder and the Underwriters are not offering to sell the common shares in any jurisdiction where the offer or sale of such securities is not permitted. The information contained in this prospectus is accurate only as of the date of this prospectus or the date indicated, regardless of the time of delivery of this prospectus or of any sale of the common shares.

Unless otherwise indicated or the context otherwise requires, the disclosure contained in this prospectus assumes that: (i) the Over-Allotment Option has not been exercised; and (ii) the transactions referred to under the heading "Pre-Closing Transactions" have been completed, following which Hydro One Inc. will be a wholly-owned subsidiary of Hydro One Limited. See "Pre-Closing Transactions".

On August 31, 2015, at the direction of the Province, as sole shareholder of Hydro One Inc., Hydro One Inc. declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton Networks Inc. The dividend was paid to the Province, at its direction, by transferring all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning this dividend and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc.

Because this dividend occurred after the dates of, and periods covered by, the consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the consolidated financial information derived from those financial statements include the assets, liabilities and results of operations of Hydro One Brampton Networks Inc.

To see the impact of certain transactions related to this offering on the financial statements of Hydro One Inc., including the transfer of all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province, see the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, together with "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information".

For prospective purchasers outside Canada, none of Hydro One, the Selling Shareholder or any of the Underwriters has done anything that would permit this offering or possession or distribution of this prospectus in any jurisdiction where action for that purpose is required, other than in Canada. Prospective purchasers are required to inform themselves about, and to observe any restrictions relating to, this offering and the possession or distribution of this prospectus.

This prospectus includes a summary description of certain material agreements relating to Hydro One. See "Material Contracts". The summary description is not complete and is qualified by reference to the terms of the material agreements, which will be filed with the Canadian securities regulatory authorities and available on SEDAR at www.sedar.com. Prospective purchasers are encouraged to read the full text of such material agreements.

Any graphs, tables or other information demonstrating the historical performance of Hydro One Inc. or any other entity contained in this prospectus are intended only to illustrate past performance of such entities and are not necessarily indicative of future performance of Hydro One Limited, Hydro One Inc. or such entities.

NON-GAAP MEASURES

Hydro One Limited and Hydro One Inc. prepare and present their financial statements in accordance with U.S. GAAP.

Hydro One Limited intends to report certain non-GAAP measures in its future continuous disclosure documents after it becomes a publicly-listed company. It currently intends to report "Adjusted Net Income" and "FFO" (funds from operations), both of which are referred to (for Hydro One Inc.) in "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information". These measures are not recognized measures under U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. They are therefore unlikely to be comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under U.S. GAAP.

To the extent that "**Adjusted Net Income**" is used in future continuous disclosure documents of Hydro One Limited, it will be defined as net income, adjusted for certain items, including non-recurring items and other items that management does not consider reflect the operating performance of the Company. No adjustments to net income are presented in this prospectus. Management believes that this measure, as the Company will define it, will be helpful in assessing the Company's financial and operating performance.

"**FFO**" is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) noncontrolling interest distributions. Management believes that this measure will be helpful as a supplemental measure of the Company's operating cash flows.

FORWARD-LOOKING INFORMATION

This prospectus contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this prospectus is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: expectations regarding the ability to generate stable and growing net cash from operating activities to fund the Company's ongoing sustaining capital investments and to support a strong and growing dividend; the Company's intention to use a portion of its net cash from operating activities in combination with additional debt to fund future development capital investments; projected future capital expenditures and the nature of those capital expenditures; projected rate bases; estimates with respect to the amount of investment required to connect the East-West Tie Line to Hydro One's transmission system; the fact that the Company may consider larger-scale acquisition opportunities or other strategic initiatives outside of Ontario and that these acquisition opportunities may include other providers of electrical transmission, distribution and other similar services in Canada or in the United States; anticipated annual adjustments to the Company's revenue requirements; expectations regarding allowed return on equity; expectations regarding the ability of the Company to recover expenditures in future rates; Hydro One's expectations for industry growth and demand for electricity in Canada and the United States and new sources of electricity generation, including renewable energy; expectations regarding Hydro One's current and anticipated plans for sustaining and development capital expenditures for its distribution and transmission systems; expectations regarding anticipated levels of funds from operations or "FFO" and the ability to draw down on the Company's existing and new credit facilities; expectations regarding Hydro One's expected load growth and the impact of Hydro One's conservation and demand management requirements and targets; expectations regarding the ability to negotiate collective agreements consistent with rate orders and to maintain stable outsourcing arrangements; Hydro One's relationship with the Province and the Province's investment in Hydro One; the estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining Hydro One's allowed return on equity) on Hydro One's net income; expectations regarding the amount of the departure tax payable by Hydro One under the Electricity Act; future pension contributions and anticipated changes to Hydro One's pension plan arrangements; expectations regarding future executive compensation; expectations regarding the Governance Agreement and other agreements with the Province and the implementation of corporate governance practices and appointment of directors and officers; expectations regarding the manner in which Hydro One will operate; expectations regarding Hydro One's dividend policy and the Company's intention to declare and pay dividends, including the anticipated annual dividend amount of approximately $500 million in the aggregate initially, based on a target payout ratio of 70% to 80% of net income; the Company's intention to implement a dividend reinvestment plan and to operate the plan on a basis that does not result in significant dilution to holders of common shares; and legal proceedings in which Hydro One is currently involved.

Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target", and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this prospectus is based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for Hydro One's distribution and transmission businesses; no unfavourable changes in environmental regulation; continuing exemptive relief being granted by the Canadian securities regulatory authorities for Hydro One Limited's preparation of its financial statements in accordance with U.S. GAAP or Hydro One Limited otherwise being eligible under Canadian securities laws to prepare its financial statements in accordance with U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business of Hydro One. These assumptions are based on information currently available to Hydro One, including information obtained by Hydro One from third-party sources. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One's business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information include, among other things:

- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures,
- the risk of claims by First Nations and Métis communities related to sovereignty and jurisdiction over reserve and traditional territories, or a perceived failure by the Crown to sufficiently consult a First Nations or Métis community,
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates,
- the risk of exposure by the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or to which the Company could be subject to claims for damage,
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions,
- risks that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures,
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk,
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner,
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications,
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment and post-retirement benefits costs,
- risks associated with the Province's significant share ownership and other relationships with the Province, including potential conflicts of interest that may arise between the Company, the Province and related parties,
- the risk of future sales of common shares by the Province or issuance of additional common shares by Hydro One Limited which may adversely affect the market prices for the common shares,
- the risk that Hydro One Inc.'s liability for payment-in-lieu of tax under the Electricity Act may be impacted by the valuation of the shares and debt of Hydro One Brampton Networks Inc. and risks associated with changes to Hydro One's tax status as a result of this offering, and
- assumptions and estimates required for the preparation of pro forma financial statements may be materially different from the Company's actual results and experience in the future.

Hydro One cautions you that the above list of factors is not exclusive. Some of these and other factors are discussed in more detail under "Risk Factors". You should review such section in detail.

In addition, Hydro One cautions the reader that information provided in this prospectus regarding Hydro One's outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of Hydro One's future plans and may not be appropriate for other purposes.

MARKET AND INDUSTRY DATA

This prospectus includes market and industry data obtained from third party sources, industry publications, and publicly available information, including Natural Resources Canada's *About Electricity*, the National Energy Board's *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, the Ontario Energy Board's *Yearbook of Distributors (2014)*, the Edison Electric Institute's *2014 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry,* the U.S. Energy Information Administration's *Annual Energy Outlook 2015 with Projections to 2014* and market data sourced from Bloomberg, as well as industry and other data prepared by

Hydro One on the basis of its knowledge of the Canadian market and economy (including its estimates and assumptions relating to the Canadian market and economy based on that knowledge). Hydro One believes that this market and economic data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness thereof. The accuracy and completeness of the market and economic data used throughout this prospectus are not guaranteed and none of Hydro One, the Selling Shareholder or any of the Underwriters make any representation as to the accuracy of such information. Although Hydro One believes it to be reliable, none of Hydro One, the Selling Shareholder or any of the Underwriters has independently verified any of the data from third party sources referred to in this prospectus, nor analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic and other assumptions relied upon by such sources.

TRADE-MARKS AND TRADE-NAMES

This prospectus includes trademarks which are protected under applicable intellectual property laws and are the property of Hydro One Inc. or its subsidiaries. Solely for convenience, the trade-marks and trade-names referred to in this prospectus may appear without the ® or ™ symbols, but such references are not intended to indicate, in any way, that Hydro One will not assert, to the fullest extent under applicable law, its rights or the right of the applicable licensor to these trade-marks and trade-names. All other trademarks used in this prospectus are the property of their respective owners.

MARKETING MATERIALS

A "template version" of the following "marketing materials" (each such term as defined in National Instrument 41-101 – *General Prospectus Requirements*) for this offering filed with the securities commission or similar regulatory authority in each of the provinces or territories of Canada is specifically incorporated by reference into this prospectus:

1. the term sheet dated October 9, 2015 and filed on SEDAR on October 9, 2015; and
2. the investor presentation dated October 9, 2015 and filed on SEDAR on October 13, 2015.

The term sheet and investor presentation referred to above will be available under Hydro One Limited's profile on SEDAR at www.sedar.com.

In addition, any template version of any other marketing materials filed with the securities commission or similar regulatory authority in each of the provinces and territories of Canada in connection with this offering, after the date hereof, but prior to the termination of the distribution of the common shares under this prospectus (including any amendments to, or an amended version of, any template version of any marketing materials), is deemed to be incorporated by reference herein. Any template version of any marketing materials utilized in connection with this offering are not part of this prospectus to the extent that the contents of the template version of the marketing materials have been modified or superseded by a statement contained in this prospectus.

PROSPECTUS SUMMARY

The following is a summary of the principal features of this offering and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. This summary does not contain all of the information prospective investors should consider before investing in Hydro One Limited's common shares. Please refer to the "Glossary" for a list of defined terms used herein.

ELECTRICITY INDUSTRY

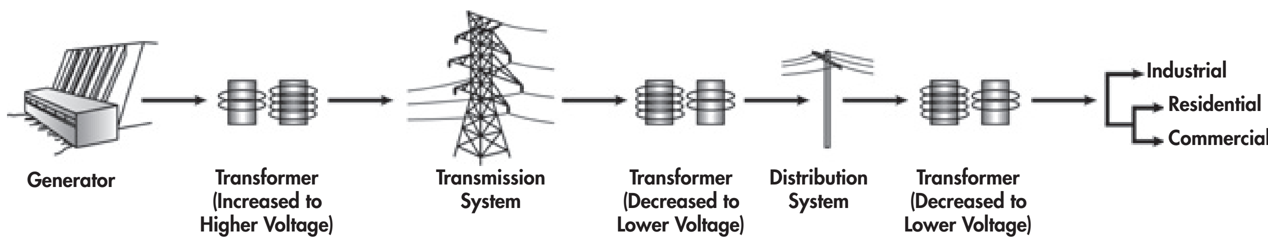
Overview

The electricity industry is made up of businesses that generate, transmit, distribute and sell electricity. Hydro One's business is focused on the transmission and distribution of electricity.

- Transmission refers to the delivery of electricity over high voltage lines, typically over long distances, from generating stations to local areas and large industrial customers.
- Distribution refers to the delivery of electricity over low voltage power lines to end users such as homes, businesses and institutions.

Overview of an Electricity System

The basic configuration of a typical electricity system showing electricity generation, transmission and distribution is illustrated in the following diagram:



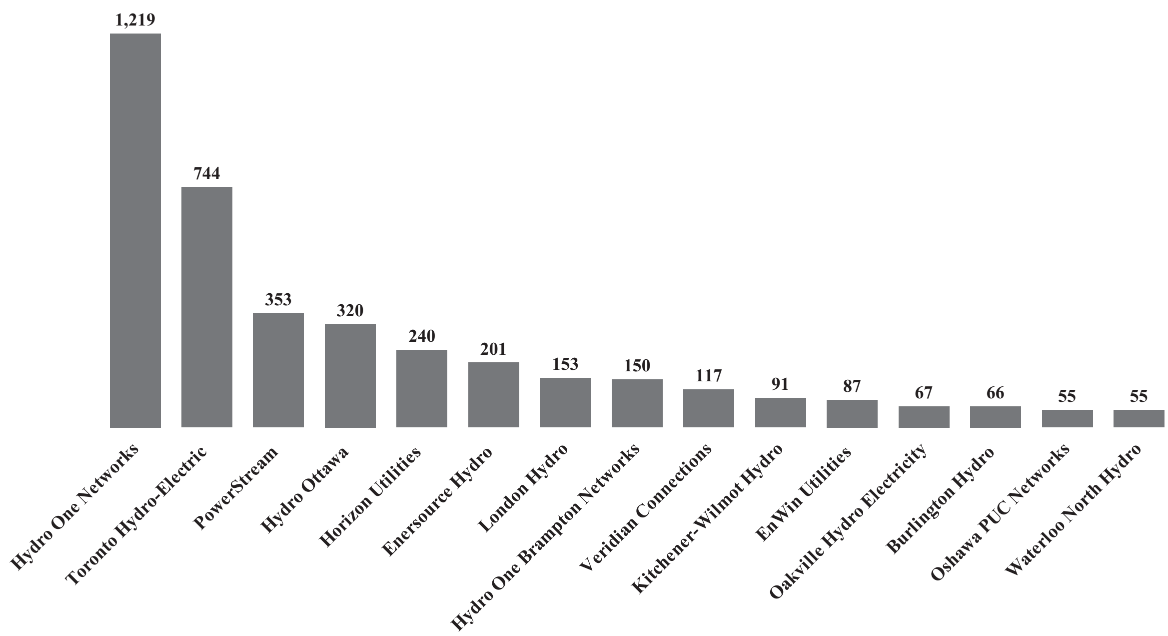
Transmission of Electricity in Ontario

Transmission companies own and operate transmission systems that deliver electricity over high voltage lines. Hydro One's transmission system accounts for 96% of Ontario's electricity transmission network. Investments in transmission infrastructure are required to ensure the safe and reliable delivery of electricity. These investments are made to maintain the function and reliability of transmission systems, accommodate increased demand for electricity and respond to developments affecting the electricity industry. Developments with respect to electricity generation often have a direct impact on transmission companies, since significant investments in transmission systems may be required to accommodate new generation sources (such as renewable energy) or the retirement of existing generation facilities (such as coal-fired facilities). Major changes affecting the generation of electricity must be closely coordinated with transmission considerations in mind. Recent discussions and initiatives by provincial governments to examine opportunities for Ontario to import additional electricity from Québec and Newfoundland and Labrador may also require new transmission infrastructure. These types of investments are in addition to the investments that transmission companies must undertake to sustain their existing assets, maintain reliability and provide connections to the transmission system.

Distribution of Electricity in Ontario

Distributors own and operate distribution systems that deliver electricity over low voltage power lines to end users. Distributors in Ontario are also known as "local distribution companies". In Ontario, 72 local distribution companies currently provide electricity to approximately five million customers. The distribution industry in Ontario is fragmented, with the 15 largest local distribution companies accounting for approximately 78% of the province's five million customers. Hydro One owns the largest local distribution company in Ontario, Hydro One Networks Inc., with approximately 1.3 million customers, or approximately 25% of the total number of customers in Ontario.

15 Largest Distributors in Ontario(1)
(Thousands of Customers)



Notes:

(1) Source: *Ontario Energy Board Yearbook of Distributors* (2014). For Hydro One Networks Inc., the 1,219 figure excludes certain classes of customers which are included in the total number of customers reported elsewhere in this prospectus.

(2) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc.

Most of the local distribution companies in Ontario are owned or jointly owned by municipalities. A local distribution company is responsible for distributing electricity to customers in its service territory, which may cover large portions or all of a particular municipality, or an otherwise-defined geographic area.

To create more efficiencies in the distribution sector, the Premier's Advisory Council on Government Assets has endorsed the need for faster consolidation among local distribution companies in Ontario. The Province has responded by announcing tax incentives in the 2015 Ontario Budget which are intended to promote consolidation.

For more information, see "Electricity Industry".

RATE-REGULATED UTILITIES

Overview

The rates charged for electricity transmission and distribution services are regulated in Canada and many other jurisdictions. The term “rate-regulated” is used to refer to an electricity business whose rates for transmission, distribution or other services are subject to approval by a regulator. The Ontario Energy Board is the regulator responsible for approving electricity transmission and distribution rates in Ontario.

In Canada, regulators generally use two different models for approving the rates charged by rate-regulated utilities: (i) a “cost of service” model, and (ii) a “performance-based” model (sometimes also referred to as an “incentive-based” model).

In a cost of service model, a utility charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. The costs of providing its services must be prudently-incurred.

In a performance-based model, a utility also charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. However, the rates charged by the utility in a performance-based model assume that the utility becomes increasingly efficient over time, resulting in lower costs to provide the same service. If a utility achieves cost savings in excess of those established by the regulator, the utility may retain some or all of the benefits of those cost savings, which may permit the utility to earn more than its allowed return on equity.

Value Drivers for a Rate-Regulated Utility

Management believes that the key drivers of value for a rate-regulated utility are:

- the utility’s rate base,
- the utility’s deemed capital structure, as set by the regulator,
- the utility’s allowed return on equity, as set by the regulator,
- capital expenditures that ultimately add to the utility’s rate base,
- the ability to generate efficiencies and cost savings in the operations of the utility, and
- the ability to maintain a constructive relationship with its regulator.

For a description of these drivers, see “Rate-Regulated Utilities”.

BUSINESS OF HYDRO ONE

Overview

Upon completion of this offering, Hydro One Limited will be one of Canada's largest publicly-listed electricity companies, measured by assets. With a stable regulated business, strong "A" category credit ratings and projected increases in its rate base, Hydro One expects to continue generating stable and growing net cash from operating activities to fund its ongoing sustaining capital investments and to support a strong and growing dividend. The Company will operate independently of the Province and will be overseen by an experienced and independent board of directors.

Investment Highlights

Stable Regulated Cash Flows and Strong Balance Sheet

The transmission and distribution of electricity are essential infrastructure services. Hydro One's transmission and distribution businesses are fully rate-regulated and represent 99% of its overall business, measured by revenues. These businesses generate stable and growing net cash from operating activities and net income. Hydro One's net cash from operating activities grew to $1,256 million in 2014 from $892 million in 2009 and $911 million in 2004, representing a compound annual growth rate of 7.1% and 3.3% on a five and ten year basis, respectively. Hydro One's net income grew to $747 million in 2014 from $470 million in 2009 and $498 million in 2004, representing a compound annual growth rate of 9.7% and 4.1% on a five-and ten-year basis, respectively.

Hydro One Inc. has been a reporting issuer in Canada for over 15 years and has been an active participant in the public debt markets. Hydro One Inc. has one of the strongest credit profiles of any public company regulated electricity utility in Canada, with its debt currently rated A (stable) by Standard & Poor's, A2 (negative) by Moody's, and A (high) (under review with developing implications) by DBRS. Standard & Poor's has also assigned a long-term corporate credit rating to Hydro One Limited of A (stable). Hydro One Inc. has a strong track record of raising capital in the public debt markets, and has raised over $3.2 billion in gross proceeds through the sale of debt in the past three and a half years alone. Management expects that maintaining a strong credit profile and a low cost of borrowing will be a key element of Hydro One's business and regulatory strategy following this offering, and that Hydro One will have significant debt capacity to fund future investments. Hydro One Inc. will remain a reporting issuer in Canada following the closing of this offering. Hydro One Limited does not intend to provide a guarantee in respect of Hydro One Inc.'s debt.

Driven by a stable regulated business, strong "A" category credit ratings and projected increases in its rate base, Hydro One expects to continue generating stable and growing net cash from operating activities to fund its ongoing sustaining capital investments and to support a strong and growing dividend. Additionally, the Company intends to use a portion of its net cash from operating activities in combination with additional debt to fund future development capital investments.

Robust and Predictable Growth Profile

Additions to Rate Base through Approved Capital Expenditures

Hydro One must continually invest in its transmission and distribution businesses in order to provide safe and reliable electricity service and meet its obligations as a regulated utility. A significant number of Hydro One's transmission and distribution assets were built in the 1960s and 1970s or earlier and are reaching the end of their service lives. The Company therefore expects that it will be required to make significant investments in its existing infrastructure over the long term. Over the past five fiscal years, the Company has spent an average of $1.5 billion per year on capital expenditures. When placed into service, these investments add to Hydro One's rate base, which grew during that period from $11.6 billion to $16.3 billion, representing a compound annual growth rate of 7.1%.

The Company incurs capital expenditures to maintain safety, reliability and integrity of its transmission and distribution assets and to allow for prudent growth necessary to continue to meet the evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital expenditures, which are required to support the continued operation of Hydro One's existing assets, and development capital expenditures, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations. Sustaining capital expenditures are recurring in nature and involve less regulatory and completion risk compared to large scale development projects.

Hydro One anticipates that it will spend an average of $1.5 billion per year over the next five years on total capital expenditures, with sustaining capital expenditures representing an average of approximately 60% of total capital expenditures in each year. The Company anticipates that these investments will contribute to improved reliability, customer service and operating efficiencies, as well as increased net cash from operating activities and net income from a growing rate base.

Projected Capital Expenditures for Transmission and Distribution Businesses	**2015**	**2016**	**2017**	**2018**	**2019**
			(millions)		
Transmission	$ 899	$ 866	$ 848	$ 839	$ 832
Distribution	$ 665	$ 669	$ 674	$ 678	$ 682
Total	**$1,564**	**$1,535**	**$1,522**	**$1,517**	**$1,514**

Projected Capital Expenditures by Category	**2015**	**2016**	**2017**	**2018**	**2019**
			(millions)		
Sustaining	$ 905	$ 891	$ 955	$1,022	$ 978
Development	$ 470	$ 444	$ 381	$ 321	$ 379
Other	$ 189	$ 200	$ 186	$ 174	$ 157
Total	**$1,564**	**$1,535**	**$1,522**	**$1,517**	**$1,514**

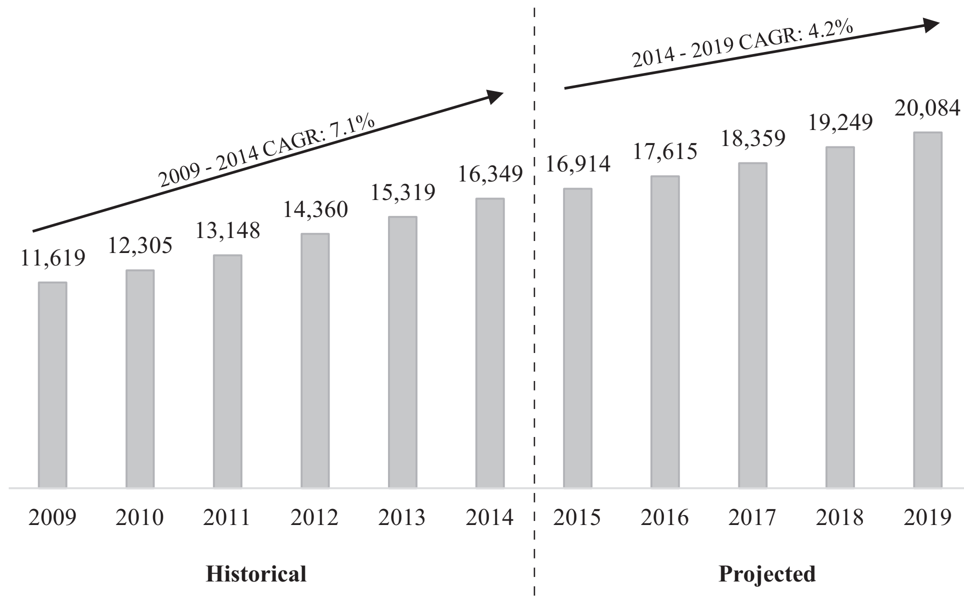
Notes:

(1) Projected capital expenditures may be considered forward-looking information, and reflect the Company's current expectations and assumptions relating to projects contemplated in the Company's capital expenditure programs and Ontario Energy Board approvals received to date. Transmission capital expenditures for 2015 and 2016 were previously approved by the board of directors of Hydro One Inc. and are consistent with the capital expenditures information presented in the most recent transmission rates application filed with the Ontario Energy Board, which led to the Ontario Energy Board's approval of Hydro One's 2015 rate order for transmission services. Distribution capital expenditures for 2015, 2016 and 2017 were previously approved by the board of directors of Hydro One Inc. and are consistent with the capital expenditures information presented in the most recent distribution rate application filed with the Ontario Energy Board, which led to the Ontario Energy Board's distribution rates decision for Hydro One's 2015, 2016 and 2017 years. Actual capital expenditures for any of the years referred to above may be greater or less than projected capital expenditures. See "Forward-Looking Information". See "Risk Factors" for a discussion of material factors that could cause actual capital expenditures to differ from projected capital expenditures.

(2) "Other" capital expenditures consist of special projects, such as those relating to information technology.

The impact of Hydro One's capital expenditures on its rate base is illustrated in the following graph, which shows both the historical rate base of Hydro One for the past five fiscal years and its projected rate base over the next five fiscal years through the addition of assets that are anticipated to be placed into service.

Rate Base
($ millions)



Notes:

(1) "CAGR" means compound annual growth rate.

(2) Projected rate base may be considered forward-looking information. The rate base in each year represents the combined rate base for Hydro One's transmission and distribution businesses. The transmission rate bases of Hydro One Networks Inc. for 2015 and 2016 have been approved by the Ontario Energy Board, subject to certain conditions in respect of in-service additions. The distribution rate bases of Hydro One Networks Inc. for 2015, 2016 and 2017, have been approved by the Ontario Energy Board. Transmission rate bases for 2017, 2018 and 2019, and distribution rate bases for 2018 and 2019, are projected based on Hydro One's current expectations and assumptions regarding investments in its transmission and distribution infrastructure and the timing of assets being included in Hydro One's rate base, and will be subject to Ontario Energy Board approval in connection with Hydro One's rate applications for those years. Transmission rate bases for 2017, 2018 and 2019, and distribution rate bases for 2018 and 2019, as approved by the Ontario Energy Board, may be higher or lower than the rate bases shown. See "Forward-Looking Information".

Development Capital Projects

Hydro One anticipates spending an average of approximately $400 million per year over the next five years on development capital projects for its transmission and distribution businesses. These capital projects typically involve longer development timelines. Hydro One has significant development experience, having designed and built substantially all of Ontario's transmission system and a large portion of its distribution system. This includes the Bruce-to-Milton transmission project, which was completed in 2012 on budget and six months ahead of schedule. This was the largest transmission infrastructure project in Ontario in 20 years and involved the construction of approximately 700 transmission towers and approximately 180 kilometres of double circuit lines. More recently, Hydro One was selected to develop the Northwest Bulk Transmission Line, another large scale transmission project that, if approved by the Ontario Energy Board, would reinforce the connection between Thunder Bay and Dryden.

As the Company owns substantially all of Ontario's transmission network, the Company believes that additional development opportunities for Hydro One may arise as a result of the requirement to connect new transmission lines to Hydro One's transmission system, even where Hydro One may not be the developer of the new line. For instance, in the case of the East-West Tie Line, which is being developed by NextBridge Infrastructure, management estimates that Hydro One may need to invest over $100 million in station upgrades in order to connect the new line to Hydro One's transmission system if the project is approved by the Ontario Energy Board.

Acquisition Opportunities

As the largest distributor in Ontario, Hydro One has been an active consolidator of local distribution companies. In the late 1990s and early 2000s, when significant changes were made to the electricity sector in Ontario, Hydro One acquired 88 individual local distribution companies, which were subsequently integrated into Hydro One's distribution business (with the exception of Hydro One Brampton Networks Inc., which was operated as a stand-alone entity). More recently, the Company acquired Haldimand Hydro in June 2015 and Norfolk Power in August 2014, adding more than 40,000 customers to its distribution network. A third Hydro One acquisition, of Woodstock Hydro, received Ontario Energy Board approval on September 11, 2015 and is expected to close later in 2015. Through these recent acquisitions, the Company will have increased its customer base by approximately 5%. Hydro One will continue to evaluate local distribution company consolidation opportunities in Ontario in the future and intends to pursue those acquisitions which deliver value to the Company and its shareholders.

Over time, the Company may also consider larger-scale acquisition opportunities or other strategic initiatives outside of Ontario to diversify its asset base and leverage its strong operational expertise. These acquisition opportunities may include other providers of electrical transmission, distribution and other similar services in Canada or in the United States.

Significant Scale and Leadership Position in Ontario

Hydro One plays an essential role in the electricity system of Canada's most populous province. Hydro One owns and operates substantially all of Ontario's transmission system, and is also the largest electricity distributor in Ontario. Management believes that Hydro One's significant scale and leading position in the electricity industry in Ontario provide it with several key competitive advantages that may not be available to smaller utilities, including:

- a low cost of borrowing and broad access to debt capital markets in order to fund its development and growth initiatives,
- the ability to draw on a large and highly experienced in-house team of experts covering all key aspects of Hydro One's business, including asset management, operations, post-outage recovery, project design, engineering, procurement, project management and construction,
- the resources and commitment to prudently invest in innovation, continuous improvement and customer service initiatives and to improve the reliability and performance of Hydro One's transmission and distribution systems and reduce operations, maintenance and administration costs,
- a refined and comprehensive stakeholder engagement process that covers Hydro One's customers, municipalities, remote communities and other parties,
- extensive experience building and maintaining effective relationships with First Nations and Métis communities, and
- a leading role in working with regulatory authorities on developments with respect to energy policy, regulatory changes, new transmission and distribution investments, regional planning and new technologies.

Management believes that these strengths have increased Hydro One's operational effectiveness, helped it maintain a positive and constructive relationship with its regulators, customers and stakeholders and ultimately contributed to achieving successful outcomes in its applications for the approval of transmission and distribution rates, new development projects and the acquisition of local distribution companies.

Consistent and Stable, Rate-Regulated Environment

Hydro One's transmission and distribution businesses operate in a stable, rate-regulated environment. Management believes the Ontario Energy Board is regarded in the electricity industry as a stable and sophisticated regulator with a transparent and predictable rate setting process. The allowed return on equity determined by the Ontario Energy Board is set by a formula linked to long-term government bond yields and corporate bond spreads. See "Rate-Regulated Utilities – Value Drivers for a Rate-Regulated Utility – Return on Equity". Hydro One does not set the price of electricity and has no direct exposure to electricity price risk because the cost of electricity is passed on directly to consumers. The rates approved by the Ontario Energy Board for transmission and distribution services are intended to allow utilities to recover their cost of providing services and earn an allowed return on equity, while achieving productivity gains for the mutual benefit of utilities and their customers.

Over the past six years, the Company's allowed return on equity approved by the Ontario Energy Board has ranged from 8.39% to 9.66% for its transmission business and 9.30% to 9.85% for its distribution business.

Allowed Return on Equity

	2010	2011	2012	2013	2014	2015
Transmission	8.39%	9.66%	9.42%	8.93%	9.36%	9.30%
Distribution	9.85%	9.66%	9.66%	9.66%	9.66%	9.30%

Notes:

(1) Management anticipates that the return on equity set by the Ontario Energy Board will be lower in 2016 compared to 2015 due to decreases in interest rates.

Hydro One has earned or exceeded its allowed return on equity on a consolidated basis. For instance, the Company's actual returns on equity were 10.60% in 2010, 10.50% in 2011, 11.50% in 2012, 11.50% in 2013 and 10.00% in 2014, in each case, on a consolidated basis.

Proven Senior Management Team and Experienced, Independent Board of Directors

Following this offering, Hydro One Limited will operate as an independent, commercially-oriented public company, with an experienced, independent board of directors and proven senior leadership team. Hydro One's current leadership has demonstrated the capability to execute Hydro One's strategic plan and drive performance improvements and shareholder returns. The Company will operate with an independent board of directors and autonomous decision-making. As a shareholder of Hydro One Limited, the Province will engage in the business and affairs of Hydro One as an investor and not as a manager, as contemplated by the Governance Agreement. To support Hydro One's new direction, a new board of directors and senior leadership team were appointed in connection with this offering. Members of the new board of directors meet high standards of independence, commercial experience and director expertise and will oversee the Company's strategy, operations and growth as a publicly-listed company. The group includes Canadian business leaders, electricity sector experts, corporate directors and a former provincial Ombudsman.

Hydro One will be led by a highly experienced management team that together has extensive industry, operating and public company experience. Mayo Schmidt, the Company's new President and Chief Executive Officer, was formerly the Chief Executive Officer of Viterra Inc. and its predecessor, Saskatchewan Wheat Pool. Mr. Schmidt has a track record of leading large scale business transformation and growth while generating value and benefits for investors, employees and customers. At Viterra, Mr. Schmidt transformed a relatively small regional co-operative into a publicly-held, multi-billion dollar corporation with nearly 7,000 employees and operations around the world. In recognition of his accomplishments at Viterra, Mr. Schmidt was named "Chief Executive of the Year in 2009" by Canadian Business Magazine. Michael Vels, the Company's new Chief Financial Officer, was formerly the Chief Financial Officer of Maple Leaf Foods Inc. Mr. Vels brings to Hydro One considerable executive level experience in public company governance, debt and equity capital raising, mergers and acquisitions, business transformation and information technology. Mr. Schmidt and Mr. Vels join an established management team at Hydro One that has extensive experience with the Company's operations, assets and regulators. Mr. Schmidt and Mr. Vels are committed to improving the management of the Company and driving performance improvements and cultural change.

GOVERNANCE AGREEMENT

Concurrently with the closing of this offering, Hydro One Limited will enter into the Governance Agreement with the Province. The purpose of the Governance Agreement is to prescribe the role of the Province, as a holder of Voting Securities, in the governance of Hydro One Limited. Although the Governance Agreement does not address all aspects of the governance of Hydro One Limited, it comprehensively deals with, and limits, the role of the Province in that governance. It describes the principles that govern how Hydro One Limited will be managed and operated, including that the Province, in its capacity as a holder of Voting Securities, will engage in the business and affairs of Hydro One Limited as an investor and not as a manager. It also contains commitments by the Province restricting the exercise of its rights as a holder of Voting Securities.

The Governance Agreement specifically addresses the following matters: (i) the governance principles under which Hydro One Limited and its subsidiaries will be managed and operated; (ii) the nomination of directors, which includes: (a) the requirement for a fully independent board of directors (other than the Chief Executive Officer), and (b) the maximum number of directors that may be nominated by the Province; (iii) the election and replacement of directors; (iv) approvals requiring a special resolution of the directors; (v) restrictions on the right of the Province to initiate fundamental changes; (vi) pre-emptive rights provided to the Province with respect to future issuances of Voting Securities by Hydro One Limited; and (vii) limits with respect to the Province's acquisition of outstanding Voting Securities. See "Governance and Relationship with Principal Shareholder." For a description of the governance of Hydro One Limited more generally, see "Directors and Management of the Company".

THE OFFERING

Issuer:	Hydro One Limited.
Selling Shareholder:	The Province.
Offering:	81,100,000 common shares of Hydro One Limited to be sold by the Province (89,250,000 common shares if the Over-Allotment Option is exercised in full). See "Plan of Distribution". It is anticipated that the base offering will represent 13.63% of the common shares of Hydro One Limited issued and outstanding immediately prior to the closing of this offering. Assuming full exercise of the 10% over-allotment option, this offering will represent 15% of the common shares of Hydro One Limited issued and outstanding immediately prior to the closing of this offering.
Offering Price:	$20.50 per common share.
Offering Size:	$1,662,550,000, before giving effect to the Over-Allotment Option ($1,829,625,000 if the Over-Allotment Option is exercised in full).
Over-Allotment Option:	The Province has granted to the Underwriters the Over-Allotment Option, exercisable, in whole or in part, at any time for a period of 30 days after the Closing Date, to purchase from the Province up to an additional 8,150,000 common shares, on the same terms as set out above solely to cover over-allotments, if any.
Common Shares Outstanding Following Closing:	Immediately following the closing of this offering and the other transactions described in "Principal and Selling Shareholder – Share Purchase Arrangements with the Province", 595,000,000 common shares will be issued and outstanding. See "Principal and Selling Shareholder".
Common Shares Held by the Selling Shareholder Following Closing:	Immediately following the closing of this offering and the other transactions described in "Principal and Selling Shareholder – Share Purchase Arrangements with the Province", the Province will hold approximately 85% of Hydro One Limited's total issued and outstanding common shares (approximately 84% if the Over-Allotment Option is exercised in full). See "Principal and Selling Shareholder".
Proceeds to the Selling Shareholder:	The net proceeds to the Selling Shareholder from this offering will be approximately $1,635,949,200 after deducting the Underwriters' Fee referred to on the cover page of this prospectus but before deducting the expenses of this offering. If the Over-Allotment Option is exercised in full, the net proceeds to the Selling Shareholder from this offering will be approximately $1,800,351,000 after deducting the Underwriters' Fee referred to on the cover page of this prospectus (assuming that 70% of the common shares offered under this prospectus are sold to institutional investors) but before deducting the expenses of this offering. Hydro One Limited will not receive any proceeds from this offering. See "Use of Proceeds".
Dividend Policy:	The Board is expected to establish a dividend policy pursuant to which Hydro One Limited will pay a quarterly dividend, initially in the amount of $0.21 per common share. The annual amount of the dividend is anticipated to be approximately $500 million in the aggregate initially, based on a target payout ratio of 70% to 80% of net income. Assuming the closing of this offering occurs on November 5, 2015, the first dividend for the period from the closing of this offering to March 17, 2016 is expected to be paid on or about March 31, 2016 to shareholders of record on March 17, 2016. The payment of dividends is not guaranteed and the amount and timing of any dividends payable will be at the discretion of the Board. Hydro One intends to increase its debt as its rate base increases in order to maintain debt at 60% of its rate base and does not anticipate any increases in debt to fund the payment of dividends, although it may draw on its revolving credit facilities for general purposes. See "Dividends – Dividend Policy".
Dividend Reinvestment Plan:	Following the closing of this offering and subject to the receipt of any required regulatory approvals, Hydro One Limited intends to adopt a dividend reinvestment plan pursuant to which resident Canadian holders of common shares will be entitled to elect

	to have all of the cash dividends of Hydro One Limited payable to them automatically reinvested in additional common shares, which will be either purchased on the open market or issued from treasury. The dividend reinvestment plan is currently intended to operate on a basis that does not result in significant dilution to holders of common shares. See "Dividends – Dividend Reinvestment Plan".
Lock-Up:	During the period beginning on the closing date of this offering and ending on the date that is 180 days following the closing date of this offering, each of Hydro One Limited and the Selling Shareholder will not, directly or indirectly, without the prior written consent of RBC Dominion Securities Inc. and Scotia Capital Inc., on behalf of the Underwriters, issue, sell, offer or grant any option, warrant or other right to purchase or agree to issue or sell, or otherwise lend, transfer, assign, pledge or dispose of any common shares or other securities of Hydro One Limited or other securities convertible into, exchangeable for, or otherwise exercisable into the common shares or other equity securities of Hydro One Limited or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, subject to certain exceptions. See "Plan of Distribution".
Pre-Closing Transactions:	Certain pre-closing transactions will occur prior to the closing date of this offering. This will include steps taken to complete the acquisition of Hydro One Inc. by Hydro One Limited, recapitalize Hydro One Inc.'s subsidiary, Hydro One Networks Inc., and pay a dividend or make a return of capital to the Province in the amount of $800 million. See "Pre-Closing Transactions".
Risk Factors:	Investors should read the "Risk Factors" section of this prospectus for a discussion of factors to consider carefully before deciding to invest in Hydro One Limited's common shares. These risks include, without limitation: **Risks Relating to Hydro One's Business** • Regulatory Risks and Risks Relating to Hydro One's Revenues • First Nations and Métis Claims Risk • Risk of Natural and Other Unexpected Occurrences • Risks Associated with Information Technology Infrastructure and Data Security • Work Force Demographic Risk and Labour Relations Risk **Risks Relating to the Company's Relationship with the Province** • Ownership by the Province and Voting Power • Continued Influence by the Province • Nomination of Directors and Confirmation of Chief Executive Officer and Chair • Board Removal Rights • 10% Ownership Restriction • Potential Difficulties in Enforcing Civil Liabilities Against the Province, Hydro One Limited and Other Persons **Risks Relating to this Offering** • Absence of a Prior Public Market • Potentially Volatile Market Price for Common Shares • Payment of Dividends • Tax Risks Relating to this Offering • Pro Forma Financial Information • First Nations and Métis Proceedings The above list of risk factors is not exclusive. These and other risk factors are discussed in more detail under "Risk Factors".

SUMMARY CONSOLIDATED FINANCIAL INFORMATION

The following presents historical and pro forma summary consolidated financial information of Hydro One Inc., in each case, for the periods ended and as at the dates indicated below. The selected consolidated financial information has been derived from the unaudited interim financial statements of Hydro One Inc. as at and for the three and six month periods ended June 30, 2015 and June 30, 2014 and the audited consolidated financial statements of Hydro One Inc. as at and for the years ended December 31, 2014, December 31, 2013 and December 31, 2012 appearing elsewhere in this prospectus. Hydro One's historical results for any prior period are not necessarily indicative of its results to be expected in any future period. The selected pro forma condensed financial information as at and for the six months ended June 30, 2015 and for the year ended December 31, 2014 has been derived from the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, and give effect to the transactions described in the notes to those statements as if they had occurred on January 1, 2014 for the unaudited pro forma condensed consolidated statements of operations and June 30, 2015 for the unaudited pro forma condensed consolidated balance sheet. Those transactions relate to the following events:

- the payment by Hydro One Inc. and certain of its subsidiaries of the "departure tax", as described in "Departure Tax",
- the recognition by Hydro One Inc. of a deferred tax asset as a consequence of leaving the payments in lieu of corporate income taxes ("**PILs**") regime and entering the corporate tax regime (see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results of Operations – Payments in Lieu of Corporate Income Taxes"),
- the recapitalization of Hydro One Networks Inc., as described in "Pre-Closing Transactions", and
- the transfer of all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province, as described in "Pre-Closing Transactions".

The selected pro forma condensed financial information is unaudited, for informational purposes only, and not necessarily indicative of what Hydro One Inc.'s financial position or results of operations would have been had such transactions been completed as at the dates indicated and does not purport to represent what the financial position or results of operations might be for any future period.

The following information should be read in conjunction with "Risk Factors", "Consolidated Capitalization", "Management's Discussion and Analysis of Financial Condition and Results of Operations", the consolidated financial statements of Hydro One Inc., and the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. and the related notes included elsewhere in this prospectus. The financial statements of Hydro One Inc. included in this prospectus have been prepared in accordance with U.S. GAAP.

Statement of Operations Data[(1)]	Six Months Ended June 30		
	2015	2015	2014
	(pro forma)		
	($, in millions)		
Revenues			
Distribution	2,320	2,574	2,497
Transmission	770	770	804
Other	27	27	29
Total revenues	3,117	3,371	3,330
Costs			
Purchased power	1,590	1,808	1,746
Operation, maintenance and administration	546	560	645
Depreciation and amortization	368	377	348
Total costs	2,504	2,745	2,739
Income before financing charges and provisions for payments in lieu of corporate income taxes	**613**	**626**	**591**
Financing charges	193	187	185
Provision for payments in lieu of corporate income taxes	64	68	51
Net income[(3)]	**356**	**371**	**355**

Statement of Operations Data(1)	2014 (pro forma)	2014	2013	2012
	Year ended December 31			
	($, in millions)			
Revenues				
Distribution	4,408	4,903	4,484	4,184
Transmission	1,588	1,588	1,529	1,482
Other	57	57	61	62
Total revenues	6,053	6,548	6,074	5,728
Costs				
Purchased power	2,993	3,419	3,020	2,774
Operation, maintenance and administration	1,165	1,192	1,106	1,071
Depreciation and amortization	708	722	676	659
Total costs	4,866	5,333	4,802	4,504
Income before financing charges and provisions for payments in lieu of corporate income taxes	**1,187**	**1,215**	**1,272**	**1,224**
Financing charges	392	379	360	358
Provision for payments in lieu of corporate income taxes	87	89	109	121
Net income(4)(5)	708	747	803	745

Selected Balance Sheet Data(1)(2)	As at June 30 2015 (pro forma)	As at June 30 2015	As at December 31 2014	As at December 31 2013	As at December 31 2012
	($, in millions)				
Total assets	23,871	23,167	22,550	21,625	20,811
Long-term debt (including current portion)	10,090	9,290	8,925	9,057	8,479

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the historical summary data appearing in the table above include the assets, liabilities and results of operations of Hydro One Brampton Networks Inc. during the periods and as at the dates indicated, except in the columns marked as "pro forma".

(2) Prior to the closing of this offering, Hydro One Limited will issue $418 million of Series 1 preferred shares to the Province at a price of $25.00 per share. The existing preferred shares of Hydro One Inc. held by the Province will be cancelled. The initial dividend amount on the Series 1 preferred shares will be $1.0625 per share per year, and the dividend rate will be reset every five years in accordance with the terms of such shares. See "Description of Share Capital – Preferred Shares".

(3) Net income presented is before the payment of dividends on preferred shares of Hydro One Inc. and prior to net income (loss) attributable to noncontrolling interest. Net income is therefore not equivalent to net income attributable to common shareholders. Dividends on preferred shares of Hydro One Inc. were $9 million for each of the six months ended June 30, 2015 and 2014. Net income attributable to noncontrolling interest for the six months ended June 30, 2015 was $3 million and for the six months ended June 30, 2014 was nil.

(4) Net income presented is before the payment of dividends on preferred shares of Hydro One Inc. and prior to net income (loss) attributable to noncontrolling interest. Net income is therefore not equivalent to net income attributable to common shareholders. Dividends on preferred shares of Hydro One Inc. were $18 million for each of the years ended December 31, 2014, 2013 and 2012. Net loss attributable to noncontrolling interest for the year ended December 31, 2014 was $2 million and for each of the years ended December 31, 2013 and 2012 were nil.

(5) Pro forma net income of Hydro One Inc. for the year ended December 31, 2014 reflects an estimated deferred tax asset adjustment arising as a result of Hydro One leaving the PILs regime and entering the corporate tax regime. See "Departure Tax". This estimated deferred tax asset adjustment was based on an estimated fair market value of Hydro One's net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion payable by Hydro One as referred to in "Departure Tax". This estimated fair market value of Hydro One's net assets was determined by Hydro One principally using a discounted cash flow approach for certain assets and an asset-based approach for other assets, and was used in calculating the amount of the departure tax payable that was agreed between Hydro One and the Province in early September 2015. The actual amount of the deferred tax asset for the year ended December 31, 2015 will be based on the actual fair market value of Hydro One's net assets, which will be determined following pricing of this offering. The departure tax payable by Hydro One has been fixed at $2.6 billion, and will not be adjusted based on the fair market value of Hydro One's net assets as finally determined. Net income for the year ended December 31, 2015 will reflect the payment of the departure tax and recognition of the actual amount of the deferred tax asset, which may be different from the recognition of the estimated deferred tax asset reflected in pro forma net income of Hydro One Inc. for the year ended December 31, 2014. As a result, net income for the year ended December 31, 2015 may be impacted by the difference, if any, between the actual and estimated fair market value of Hydro One's net assets. Any impact on net income as a result of such difference will be non-cash-related and will only impact net income for the year ended December 31, 2015 and not subsequent years. The Company estimates that a $1,000 million increase or decrease in the fair market value of Hydro One's net assets would result in a corresponding increase or decrease in the deferred tax asset, and therefore net income, of approximately $200 million.

Other Financial Measures[1]	Six months ended June 30 2015	Six months ended June 30 2014	Year ended December 31 2014	Year ended December 31 2013	Year ended December 31 2012
	($, in millions)				
Reconciliation of net income to adjusted net income					
Net income	371	355	747	803	745
Adjustments	—	—	—	—	—
Adjusted net income[2]	**371**	**355**	**747**	**803**	**745**
Reconciliation of net cash from operating activities to FFO					
Net cash from operating activities	713	334	1,256	1,404	1,294
Change in non-cash operating working capital	59	304	55	(11)	31
Preferred dividends	(9)	(9)	(18)	(18)	(18)
Noncontrolling interest distributions[3]	(2)	—	—	—	—
FFO[2][4]	**761**	**629**	**1,293**	**1,375**	**1,307**

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the other financial measures appearing in the table above include amounts contributed by Hydro One Brampton Networks Inc. during the periods indicated.

(2) Adjusted net income and FFO are non-GAAP measures. See "Non-GAAP Measures".

(3) In 2014, there was a $72 million noncontrolling interest contribution. This was a one-time item, and has been excluded from the calculation of FFO in 2014.

(4) FFO, as shown, has been calculated based on the historical financial information of Hydro One Inc. and does not reflect any of the pro forma adjustments set out in the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, including the net pro forma reduction in cash tax of $56 million for the year ended December 31, 2014 and $49 million for the six month period ended June 30, 2015. See note 2C(vi) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus.

Operating Statistics and Other Information (Including Hydro One Brampton Networks Inc. except where noted)[1]	Year Ended December 31 2014	Year Ended December 31 2013	Year Ended December 31 2012
Transmission			
Electricity transmitted (TWh)	139.8	140.7	141.3
Total transmission lines spanning the province (circuit-kilometres)	29,344	29,344	29,327
Rate base[2] ($ millions)	9,934	9,353	8,774
Capital investments ($ millions)[5]	845	714	776
Distribution			
Electricity distributed to Hydro One customers (TWh)	29.8	29.8	29.2
Electricity distributed through Hydro One lines (TWh)	42.4	42.5	42.4
Total distribution lines spanning the province (circuit kilometres)	123,657	122,853	121,525
Distribution customers (Hydro One Networks Inc.)[4]	1,268,745	1,270,817	1,236,526
Distribution customers (Hydro One Brampton Networks Inc.)	149,681	146,039	141,860
Rate base[2] ($ millions)	6,315	5,925	5,550
Capital investments ($ millions)[5]	680	673	671
Certain Operating Statistics for Hydro One Brampton Networks Inc.[3]			
Total distribution lines (circuit kilometres)	3,242	3,104	2,952
Distribution customers	149,681	146,039	141,860

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the summary operating statistics appearing in the table above include amounts contributed by Hydro One Brampton Networks Inc. during the periods indicated.

(2) Rate base in each year refers to the rate base of Hydro One Networks Inc.'s transmission business or distribution business, as the case may be, approved by the Ontario Energy Board for that year. See "Meaning of Certain References".

(3) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See “Pre-Closing Transactions” for additional detail concerning the transfer and related transactions.

(4) Includes certain classes of customers which are excluded in the *Ontario Energy Board Yearbook of Distributors* (2014).

(5) Capital investments consists of capital expenditures presented in Hydro One’s consolidated statement of cash flows, adjusted for capitalized depreciation, if any, and net changes in related accruals.

ELECTRICITY INDUSTRY

Overview

The electricity industry is made up of businesses that generate, transmit, distribute and sell electricity. Hydro One's business is focused on the transmission and distribution of electricity.

Generation

Generation refers to the production of electricity by a generator. Generators include generating stations (commonly known as power plants) that produce electricity on a large scale, as well as generating equipment that produces electricity on a small scale, such as rooftop solar panels. Small-scale generators installed at or near the end-user's location are sometimes referred to as "distributed generation" sources, which distinguish them from centralized generation sources, which tend to be large scale generators that produce electricity for transportation to other locations. Electricity may be generated using non-renewable fuel sources such as natural gas, coal or nuclear material, or using renewable resources such as water, wind, biomass, solar energy or geothermal heat.

Transmission

Transmission refers to the delivery of electricity over high voltage lines, typically over long distances, from generating stations to local areas and large industrial customers. Transmission customers include distributors of electricity, as well as industrial companies who are directly connected to transmission networks. Transmission also involves the delivery of electricity between different jurisdictions, such as provinces, states or countries. This is accomplished through the use of "interties", which are transmission facilities that physically connect adjacent transmission systems in different jurisdictions. Transmitters own and operate transmission assets such as transmission lines, transformer stations and communications and control facilities.

Distribution

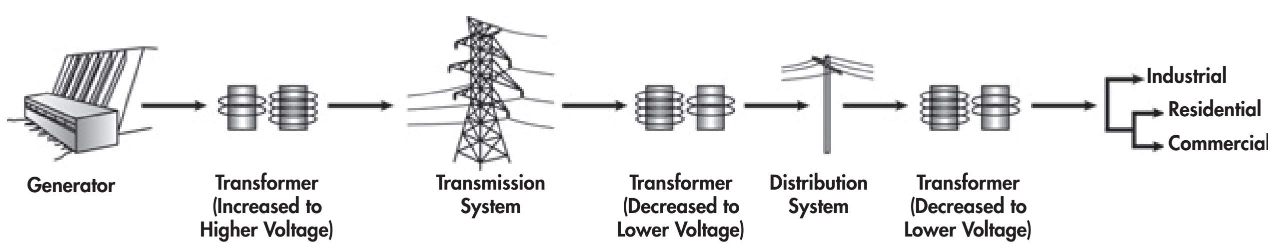
Distribution refers to the delivery of electricity over low voltage power lines to end users such as homes, businesses and institutions. Distributors usually deliver electricity to customers in a particular municipality or geographic area. Distributors may also distribute electricity to other distributors. Distributors own and operate distribution assets such as distribution stations, poles, distribution lines, switches and meters.

Retailing

Retailing refers to the sale of electricity to consumers. In Ontario, retailing of electricity is normally conducted by businesses that do not own the infrastructure or equipment necessary to distribute electricity. Retailers sell electricity to homes and small businesses but rely on distributors to deliver the electricity sold by the retailers. Retailers sometimes also rely on distributors to prepare and deliver electricity bills on behalf of the retailers. Retailers generally offer differentiated products as compared with distributors, such as fixed rate electricity contracts or electricity produced from renewable energy sources. Retailers do not exist in all markets.

Overview of an Electricity System

The basic configuration of a typical electricity system showing electricity generation, transmission and distribution is illustrated in the following diagram:



Transmission and distribution networks are sometimes referred to as the "electricity grid" or simply "the grid". For simplicity, the diagram above does not show customers directly connected to the transmission system or distributed generation sources or other distributors that may be connected to the distribution system.

Canada's Electricity Industry

In Canada, the generation, transmission and distribution of electricity has historically been carried out by government-owned, vertically-integrated utilities. This is still the case in many provinces and territories. However, consistent with general trends in the North American electricity industry, some jurisdictions in Canada, including Ontario, have moved away from this model towards more competitive market structures. In these jurisdictions, vertically-integrated utilities have been reorganized into separate generation, transmission and distribution companies. This separation is intended to promote competition among generators and to facilitate non-discriminatory or "open" access to transmission and distribution systems in order to increase competition in the supply of electricity. As a result, there are some electricity companies in Canada that engage solely in electricity generation, while others engage in either transmission or distribution, or both. Electricity companies in Canada may be investor-owned with shares listed on a stock exchange, or they may be owned by provincial governments, municipal governments or private investors.

The market structure and regulation of the electricity industry has evolved further in some jurisdictions, such as Ontario and Alberta. For instance, in Alberta, generation has been de-regulated, resulting in a competitive market for the generation and sale of electricity. However, all provinces and territories in Canada continue to regulate transmission and distribution rates. This function is carried out by a regulator, which is typically an independent board or commission that oversees and regulates certain aspects of the electricity industry in each province and territory.

The demand for electricity in Canada is affected by many factors, including population growth, economic growth and the electricity needs of households and businesses. The demand for electricity varies continuously. Electricity demand is typically seasonal, rising with the increased use of air conditioning in the summer or electric heating in the winter. Increased electricity usage over the medium to long term generally results in additional investments that are required to be made by generation, transmission and distribution businesses.

The provinces of Ontario, Québec, British Columbia and Alberta are the largest consumers of electricity in Canada. According to the National Energy Board, electricity demand in Canada is expected to grow at an annual rate of 1% from 2013 until 2035, with most of the demand originating from the industrial sector. In recent years, Canada has been a net exporter of electricity to the United States.

Electricity is generated in Canada using a variety of non-renewable and renewable sources. Hydroelectric generation accounts for most of the electricity produced in Canada on an overall basis. Fossil fuels, such as coal, natural gas and oil, are the second most common source of electricity generation, followed by nuclear power. The actual mix of generation varies in each province and territory based on the type of generation sources available. For instance, hydroelectric power is common in provinces such as Québec, Ontario, Manitoba and British Columbia because of the availability of water resources suitable for electricity production, while coal-fired generation is common in Alberta and Saskatchewan in part because of the large coal deposits that exist in those provinces. Nuclear power is a significant source of generation in Ontario. Electricity generation from renewable sources has increased in recent years and is expected to increase further in Canada over the long term, while generation from coal and oil are expected to decrease.

The transmission system in Canada includes more than 160,000 kilometres of transmission lines. Generators, transmitters, distributors and system operators must work to ensure that enough electricity and transmission and distribution capacity is available to meet demand at any given time and avoid power outages. Adequate transmission capacity and well-maintained transmission and distribution networks are key elements of a reliable electricity grid.

Ontario's Electricity Industry

Evolution

The structure of Ontario's electricity industry underwent significant change in the late 1990s and early 2000s. Prior to April 1, 1999, Ontario Hydro, a Crown corporation owned by the Province, supplied most of Ontario's needs with respect to electricity generation, transmission and distribution. Consistent with initiatives taken in other electricity markets in North America at the time, the Province initiated a restructuring of the electricity industry in Ontario in order to encourage greater competition. The adoption of the *Electricity Act, 1998* (Ontario) (the "**Electricity Act**") resulted in the reorganization of Ontario Hydro into five separate entities, including Hydro One Inc., as the successor to its transmission and distribution business, and Ontario Power Generation Inc., as the successor to its generation business. Each of Hydro One Inc. and Ontario Power Generation Inc. is currently 100% owned by the Province.

The Electricity Act also established the requirement of transmitters and distributors to provide non-discriminatory or "open" access to their transmission and distribution systems in order to facilitate greater competition in the supply of electricity.

As part of the restructuring of Ontario's electricity industry, the province's municipally-owned electricity distributors were reorganized into separate business corporations. These distributors are typically referred to in Ontario as local distribution companies, or "**LDCs**". Many of these distributors were sold by their municipal owners, who benefitted from limited exemptions from the transfer tax that applies to certain transfers that they would otherwise have had to pay on the fair market value of the utility. This led initially to a significant reduction in the number of local distribution companies in Ontario, with Hydro One Inc. as the primary consolidator. Consolidation activity involving local distribution companies has since slowed.

Other major regulatory developments affecting Ontario's electricity industry that have occurred since the 1990s include:

- the expansion of the mandate of the Ontario Energy Board to regulate the electricity industry, in addition to the natural gas industry, in Ontario,
- the creation of the Independent Electricity System Operator ("**IESO**") to manage the operation and reliability of Ontario's bulk power system and administer the wholesale electricity market;
- the creation of the Ontario Power Authority in 2004 (recently merged with the IESO in 2015) to engage in conservation initiatives, generation development and power system planning,
- the promotion of renewable energy production in Ontario, including through Ontario's Feed-in Tariff programs which followed the adoption of the *Green Energy and Green Economy Act, 2009* (Ontario),
- since 2010, the issuance by the Province every three years of a Long-Term Energy Plan (most recently in 2013) to serve as a planning document to guide future energy decisions in Ontario,
- the promotion of energy conservation measures, including through mandatory conservation and demand management requirements that must be followed by distributors, and
- the retirement of coal-fired generation in Ontario, which was completed in 2014.

Premier's Advisory Council on Government Assets

In April 2014, the Province formed the Premier's Advisory Council on Government Assets (the "**Council**"). The mandate of the Council was to review certain provincially-owned assets, including Ontario Power Generation Inc. and Hydro One Inc., and to recommend ways to maximize their value to the people of Ontario. In its final electricity sector report released in April 2015, the Council recommended, among other things, that the Province should proceed with a partial sale of its interest in Hydro One Inc. to create a growth-oriented company centred in Ontario. The Council recommended that the partial sale occur by way of a public offering, with approximately 15% of the shares of Hydro One Inc. to be offered to the market initially. The Council recommended that the Province indicate its intention to retain its remaining shares after selling down to 40% ownership, and that the balance should be widely held with no other individual shareholder having more than a 10% holding. The Council separately recommended proceeding with a sale or merger of the Province's interest in Hydro One Brampton Networks Inc. to or with other local distribution companies in Ontario in order to act as a catalyst for consolidation and to strengthen competition in the electricity distribution sector.

In response to the Council's recommendations, the Province is proceeding with this offering to broaden the ownership of Hydro One Inc. indirectly through its sale of shares in Hydro One Limited. The Province also announced that it would proceed with the sale or merger of Hydro One Brampton Networks Inc. In anticipation of that transaction, on August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions.

Regulation of Transmission and Distribution

General

The Electricity Act and the *Ontario Energy Board Act, 1998* (the "**Ontario Energy Board Act**") together establish the general legislative framework for Ontario's electricity market. The activities of transmitters and distributors in Ontario are overseen by three main regulatory authorities: (i) the Ontario Energy Board, (ii) the IESO, and (iii) the National Energy Board.

Ontario Energy Board

The Ontario Energy Board was established in 1960 and is the regulator of natural gas and electric utilities in Ontario. The Ontario Energy Board is an independent and impartial public regulatory agency. Its mandate changed significantly with the restructuring of the electricity market in Ontario in the late 1990s, when it became responsible for regulating local electricity distribution companies and for ensuring that distributors fulfill their obligations to connect and serve their customers. The Ontario Energy Board also became responsible for licensing certain participants in the electricity market, including transmitters and distributors. The Ontario Energy Board Act provides the Ontario Energy Board with the authority to regulate Ontario's electricity market, including the activities of transmitters and distributors.

The Ontario Energy Board has the following objectives in relation to the electricity industry:

- to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service,
- to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry,
- to promote electricity conservation and demand management in a manner consistent with the policies of the Province, including having regard to the consumer's economic circumstances,
- to facilitate the implementation of a smart grid in Ontario, and
- to promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Province, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The Ontario Energy Board is responsible for, among other things, approving transmission and distribution rates in Ontario. It also approves the construction, expansion, or reinforcement of transmission lines greater than two kilometres in length, as well as mergers, acquisitions, amalgamations and divestitures involving distributors and other entities which it licenses. The activities of transmitters and distributors are subject to the conditions of their licenses and a number of industry codes issued by the Ontario Energy Board. These codes and other requirements prescribe minimum standards of conduct and service for licensed participants in the electricity market.

Bill 112 was introduced in the Legislative Assembly of Ontario in June 2015. The Bill, as proposed, would amend the Ontario Energy Board Act to enhance the Ontario Energy Board's authority to continue to protect electricity ratepayers with respect to retailer contracts, as well as enhance consumer protection and reliability. These changes, if enacted, would provide the Ontario Energy Board with: stronger compliance and enforcement powers by increasing penalties for companies that are not complying with its rules and directions; enhanced ability to ensure reliability and continuity of service if distribution or transmission companies are unable to fulfil their license obligations; enhanced oversight for ensuring best practices regarding utility consolidation activities; and stricter oversight of retailers as well as more protection for consumers who sign energy retail contracts.

IESO

The IESO is a not-for-profit corporation established in 1998 under the Electricity Act. It was created to manage the operation and reliability of Ontario's bulk power system and administer the wholesale electricity market that was created with the restructuring of Ontario's electricity industry in the late 1990s. It is governed by an independent board whose chair and directors are appointed by the Province. Today, the IESO oversees the wholesale electricity market and directs the real time operation of the power system by balancing the supply and demand of electricity in Ontario and directing the flow of electricity across transmission lines.

Transmitters and other wholesale market participants, which include many distributors, must comply with the Market Rules issued by the IESO. The Market Rules establish a number of requirements that affect transmitters, including the requirement to comply with mandatory North American reliability standards for transmission issued by the North American Electric Reliability Corporation ("**NERC**") and the Northeast Power Coordinating Council, Inc. ("**NPCC**"). These reliability standards became mandatory as a result of regulatory changes following the Northeast blackout that occurred in 2003. The IESO enforces these reliability standards through its Market Assessment and Compliance Division and also coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity system in North America.

In 2015, the IESO merged with the Ontario Power Authority and assumed responsibility for integrated medium and long-term power system planning in Ontario, including the planning of electricity needs and the procurement of clean sources of electricity supply. These activities include identifying the need for new transmission capacity. The IESO also coordinates province-wide conservation efforts, including approval of mandatory conservation and demand management programs for distributors.

National Energy Board

The National Energy Board is an independent federal regulatory agency that was established in 1959 with the mandate to regulate aspects of the Canadian energy industry under federal jurisdiction, and to inform the government and public about energy matters. The National Energy Board is governed by the *National Energy Board Act* (Canada) and has jurisdiction over the construction and operation of international power lines, as well as interprovincial lines that are designated as being under federal jurisdiction (of which there are currently none). As Hydro One owns and operates 11 active international power lines connecting Ontario's transmission system with transmission systems in Michigan, Minnesota and New York, Hydro One is required to hold several certificates and permits issued by the National Energy Board, and is subject to its mandatory electricity reliability standards and reporting requirements.

Generation

In Ontario, electricity generation is supplied by a number of providers, with Ontario Power Generation Inc. producing approximately half of the electricity produced in Ontario. Its generation is largely rate-regulated, with rates approved by the Ontario Energy Board. The remainder of Ontario's electricity is produced by non-government-owned producers. These producers generally sell their electricity pursuant to long-term power purchase agreements entered into with the IESO.

According to the IESO, the total installed generation capacity in Ontario was 35,163 MW as of September 21, 2015, of which 37% was supplied by nuclear facilities, 28% by gas or oil-fired facilities, 24% by hydroelectric facilities, 9% by wind-powered facilities and 1% by biofuel facilities. In its most recent Long-Term Energy Plan issued in 2013, the Province indicated that it is targeting to have a total of 20,000 MW of renewable generation on-line by 2025, which is forecast to represent approximately half of Ontario's generation capacity.

Transmission

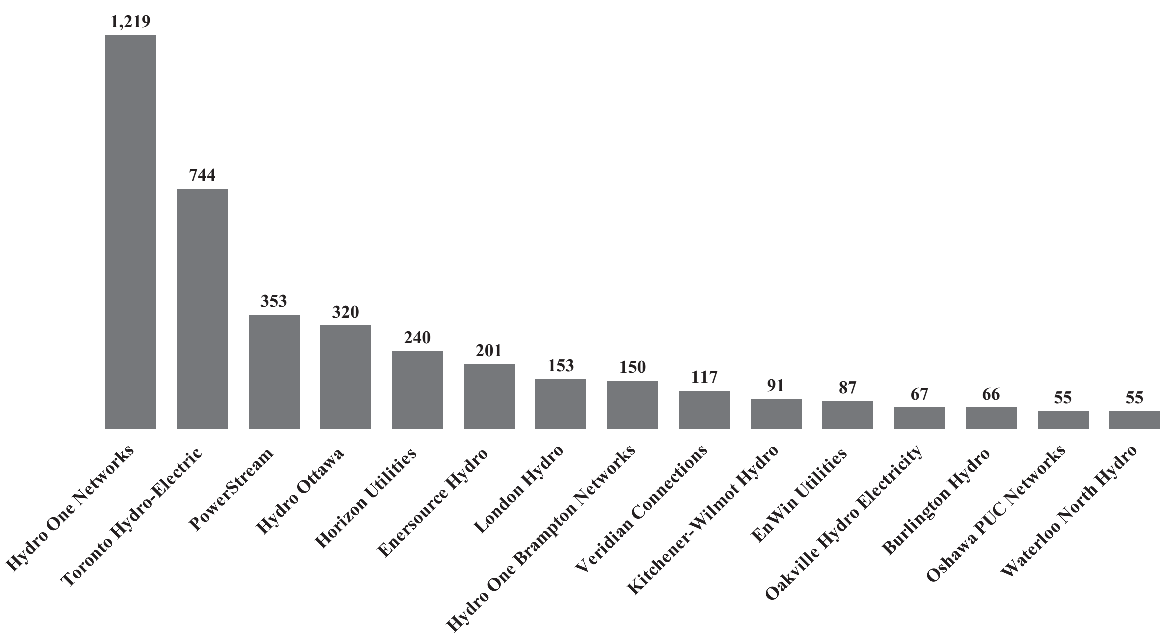
Transmission companies own and operate transmission systems that deliver electricity over high voltage lines. Hydro One's transmission system accounts for 96% of Ontario's electricity transmission network. The Company's transmission system is interconnected to systems in Manitoba, Michigan, Minnesota, New York and Québec and is part of the larger North American system known as the Eastern Interconnection. The Eastern Interconnection is a contiguous electricity transmission system that extends from Manitoba to Florida and from east of the Rocky Mountains to the North American east coast. Being part of the Eastern Interconnection provides benefits to Ontario, such as greater security and stability for Ontario's transmission system, emergency support when there are generation constraints or shortages in Ontario, and the ability to exchange electricity with other jurisdictions, which facilitates a more competitive marketplace.

Investments in transmission infrastructure are required to ensure the safe and reliable delivery of electricity. These investments are made to maintain the function and reliability of transmission systems, accommodate increased demand for electricity and respond to developments affecting the electricity industry. Developments with respect to electricity generation often have a direct impact on transmitters, since significant investments in transmission systems may be required to accommodate new generation sources (such as renewable energy) or the retirement of existing generation facilities (such as coal-fired facilities). For instance, as coal-fired generation in Ontario was retired, significant transmission investments were required to accommodate the subsequent changes in electricity flows across the transmission system. Similarly, Hydro One is currently constructing a major transformer station (the Clarington transformer station) in order to accommodate changes to the transmission system arising from the eventual retirement of the Pickering nuclear generation facility. Major changes affecting the generation of electricity must be closely coordinated with transmission considerations in mind. Recent discussions and initiatives by provincial governments to examine opportunities for Ontario to import additional electricity from Québec and Newfoundland and Labrador may also require new transmission infrastructure. These types of investments are in addition to the investments that transmission companies must undertake to sustain their existing assets, maintain reliability, and provide connections to the transmission system.

Distribution

Distributors own and operate distribution systems that deliver electricity over low voltage power lines to end users. In Ontario, 72 local distribution companies currently provide electricity to approximately five million customers. The distribution industry in Ontario is fragmented, with the 15 largest local distribution companies accounting for approximately 78% of the province's five million customers. Hydro One owns the largest local distribution company in Ontario, Hydro One Networks Inc., with approximately 1.3 million customers, or approximately 25% of the total number of customers in Ontario.

15 Largest Distributors in Ontario(1)
(Thousands of Customers)



Notes:

(1) Source: *Ontario Energy Board Yearbook of Distributors* (2014). For Hydro One Networks Inc., the 1,219 figure excludes certain classes of customers which are included in the total number of customers reported elsewhere in this prospectus.

(2) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc.

Most of the local distribution companies in Ontario are owned or jointly owned by municipalities. A local distribution company is responsible for distributing electricity to customers in its Ontario Energy Board-licensed service territory, and in some cases to other distributors. A service territory may cover large portions or all of a particular municipality, or an otherwise-defined geographic area. Some municipalities in Ontario are served by more than one local distribution company, each covering a particular area of the municipality. Distribution customers include homes, businesses and institutions such as governments, schools and hospitals.

To create more efficiency in the distribution sector, the Council has endorsed the need for faster consolidation among local distribution companies in Ontario. The Council also noted that the system needs private sector capital and a level of competition that will encourage innovation among companies that can adjust nimbly to the changing energy world. In addition, the Council has recommended time-limited tax incentives to promote consolidation. These tax incentives were included in the 2015 Ontario Budget, which announced a reduction in the transfer tax rate from 33% to 22%, an exemption from transfer tax for distributors with fewer than 30,000 customers and an exemption from the capital gains portion of the departure tax. These changes, which are intended to promote consolidation, would apply for the period beginning January 1, 2016 and ending December 31, 2018.

Electricity Industry in the United States

The general structure of the electricity industry in the United States is similar to that in Canada, particularly with respect to the regulation of transmission and distribution. Although the regulatory framework varies on a state-by-state basis, electricity transmitters and distributors generally operate under a regulated cost of service model.

In the United States, electric utilities range from fully integrated utilities to pure-play utilities which focus solely on transmission or distribution. There is a wide range of utility owners in the United States, including strategic and financial investors, both domestic and international, as well as governments and municipalities. The term "investor owned utility" is used in the United States to refer to electric and other utilities that are not government owned. The number of investor owned utilities has declined significantly as a result of consolidation – from 98 in 1995 to 47 in 2014. In recent years, investor owned utilities have followed a trend of migrating back toward a traditional regulated structure which has occurred as a result of a combination of organic growth in rate base, the acquisitions of regulated businesses and divestiture of non-regulated businesses. According to Bloomberg, mergers and acquisition activity in the North American power and utilities sector has been active in recent years, with 351 transactions announced since 2014. The total value of transactions with a disclosed acquisition price was $132.5 billion.

The U.S. electric transmission grid consists of more than 320,000 kilometres of high-voltage lines. The transmission system is regulated by the Federal Energy Regulatory Commission, which governs the planning and investment of transmission infrastructure, including setting a utility's return on equity. Reliability standards for transmission are issued by the NERC and regional reliability councils such as the NPCC.

Recent years have seen significant transmission investment. According to the Edison Electric Institute, investor-owned electric utilities made transmission investments of approximately U.S.$16.9 billion in 2013. An additional U.S.$60.6 billion in transmission investments are expected to be necessary to modernize the transmission system through 2024. Investment in transmission is currently significantly higher than in previous years, with the largest component related to transmission expansion or new line development to ease congestion, interconnection of new sources of generation, including renewables, and support for production of shale gas. Investment is also required for improved system reliability and resiliency as well as replacement of existing lines.

The electricity distribution industry in the United States is generally subject to regulation by the state public utility commission in the jurisdiction in which the utility operates, which leads to significant variations in the allowable return on equity and other components of the rate setting process. Investment in electric distribution infrastructure by investor owned utilities in 2013 totaled U.S.$20.8 billion. Investment in the electricity distribution sector is primarily driven by the ongoing need to replace assets that have outlived their life cycle, to serve new loads or demand, to preserve reliability, to improve system security, resiliency and restoration capabilities, and increasingly in recent years, to accommodate growth in distributed generation.

Certain Trends in the Electricity Industry

Opportunities for Sector Consolidation

A number of regulated utilities have pursued acquisitions outside of their home jurisdictions to seek growth and diversification opportunities. The rationale for this strategy is to increase their scale and scope and diversify their asset base. Many electric utilities have also acquired regulated utilities outside of the electricity sector, such as gas distribution or water distribution. In addition to the potential for increased scale, scope and diversification, this strategy offers the potential to create synergies within given service territories from a regulatory and operations perspective.

Consolidation trends have been evident in Europe and in the United States, but have not been prevalent in Canada given its limited number of privately-owned utilities. Pension and infrastructure funds have also been active participants in acquisitions in the utilities sector.

Impact of Green Energy Initiatives

Environmental regulations are being adopted in many jurisdictions in order to facilitate the development of cleaner forms of energy. Many governments and regulators are setting targets with specified compliance dates to meet green energy standards. These may take the form of targets for the reduction of carbon dioxide emissions or the procurement of renewable generation. These initiatives may result in changes to the electricity generation mix in those jurisdictions, potentially creating the need for upgrades to transmission infrastructure in order to preserve the reliability of the electricity grid. For example, as coal-fired generation was retired in Ontario, significant investments were required to accommodate the subsequent changes in power flows across the transmission system.

In August 2015, the Environmental Protection Agency in the United States announced the final version of what is commonly known as the Clean Power Plan, a series of regulatory changes that would, among other things, impose significant emissions restrictions on electric generation facilities. The final version of the plan sets a goal of reducing emissions from power plants by 32% by the year 2030, as compared with 2005 levels. These emissions restrictions are particularly aimed at coal-fired generation facilities. In a preliminary assessment of the reliability impacts in meeting this plan in North America, the NERC noted the potential opportunity for coordinated cross-border transmission flows, including the increased potential for Canadian companies to export up to three times more power to the United States. This may provide additional opportunities for renewable generation development in Ontario. Regulators, system planners and other parties are in the process of assessing the impact of the Clean Power Plan and increased intertie capacity to the United States.

Developments with Respect to Distributed Generation, Microgrids and Energy Storage

Alternatives to the traditional model of “centralized” generation are continually being developed. For instance, distributed generation sources, such as rooftop solar panels or natural gas generators integrated into industrial facilities, are becoming increasingly common. Where distributed generation sources are connected to the electricity grid, they may act as a source of supply to the grid, or reduce the amount of power supplied from the grid, while still making use of the grid as a stand-by source of power. Related to distributed generation are microgrids, which are small scale electricity grids with their own sources of generation that can operate independently of the electricity grid.

Energy storage technologies seek to store energy for use at a later time. Historically, there have been technical limitations on the ability to store large amounts of electricity. For this reason, electricity systems are designed to generate more electricity than is required in order to meet anticipated peak demand, which creates inefficiencies. The development of larger and more effective energy storage technologies could provide an additional means to facilitate the reliability of the electricity grid by acting as a source of back-up power, which would allow generators to produce less electricity in order to meet anticipated peak demand. Energy storage technologies may also facilitate improvements to power quality by smoothing fluctuations in power demand and enhance reliability by easing points of congestion in transmission and distribution networks.

These developments represent an opportunity to employ new technologies to improve reliability and power quality, or provide an alternative to constructing or maintaining traditional “wires” infrastructure. For instance, microgrids could be used in remote or other locations where it is not cost-effective to build transmission and distribution networks to serve customers in those locations.

Smart Meter and Smart Grid Technologies

The increasing adoption of energy conservation measures together with initiatives to reduce emissions from the generation of electricity has led to the development of technologies such as smart meters, which, unlike traditional electricity meters, provide customers with information about their electricity usage to enable them to change their consumption patterns and reduce their costs. Smart grids are an extension of this concept, and generally refer to a combination of technologies, such as computer systems, two-way communications technologies and monitoring systems aimed at improving the reliability and performance of the electricity grid and at expanding opportunities to provide demand response, price information and ability to control usage to electricity customers. For example, in the event of a power interruption, smart grid technology can be used to more quickly detect and locate the source of the interruption and restore service by re-routing electricity to alternative supply lines and generation sources. Smart grids are at varying stages of development and usage. One of the objectives of the Ontario Energy Board is to facilitate the implementation of a smart grid in Ontario.

Competitive Processes for Developing Transmission Infrastructure

Consistent with the general trend seen in government procurement programs for infrastructure investments, governments and electricity sector regulators are increasingly using competitive bidding processes to select the applicant to develop new large transmission projects. For instance, in Ontario, the Ontario Energy Board used a competitive process to select the designated transmitter for the development phase of the proposed East-West Tie Line, which would be a transmission line running between Thunder Bay and Wawa, Ontario. In Alberta, the Alberta Electric System Operator conducted a similar process to award the agreement for the Fort-McMurray West Transmission Project.

Incumbent transmission companies may experience increased competition from other utilities, construction companies and private investors in the competitive bidding processes for new transmission projects and are using a greater range of strategies to bid for the development and construction of new transmission infrastructure. These include forming consortiums, alliances and joint ventures, such as those with First Nations and Métis communities, and adopting cost and revenue sharing arrangements to share project risk. Larger and more established electric utilities may be well-positioned to enter into these arrangements due to their experience, expertise and effectiveness in engaging with stakeholders, and their existing infrastructure and transmission corridors.

RATE-REGULATED UTILITIES

Overview

The rates charged for electricity transmission and distribution services are regulated in Canada and many other jurisdictions. The term “rate-regulated” is used to refer to an electricity business whose rates for transmission, distribution or other services are subject to approval by a regulator. The Ontario Energy Board is the regulator responsible for approving electricity transmission and distribution rates in Ontario.

In Canada, regulators generally use two different models for approving the rates charged by rate-regulated utilities: (i) a “cost of service” model, and (ii) a “performance-based” model (sometimes also referred to as an “incentive-based” model).

In a cost of service model, a utility charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. The costs of providing its services must be prudently-incurred. Cost savings are typically passed on to customers in the form of lower rates reflected in future rate decisions. In a cost of service model, the utility has the potential to retain cost savings that are achieved in the intervening years between rate decisions.

In a performance-based model, a utility also charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. However, the rates charged by the utility in a performance-based model assume that the utility becomes increasingly efficient over time, resulting in lower costs to provide the same service. If a utility achieves cost savings in excess of those established by the regulator, the utility may retain some or all of the benefits of those cost savings, which may permit the utility to earn more than its allowed return on equity.

Value Drivers for a Rate-Regulated Utility

Management believes that the key drivers of value for a rate-regulated utility are:

- the utility’s rate base,
- the utility’s deemed capital structure, as set by the regulator,
- the utility’s allowed return on equity, as set by the regulator,
- capital expenditures that ultimately add to the utility’s rate base,
- the ability to generate efficiencies and cost savings in the operations of the utility, and
- the ability to maintain a constructive relationship with its regulator.

Rate Base

The rate base of a rate-regulated utility refers to the net book value of the utility’s assets for regulatory purposes. Rate base is an important regulatory term because a utility is permitted to earn a return on the equity portion of its rate base. An increase in a utility’s rate base will generally result in an increase in the utility’s net income, all other things being equal.

Rate base differs from a utility’s total assets for accounting purposes, primarily because it only includes the regulated assets of a utility. If a utility also owns and operates non-rate-regulated businesses, the assets of those businesses are not included in the utility’s rate base. A utility’s rate base must be calculated in accordance with the requirements of the utility’s regulator and must be approved by the regulator as part of the utility’s application for transmission or distribution rates. In Ontario, the rate base for a transmission or distribution company generally includes the gross value of the company’s regulated assets (such as transmission lines and transformers or distribution lines and poles), less accumulated depreciation, and adding an allowance for working capital. The rate base of a utility is reduced by ongoing depreciation of the utility’s regulated assets.

Capital Structure

Rate-regulated utilities have a “deemed” or approved capital structure that is set by the regulator. This is typically expressed as ratio of debt-to-equity. In Ontario, the deemed capital structure for electricity transmitters and distributors set by the Ontario Energy Board is 60/40. This means that a utility is considered to have a capital structure consisting of 60% debt and 40% equity. This capital structure is applied to the utility's rate base. For instance, if a utility has a rate base of $100 million and a 60/40 capital structure, this means that the regulated assets of the utility are deemed to be capitalized with $60 million of debt and $40 million of equity. The deemed capital structure is important to a utility because it is used to calculate the dollar amount of a utility's return on equity that the utility is entitled to be paid through rates. See "– Return on Equity" below. A utility's deemed capital structure also reflects the regulator's view of the amount of debt that a utility should have in order to operate prudently.

Return on Equity

A utility's return on equity or "ROE" is the rate of return that a regulator allows the utility to earn on the equity portion of the utility's rate base. Return on equity is expressed as a percentage. For instance, over the past six years, Hydro One's allowed return on equity approved by the Ontario Energy Board has ranged from 8.39% to 9.66% for its transmission business and 9.30% to 9.85% for its distribution business.

A utility's return on equity represents the amount, over and above a utility's costs associated with providing services, that a utility is permitted to earn as its net income after tax. A utility's allowed return on equity is therefore a significant factor that affects the financial performance of rate-regulated utilities.

In order to calculate its allowed return on equity as a dollar amount, the utility applies the allowable return on equity percentage set by the regulator to the equity portion of its rate base. The equity portion of its rate base is, in turn, determined by multiplying the utility's rate base by the percentage of equity reflected in its deemed capital structure (i.e., 40% in Ontario).

Regulators use different methods to set a utility's allowed return on equity, and these methods vary from jurisdiction to jurisdiction. In Ontario, the Ontario Energy Board sets the allowed return on equity for transmission and distribution companies. In doing so, it sets a percentage, and adjusts this percentage by applying a formula that takes into account the interest rates on certain government debt securities and a risk premium based on utility bond spreads. The allowed return on equity is reviewed and changed by the Ontario Energy Board annually.

Capital Expenditures

Transmission and distribution companies incur capital expenditures to allow them to meet their obligations to deliver electricity safely and reliably, at a reasonable cost to customers. Utilities incur both sustaining capital expenditures, which maintain the performance of existing assets, and development capital expenditures, which add to or expand existing assets. Development capital expenditures include those investments required to develop and build large-scale projects such as new transmission lines and stations as well as smaller projects such as transmission line or station reinforcements, extensions or additions. Capital expenditures tend to increase a utility's rate base after the assets produced by the capital expenditures become operational (sometimes referred to as "in-service") and are approved by the regulator for inclusion in the utility's rate base. Capital expenditures are therefore a key driver of value for a rate-regulated utility.

Operational Cost Savings and Efficiencies

Utilities seek greater efficiency and cost savings, including from economies of scale, productivity improvements or the use of new technology and systems. These cost savings are typically passed on to customers in the form of lower rates. In a cost of service model for rates, this means that the lower costs may be reflected in a lower revenue requirement approved by the regulator in the utility's next rate application, while the utility has the potential to retain cost savings that are achieved in the intervening years between rate decisions. In other words, in a cost of service model, cost savings, if any, are generally only retained by the utility until new rates are approved by the regulator. In a performance-based model for rates, the utility has the potential to retain some or all of the benefit of cost savings achieved in excess of those established by the regulator, thereby increasing its return on equity. The ability to demonstrate greater efficiency and cost savings in the operations of a utility is a key factor in a regulator's decision to approve rates. This, together with the utility's desire to increase profitability while keeping rates low, provides incentives for utilities to continue to seek more efficient ways to deliver their service to customers.

Relationship with Regulator

The ability of a utility to maintain a constructive relationship with its regulator is a key driver of value. This relationship lays the foundation for all decisions made by the regulator in respect of the utility's business, including with respect to revenue requirements. The term "revenue requirement" refers to the amount that a utility is entitled to charge through rates that covers its cost of providing services plus the dollar amount of its allowed return on equity. A utility must justify and provide supporting evidence for its performance and forecasted cost of service. A rate-regulated utility seeks to obtain approval from its regulator for its revenue requirement in a manner that covers the actual costs of providing services and generates an adequate return on equity. To the extent that the utility earns any ancillary revenues from its regulated assets or personnel, these are subtracted from the revenue requirement.

Rate Applications in Ontario

Framework

The Ontario Energy Board is the regulator that approves electricity transmission and distribution rates in Ontario. Transmission rates are currently determined based on a cost of service model, while distribution rates are generally determined using a performance-based model. These models are reviewed and modified by the Ontario Energy Board from time to time. The Ontario Energy Board has indicated that it will provide guidance regarding how the policies in its performance-based framework for distribution rates may be applied to transmitters in the future.

Transmission Rates (Cost of Service Model)

In the current model for determining transmission rates in Ontario, a transmitter applies to the Ontario Energy Board for approval of its revenue requirement for each year covered by its rate application (typically two years in total). The revenue requirement for each year covers the anticipated costs of providing the service for that year and an amount that represents the allowable return on equity approved by the Ontario Energy Board.

Cost of Service ($)	+	**Return on Equity ($)**	=	**Revenue Requirement ($)**

For example, if a utility is applying for the approval of rates for 2017 and 2018, it may request a revenue requirement of $1,000 million for 2017 and $1,050 million for 2018. The cost of service would generally consist of: (i) income taxes (or payments in lieu of taxes), (ii) the utility's cost of debt, (iii) depreciation on the utility's assets, and (iv) operation, maintenance and administration costs.

The following diagram illustrates the components of a hypothetical transmitter's revenue requirement of $1,000 million for a particular year.

Return on Equity	$200 million	Calculated by multiplying the allowed return on equity set by the regulator by the equity component of the utility's rate base
Income Taxes	$50 million	Taxes or payments in lieu of taxes
Cost of Debt	$150 million	The approved cost of debt for the utility at the deemed capital structure
Depreciation	$300 million	Depreciation and amortization on transmission assets such as towers, stations and components
Operation, Maintenance and Administration Costs	$300 million	Labour, materials, equipment and other costs to operate and maintain the utility's transmission system
Revenue Requirement	$1,000 million	

In the example above, $800 million of the transmitter's revenue requirement is to cover the transmitter's anticipated cost of service for that year. The $200 million amount represents the allowed net after tax return on equity over and above the transmitter's cost of service.

Distribution Rates (Performance-Based Model)

In the current model for determining distribution rates in Ontario, a utility applies to the Ontario Energy Board to have its cost of service reviewed as part of its application for distribution rates. However, the process for applying for distribution revenue requirements differs from the process for applying for transmission revenue requirements in the following ways:

- the period covered by a distribution rate application is typically at least five years, which is longer than the typical period covered by a transmission rate application,
- the utility applies for the approval of its revenue requirement only for the first year covered by the rate decision,
- the revenue requirement for each of the subsequent years is determined based on a formula that accounts for inflation and certain productivity factors set by the regulator. The revenue requirement in these subsequent years is set on the assumption that the utility is lowering its cost of service over the period covered by the rate decision due to efficiency or productivity improvements,
- the utility is permitted to retain all or a portion of the cost savings achieved in excess of those established by the regulator during the period covered by the rate decision, thereby allowing the utility to earn more than its allowed return on equity, and
- the utility and the Ontario Energy Board must, as part of the application process, agree on a set of performance measures that the utility must meet and on which it must report on an ongoing basis to the Ontario Energy Board. These are intended to reduce the incentive of utilities to allow service or performance levels to deteriorate as the utilities lower their cost of service.

Under a performance-based model, the utility must effectively manage its business to earn its allowed return on equity over the period covered by the rate decision. Under this model, revenues earned from rates may not correspond to the utility's actual costs.

Application Process

Transmitters and distributors must file a rate application with the Ontario Energy Board to seek approval of their revenue requirement, which forms the basis for the rates to be charged for the approved period. Hydro One typically files a rate application every two years for transmission rates, which are applicable for the prospective two year period. The period between its applications for distribution rates tends to be more variable, and depends on the type of application selected by Hydro One for distribution rates.

A rate application is supported by pre-filed evidence, which contains details on the various categories of expenses proposed to be incurred by the transmitter or distributor, including operations, maintenance and administration costs, depreciation and amortization, costs of debt and income taxes (or payments in lieu of taxes). A rate application will also include details on the capital expenditures proposed to be made based on available information and assumptions made at the time of the rate application. It is generally expected that a utility would exercise discretion in selecting, prioritizing and adjusting the timing of capital projects. This can result in deviations from the projects listed in the rate application. A utility must demonstrate to the Ontario Energy Board that capital investments were appropriate and prudent for inclusion in the utility's rate base, which must be approved by the Ontario Energy Board. The rates paid to the utility are based on the rate base, which is periodically adjusted by the Ontario Energy Board to reflect assets that are placed into service.

Intervenors, such as consumer groups and other electricity industry participants, and staff of the Ontario Energy Board, may also participate in the applicant's stakeholder activities, in technical conferences, and in the tribunal process itself, and they may also file questions and their own evidence. The parties may attempt to negotiate a full or partial settlement of the issues raised by the application. Unsettled issues are referred to a hearing, in which the applicant is required to defend its rate application through a written or oral hearing. After the completion of the hearing, the Ontario Energy Board issues a decision with reasons. In the case of rate proceedings, the applicant must submit a draft rate order reflecting the decision of the Ontario Energy Board. The Ontario Energy Board will approve the final rate order or request revisions to better reflect its decision.

Transmitters and distributors such as Hydro One must forecast and make assumptions regarding their expected costs and the demand for electricity during the periods covered by the rate application, and they must support their applications with information about prior or historical years and the current year. In Ontario, rate applications use "forward test years", rather than historical test years, which means that rates are set based on forecasts and projections of electricity demand and costs of service in the years covered by the rate decision, rather than based on historical electricity demand and cost information, which may not accurately reflect actual future electricity demand and costs.

A transmitter or distributor may apply to the Ontario Energy Board during the period between rate decisions for the approval of "deferral accounts" or "variance accounts", which are accounts used by the utility to record amounts due to, or amounts to be received from, rate payers at a future date, generally in conjunction with a rate decision from the Ontario Energy Board. For instance, these accounts may be used to track, among other items, unforeseen capital expenditures or particular operation, maintenance and administration costs incurred during that period that were not included in the utility's last application for rates. The Ontario Energy Board will determine in connection with a subsequent rate application whether to allow a utility to include the assets produced from these capital expenditures in the utility's rate base or to recover such costs in rates.

Once distribution rates are approved, the Ontario Energy Board has the right to revisit distribution rates in cases where the utility's actual earnings are above or below 300 basis points of its allowed return on equity or if performance erodes to unacceptable levels.

BUSINESS OF HYDRO ONE

Business Segments

Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario by number of customers.

Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business (telecommunications).

Hydro One's transmission business consists of owning, operating and maintaining Hydro One's transmission system, which accounts for 96% of Ontario's transmission network. This includes the Company's 66% interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. Hydro One's transmission business represented approximately 56% of its total assets as at June 30, 2015, and accounted for approximately 72% of its total net income in 2014. All of the Company's transmission business is carried out by its wholly-owned subsidiary, Hydro One Networks Inc., except for the portion of its business held through B2M Limited Partnership, which the Company controls.

Hydro One's distribution business consists of owning, operating and maintaining Hydro One's distribution system, which it owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. The Company's distribution system is also the largest in Ontario, and principally serves rural communities. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the Ontario Energy Board. Hydro One's distribution business represented approximately 42% of its total assets as at June 30, 2015, and accounted for approximately 28% of its total net income in 2014. Hydro One's distribution business also includes the business of its wholly-owned subsidiary, Hydro One Remote Communities Inc., which operates on a cost-recovery basis and supplies electricity to customers in remote communities in northern Ontario.

Hydro One's transmission and distribution businesses are both operated through Hydro One Networks Inc. This allows both businesses to utilize common operating platforms, technology, work processes, equipment and field staff and thereby take advantage of operating efficiencies and synergies. For regulatory purposes, Hydro One Networks Inc. files separate rate applications with the Ontario Energy Board for each of its licensed transmission and distribution businesses.

Hydro One's other business segment principally consists of its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, and also markets and sells fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements. Hydro One's other business segment is not rate-regulated. This segment represented approximately 2% of Hydro One's total assets as at June 30, 2015, and accounted for less than 1% of its total net income in 2014. The telecommunications business is carried out by the Company's wholly-owned subsidiary, Hydro One Telecom Inc.

Upon completion of this offering, Hydro One Limited will be one of Canada's largest publicly-listed electricity companies, measured by assets. With a stable regulated business, strong "A" category credit ratings and projected increases in its rate base, Hydro One expects to continue generating stable and growing net cash from operating activities to fund its ongoing sustaining capital investments and to support a strong and growing dividend. The Company will operate independently of the Province and will be overseen by an experienced and independent board of directors.

Investment Highlights

Stable Regulated Cash Flows and Strong Balance Sheet

The transmission and distribution of electricity are essential infrastructure services. Hydro One's transmission and distribution businesses are fully rate-regulated and represent 99% of its overall business, measured by revenues. These businesses generate stable and growing net cash from operating activities and net income. Hydro One's net cash from operating activities grew to $1,256 million in 2014 from $892 million in 2009 and $911 million in 2004, representing a compound annual growth rate of 7.1% and 3.3% on a five and ten year basis, respectively. Hydro One's net income grew to $747 million in 2014 from $470 million in 2009 and $498 million in 2004, representing a compound annual growth rate of 9.7% and 4.1% on a five-and ten-year basis, respectively.

Hydro One Inc. has been a reporting issuer in Canada for over 15 years and has been an active participant in the public debt markets. Hydro One Inc. has one of the strongest credit profiles of any public company regulated electricity utility in Canada, with its debt currently rated A (stable) by Standard & Poor's, A2 (negative) by Moody's, and A (high) (under review with developing implications) by DBRS. Standard & Poor's has also assigned a long-term corporate credit rating to Hydro One Limited of A (stable). Hydro One Inc. has a strong track record of raising capital in the public debt markets, and has raised over $3.2 billion in gross proceeds through the sale of debt in the past three and a half years alone. Management expects that maintaining a strong credit profile and low cost of borrowing will be a key element of Hydro One's business and regulatory strategy following this offering, and that Hydro One will have significant debt capacity to fund future investments. Hydro One Inc. will remain a reporting issuer in Canada following the closing of this offering. Hydro One Limited does not intend to provide a guarantee in respect of Hydro One Inc.'s debt.

Driven by a stable regulated business, strong "A" category credit ratings and projected increases in its rate base, Hydro One expects to continue generating stable and growing net cash from operating activities to fund its ongoing sustaining capital investments and to support a strong and growing dividend. Additionally, the Company intends to use a portion of its net cash from operating activities in combination with additional debt to fund future development capital investments.

Robust and Predictable Growth Profile

Additions to Rate Base through Approved Capital Expenditures

Hydro One must continually invest in its transmission and distribution businesses in order to provide safe and reliable electricity service and meet its obligations as a regulated utility. A significant number of Hydro One's transmission and distribution assets were built in the 1960s and 1970s or earlier and are reaching the end of their service lives. The Company therefore expects that it will be required to make significant investments in its existing infrastructure over the long term. Over the past five fiscal years, the Company has spent an average of $1.5 billion per year on capital expenditures. When placed into service, these investments add to Hydro One's rate base, which grew during that period from $11.6 billion to $16.3 billion, representing a compound annual growth rate of 7.1%.

The Company incurs capital expenditures to maintain safety, reliability and integrity of its transmission and distribution assets and to allow for prudent growth necessary to continue to meet the evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital expenditures, which are required to support the continued operation of Hydro One's existing assets, and development capital expenditures, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations. Sustaining capital expenditures are recurring in nature and involve less regulatory and completion risk compared to large scale development projects.

Hydro One anticipates that it will spend an average of $1.5 billion per year over the next five years on total capital expenditures, with sustaining capital expenditures representing an average of approximately 60% of total capital expenditures in each year. The Company anticipates that these investments will contribute to improved reliability, customer service and operating efficiencies, as well as increased net cash from operating activities and net income from a growing rate base.

Projected Capital Expenditures for Transmission and Distribution Businesses	2015	2016	2017	2018	2019
			(millions)		
Transmission	$ 899	$ 866	$ 848	$ 839	$ 832
Distribution	$ 665	$ 669	$ 674	$ 678	$ 682
Total	**$1,564**	**$1,535**	**$1,522**	**$1,517**	**$1,514**

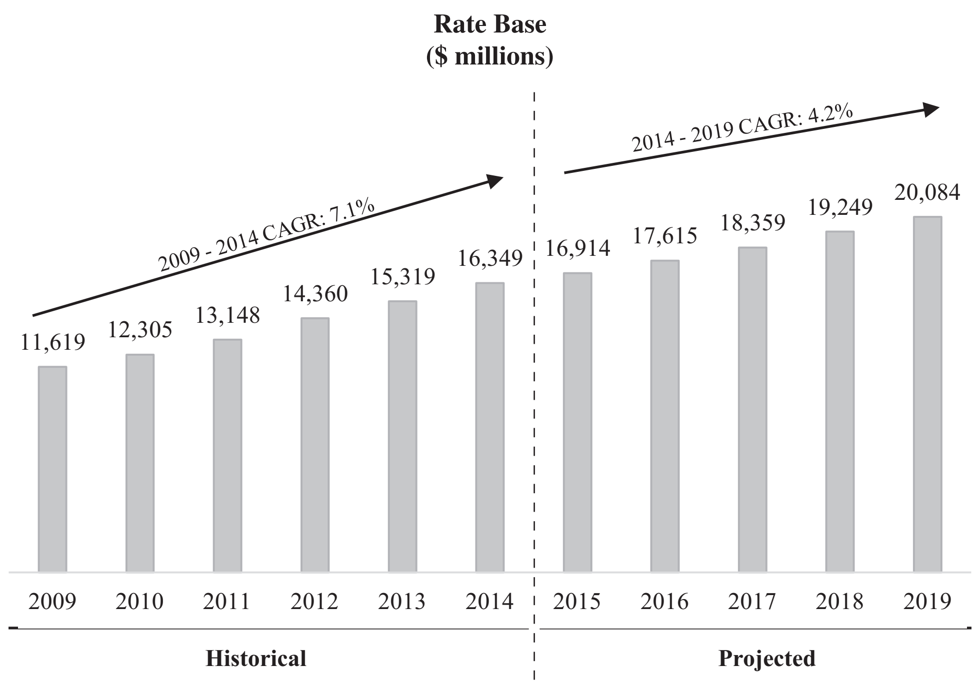
Projected Capital Expenditures by Category	2015	2016	2017	2018	2019
			(millions)		
Sustaining	$ 905	$ 891	$ 955	$1,022	$ 978
Development	$ 470	$ 444	$ 381	$ 321	$ 379
Other	$ 189	$ 200	$ 186	$ 174	$ 157
Total	**$1,564**	**$1,535**	**$1,522**	**$1,517**	**$1,514**

Notes:

(1) Projected capital expenditures may be considered forward-looking information, and reflect the Company's current expectations and assumptions relating to projects contemplated in the Company's capital expenditure programs and Ontario Energy Board approvals received to date. Transmission capital expenditures for 2015 and 2016 were previously approved by the board of directors of Hydro One Inc. and are consistent with the capital expenditures information presented in the most recent transmission rates application filed with the Ontario Energy Board, which led to the Ontario Energy Board's approval of Hydro One's 2015 rate order for transmission services. Distribution capital expenditures for 2015, 2016 and 2017 were previously approved by the board of directors of Hydro One Inc. and are consistent with the capital expenditures information presented in the most recent distribution rate application filed with the Ontario Energy Board, which led to the Ontario Energy Board's distribution rates decision for Hydro One's 2015, 2016 and 2017 years. Actual capital expenditures for any of the years referred to above may be greater or less than projected capital expenditures. See "Forward-Looking Information". See "Risk Factors" for a discussion of material factors that could cause actual capital expenditures to differ from projected capital expenditures.

(2) "Other" capital expenditures consist of special projects, such as those relating to information technology.

The impact of Hydro One's capital expenditures on its rate base is illustrated in the following graph, which shows both the historical rate base of Hydro One for the past five fiscal years and its projected rate base over the next five fiscal years through the addition of assets that are anticipated to be placed into service.



Notes:

(1) "CAGR" means compound annual growth rate.

(2) Projected rate base may be considered forward-looking information. The rate base in each year represents the combined rate base for Hydro One's transmission and distribution businesses. The transmission rate bases of Hydro One Networks Inc. for 2015 and 2016 have been approved by the Ontario Energy Board, subject to certain conditions in respect of in-service additions. The distribution rate bases of Hydro One Networks Inc. for 2015, 2016 and 2017, have been approved by the Ontario Energy Board. Transmission rate bases for 2017, 2018 and 2019, and distribution rate bases for 2018 and 2019, are projected based on Hydro One's current expectations and assumptions regarding investments in its transmission and distribution infrastructure and the timing of assets being included in Hydro One's rate base, and will be subject to Ontario Energy Board approval in connection with Hydro One's rate applications for those years. Transmission rate bases for 2017, 2018 and 2019, and distribution rate bases for 2018 and 2019, as approved by the Ontario Energy Board, may be higher or lower than the rate bases shown. See "Forward-Looking Information".

Development Capital Projects

Hydro One anticipates spending an average of approximately $400 million per year over the next five years on development capital projects for its transmission and distribution businesses. These capital projects typically involve longer development timelines. Hydro One has significant development experience, having designed and built substantially all of Ontario's transmission system and a large portion of its distribution system. This includes the Bruce-to-Milton transmission project, which was completed in 2012 on budget and six months ahead of schedule. This was the largest transmission infrastructure project in Ontario in 20 years and involved the construction of approximately 700 transmission towers and approximately 180 kilometres of double circuit lines. More recently, Hydro One was selected to develop the Northwest Bulk Transmission Line, another large scale transmission project that, if approved by the Ontario Energy Board, would reinforce the connection between Thunder Bay and Dryden.

As the Company owns substantially all of Ontario's transmission network, the Company believes that additional development opportunities for Hydro One may arise as a result of the requirement to connect new transmission lines to Hydro One's transmission system, even where Hydro One may not be the developer of the new line. For instance, in the case of the East-West Tie Line, which is being developed by NextBridge Infrastructure, management estimates that Hydro One may need to invest over $100 million in station upgrades in order to connect the new line to Hydro One's transmission system if the project is approved by the Ontario Energy Board.

Acquisition Opportunities

As the largest distributor in Ontario, Hydro One has been an active consolidator of local distribution companies. In the late 1990s and early 2000s, when significant changes were made to the electricity sector in Ontario, Hydro One acquired 88 individual local distribution companies, which were subsequently integrated into Hydro One's distribution business (with the exception of Hydro One Brampton Networks Inc., which was operated as a stand-alone entity). More recently, the Company acquired Haldimand Hydro in June 2015 and Norfolk Power in August 2014, adding more than 40,000 customers to its distribution network. A third Hydro One acquisition, of Woodstock Hydro, received Ontario Energy Board approval on September 11, 2015 and is expected to close later in 2015. Through these recent acquisitions, the Company will have increased its customer base by approximately 5%. Hydro One will continue to evaluate local distribution company consolidation opportunities in Ontario in the future and intends to pursue those acquisitions which deliver value to the Company and its shareholders.

Over time, the Company may also consider larger-scale acquisition opportunities or other strategic initiatives outside of Ontario to diversify its asset base and to leverage its strong operational expertise. These acquisition opportunities may include other providers of electrical transmission, distribution and other similar services in Canada or in the United States.

Significant Scale and Leadership Position in Ontario

Hydro One plays an essential role in the electricity system of Canada's most populous province. Hydro One owns and operates substantially all of Ontario's transmission system, and is also the largest electricity distributor in Ontario. Management believes that Hydro One's significant scale and leading position in the electricity industry in Ontario provides it with several key competitive advantages that may not be available to smaller utilities, including:

- a low cost of borrowing and broad access to debt capital markets in order to fund its development and growth initiatives,
- the ability to draw on a large and highly experienced in-house team of experts covering all key aspects of Hydro One's business, including asset management, operations, post-outage recovery, project design, engineering, procurement, project management and construction,
- the resources and commitment to prudently invest in innovation, continuous improvement and customer service initiatives and to improve the reliability and performance of Hydro One's transmission and distribution systems and reduce operations, maintenance and administration costs,
- a refined and comprehensive stakeholder engagement process that covers Hydro One's customers, municipalities, remote communities and other parties,
- extensive experience building and maintaining effective relationships with First Nations and Métis communities, and
- a leading role in working with regulatory authorities on developments with respect to energy policy, regulatory changes, new transmission and distribution investments, regional planning and new technologies.

Management believes that these strengths have increased Hydro One's operational effectiveness, helped it maintain a positive and constructive relationship with its regulators, customers and stakeholders and ultimately contributed to achieving successful outcomes in its applications for the approval of transmission and distribution rates, new development projects and the acquisition of local distribution companies.

Consistent and Stable, Rate-Regulated Environment

Hydro One's transmission and distribution businesses operate in a stable, rate-regulated environment. Management believes the Ontario Energy Board is regarded in the electricity industry as a stable and sophisticated regulator with a transparent and predictable rate setting process. The allowed return on equity determined by the Ontario Energy Board is set by a formula linked to long-term government bond yields and corporate bond spreads. See "Rate-Regulated Utilities – Value Drivers for a Rate-Regulated Utility – Return on Equity". Hydro One does not set the price of electricity and has no direct exposure to electricity price risk because the cost of electricity is passed on directly to consumers. The rates approved by the Ontario Energy Board for transmission and distribution services are intended to allow utilities to recover their cost of providing services and earn an allowed return on equity, while achieving productivity gains for the mutual benefit of utilities and their customers.

Over the past six years, the Company's allowed return on equity approved by the Ontario Energy Board has ranged from 8.39% to 9.66% for its transmission business and 9.30% to 9.85% for its distribution business.

Allowed Return on Equity

	2010	2011	2012	2013	2014	2015
Transmission	8.39%	9.66%	9.42%	8.93%	9.36%	9.30%
Distribution	9.85%	9.66%	9.66%	9.66%	9.66%	9.30%

Notes:

(1) Management anticipates that the return on equity set by the Ontario Energy Board will be lower in 2016 compared to 2015 due to decreases in interest rates.

Hydro One has earned or exceeded its allowed return on equity on a consolidated basis. For instance, the Company's actual returns on equity were 10.60% in 2010, 10.50% in 2011, 11.50% in 2012, 11.50% in 2013 and 10.00% in 2014, in each case, on a consolidated basis.

Proven Senior Management Team and Experienced Independent Board of Directors

Following this offering, Hydro One Limited will operate as an independent, commercially-oriented public company, with an experienced, independent board of directors and proven senior leadership team. Hydro One's current leadership has demonstrated the capability to execute Hydro One's strategic plan and drive performance improvements and shareholder returns. The Company will operate with an independent board of directors and autonomous decision making. As a shareholder of Hydro One Limited, the Province will engage in the business and affairs of Hydro One as an investor and not as a manager, as contemplated by the Governance Agreement. To support Hydro One's new direction, a new board of directors and senior leadership team were appointed in connection with this offering. Members of the new board of directors meet high standards of independence, commercial experience and director expertise and will oversee the Company's strategy, operations and growth as a publicly-listed company. The group includes Canadian business leaders, electricity sector experts, corporate directors and a former provincial Ombudsman.

Hydro One will be led by a highly experienced management team that together has extensive industry, operating and public company experience. Mayo Schmidt, the Company's new President and Chief Executive Officer, was formerly the Chief Executive Officer of Viterra Inc. and its predecessor, Saskatchewan Wheat Pool. Mr. Schmidt has a track record of leading large scale business transformation and growth while generating value and benefits for investors, employees and customers. At Viterra, Mr. Schmidt transformed a relatively small regional co-operative into a publicly-held, multi-billion dollar corporation with nearly 7,000 employees and operations around the world. In recognition of his accomplishments at Viterra, Mr. Schmidt was named "Chief Executive of the Year in 2009" by Canadian Business Magazine. Michael Vels, the Company's new Chief Financial Officer, was formerly the Chief Financial Officer of Maple Leaf Foods Inc. Mr. Vels brings to Hydro One considerable executive level experience in public company governance, debt and equity capital raising, mergers and acquisitions, business transformation and information technology. Mr. Schmidt and Mr. Vels join an established management team at Hydro One that has extensive experience with the Company's operations, assets and regulators. Mr. Schmidt and Mr. Vels are committed to improving the management of the Company and driving performance improvements and cultural change.

Transmission Business

Overview

Hydro One’s transmission business consists of owning, operating and maintaining Hydro One’s transmission system, which accounts for 96% of Ontario’s transmission network. This includes the Company’s 66% interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation, which owns most of the assets relating to specific Bruce-to-Milton transmission line assets. The Company’s transmission business is one of the largest in North America, and is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. The Company’s transmission rates are determined based on a cost of service model. Transmission rates are collected by the IESO and are remitted by the IESO to Hydro One on a monthly basis, which means that Hydro One’s transmission business has no direct exposure to end-customer counterparty risk.

Transmission rates are based on monthly peak electricity demand across Hydro One’s transmission network. This gives rise to seasonal variations in Hydro One’s transmission revenues, which are generally higher in the summer and winter due to increased demand, and lower during other periods of reduced demand. Hydro One’s transmission revenues also include export revenues associated with transmitting excess generation to markets outside of Ontario. Ancillary revenue include revenues from providing maintenance services to generators and from allowing third parties to use certain Company lands.

Business

The Company’s transmission system serves substantially all of Ontario, with the exception of the Sault Ste. Marie, James Bay and Fort Erie areas, and transported approximately 139.8 TWh of energy throughout the province in 2014. Hydro One’s transmission customers consist of 48 local distribution companies (including Hydro One’s own distribution business) and 90 large industrial customers connected directly to the transmission network, including automotive, manufacturing, chemical and natural resources businesses. Electricity delivered over the Company’s transmission network is supplied by 116 generators in Ontario and electricity sourced from outside the province through interties.

The high voltage power lines in Hydro One’s transmission network are categorized as either lines which form part of the “bulk electricity system”, or “area supply lines”. Power lines which form part of the bulk electricity system typically connect major generation facilities with transmission stations and often cover long distances, while area supply lines serve a local region. Ontario’s transmission system is connected to the transmission systems of Manitoba, Michigan, Minnesota, New York and Québec through the use of interties, allowing for the import and export of electricity to and from Ontario.

Hydro One’s transmission assets were $12,822 million as at June 30, 2015 and include transmission stations, transmission lines, a control centre and telecommunications facilities. Hydro One has approximately 291 transmission stations and approximately 29,000 circuit kilometres of high voltage lines whose major components include cables, conductors and wood or steel support structures. All of these lines are overhead power lines except for approximately 274 circuit kilometres of underground cables located in certain urban areas.

B2M Limited Partnership is Hydro One’s partnership with the Saugeen Ojibway Nation with respect to the Bruce-to-Milton transmission line. B2M Limited Partnership owns the high-voltage transmission lines and related equipment, such as the steel support structures, conductors and foundations, while Hydro One owns the transmission stations that connect to the lines. Hydro One maintains and operates the Bruce-to-Milton line. It also owns the general partner of B2M Limited Partnership, and has a 66% economic interest in the partnership.

Hydro One’s transmission network is managed from a central location north of Toronto, Ontario. This centre monitors and controls the Company’s entire transmission network, and has the capability to remotely monitor and operate transmission equipment, respond to alarms and contingencies and restore and re-route interrupted power. There is a fully functional back-up facility which would be staffed in the event of an evacuation of the centre. The Company is currently developing plans to replace its current back-up facility with a new facility.

Hydro One uses special telecommunications systems that are necessary for the protection and operation of its transmission and distribution networks. These systems are subject to very stringent reliability and security requirements, as they must be secure and continue to function during periods of prolonged power outages. These systems help the Company meet its reliability obligations and facilitate the restoration of power following service interruptions.

Regulation

Transmission Rate Setting

In Ontario, transmission rates are currently determined based on a cost of service model. The Ontario Energy Board sets transmission rates based on a two-step process.

First, all transmitters, including Hydro One, apply to the Ontario Energy Board for the approval of their revenue requirements, which cover the transmitters' cost of service for providing transmission services and allowed return on equity. Once approved by the Ontario Energy Board, transmission revenue requirements generally cover the subsequent two-year period with an acknowledged adjustment to occur in the second year to update for the then current cost of debt and return on equity.

Second, the Ontario Energy Board aggregates the total revenue requirements of all transmitters in Ontario and applies a formula in order to arrive at a single set of rates that are charged for the three types of transmission services applicable in Ontario. These consist of network services, line connection services and transformation connection services. The three separate rates charged for these services are the same for all transmitters, and are referred to in Ontario as "uniform transmission rates".

Uniform transmission rates for all transmitters are set by the Ontario Energy Board on an annual basis, using the revenue requirements set out in the most recent rate decision issued with respect to each transmitter.

Applications to the Ontario Energy Board for the approval of a transmitter's revenue requirements use a forward test year. See "Rate-Regulated Utilities – Rate Applications in Ontario – Application Process". A transmitter earns more revenues from transmission rates when peak electricity demand is higher than forecast in its rate application, and conversely earns less revenues from transmission rates when peak electricity demand is lower than forecast in its rate application.

Recent Transmission Rate Applications

Hydro One and B2M Limited Partnership make separate applications for the approval of their revenue requirements for transmission services based on a cost of service model.

On January 8, 2015, the Ontario Energy Board approved Hydro One's 2015 transmission rate order for transmission services, which provided for a revenue requirement of $1,477 million for 2015 and $1,516 million for 2016. These revenue requirements reflect an approved rate base of $9,651 million, return on equity of 9.30% and deemed capital structure of 60% debt and 40% equity. The Ontario Energy Board annually adjusts Hydro One's revenue requirements previously approved in a rate decision to reflect more current costs of debt and return on equity. The adjustment to Hydro One's 2016 revenue requirement will be reflected in a subsequent rate order. Management anticipates that the revenue requirement for 2016 will be adjusted downward due to an anticipated decrease in the allowable return on equity set by the Ontario Energy Board, reflecting lower interest rates.

B2M Limited Partnership is currently subject to an interim rate order that was approved by the Ontario Energy Board in December 2014. In March 2015, B2M Limited Partnership filed an application for revenue requirements covering the 2015 to 2019 period. B2M Limited Partnership has requested revenue requirements of $39 million for 2015, $36 million for 2016, $37 million for 2017, $38 million for 2018 and $37 million for 2019. A decision is expected in the fourth quarter of 2015.

For a summary of Hydro One's recent applications to the Ontario Energy Board, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Developments in 2015 – Applications to the Ontario Energy Board". Copies of Hydro One's applications to the Ontario Energy Board and related documentation and the approvals of the Ontario Energy Board are publicly available on the website of the Ontario Energy Board at www.ontarioenergyboard.ca. Such applications, documentation and approvals are not incorporated by reference in, and do not form part of, this prospectus.

Reliability Standards for Transmission

The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC, both of which are industry organizations involved in promoting and improving the reliability of transmission networks in North America. These reliability standards are enforced by both the IESO and the National Energy Board.

Among its standards, the NERC has also established and continues to issue revised requirements to ensure that utilities and other users, owners and operators of the bulk electricity system in North America have appropriate procedures in place to protect critical infrastructure from cyber-attack. Hydro One's physical, electronic and information security processes have been and are being upgraded to meet these revised requirements. Hydro One expects to continue to perform additional work and incur further costs in order to comply with the NERC's updated and revised standards.

Hydro One anticipates that the costs associated with meeting applicable reliability and critical infrastructure standards will be incurred annually over a number of years, and will be recovered in rates.

Regional Planning

The Ontario Energy Board oversees regional planning processes to ensure that transmission and distribution investments are coordinated at a regional level. The Ontario Energy Board has indicated it will rely on regional planning studies and reports to support rate applications submitted by transmitters and distributors and "leave to construct" applications submitted by transmitters. In Ontario, the regional planning process is led by the transmitter responsible for a particular geographic region. For this purpose, the province is divided into 21 regions. As Hydro One is the largest transmitter in Ontario, it plays a key role in the regional planning process and is responsible for leading the regional planning process in 19 of the 21 designated regions. The completion of the first cycle of regional plans is expected over the next two years. Once a plan is finalized and approved by the Ontario Energy Board, the transmitter responsible for each region will implement the recommended transmission investments and distributors in the region will implement the recommended distribution investments in their respective service territories.

In conducting the regional planning, Hydro One works closely with the IESO and all distributors in the region to jointly identify needs and develop transmission and distribution investment options. Hydro One also coordinates with the IESO on its Integrated Regional Resource Planning process.

Capital Expenditures

The Company's transmission capital expenditure plan is designed to address Ontario's changing generation profile, accommodate load growth in areas throughout Ontario and support the expected increase in renewable energy generation. Additionally, this plan seeks to sustain or improve Hydro One's transmission reliability performance, as determined by measures such as the average length (in minutes) of unplanned interruptions per delivery point. The Company's capital expenditure plans are included in Hydro One's applications for transmission rates submitted to the Ontario Energy Board.

Investments in Hydro One's existing infrastructure are critical in order to maintain the safety, reliability and integrity of its transmission network. The Company incurs both sustaining capital expenditures and development capital expenditures required to upgrade or to enhance Hydro One's system capabilities and networks. Sustaining capital expenditures are those investments required to replace or refurbish lines or station components to ensure that existing transmission assets function as originally designed. Development capital expenditures include those investments required to develop and build large-scale projects such as new transmission lines and stations as well as smaller projects such as transmission line or station reinforcements, extensions or additions. The Company expects that it will be required to make significant investments in its existing infrastructure over the long term. The Company anticipates that it will spend $800 million to $900 million per year over the next five years on capital expenditures relating to its transmission business. See "Business of Hydro One – Investment Highlights – Robust and Predictable Growth Profile". Work related to the Company's sustaining or development capital projects may require the Company to shut down primary transmission lines in order to accommodate the work. While this may increase the duration of outages, the Company believes it is important to continue with its planned capital projects work. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Summary of Annual Results – Performance Measures and Targets – Continuous Improvement and Cost-effectiveness".

Hydro One's plans to maintain, refurbish or replace existing assets are developed on the basis of maintenance standards, transmission asset condition assessments and end-of-service life criteria specific to each type of asset.

Priorities are assigned to each type of investment based on the risks that it mitigates. Hydro One is continuously enhancing its asset planning process through the development and use of new tools. Multi-variable planning optimization software is employed to develop a prioritized portfolio of investments spanning Hydro One's entire operations, in order to establish investment plans that manage the risks associated with electrical safety, reliability, environmental considerations, customer satisfaction and operational efficiencies.

A key input to Hydro One's planning process and the optimization software is an accurate assessment of transmission asset condition. In 2013, Hydro One began using its Asset Analytics tool, which uses data regarding its assets and performance algorithms to improve its ability to establish transmission asset condition and criticality. The results from the tool support fact-based decisions regarding maintenance, refurbishment or replacement needs of specific assets and are one of a number of key inputs into the planning process. The Asset Analytics tool is relatively new and the Company continues to work on adding to this tool's data set, improving the quality of its data and refining its algorithms and logic. Hydro One's planners use the information drawn from the Asset Analytics tool along with other information and data to make planning or investment decisions.

The Company also engages with various stakeholders, including its customers, to determine the need, timing and technical solutions for new connection and transmission facilities or upgrades, as well as with affected communities and parties who may be impacted by the project. The Company also engages with First Nations and Métis communities whose rights may be affected as part of the project development process for new or upgraded transmission lines.

Competitive Conditions

The Company's operations are currently limited to Ontario, where the Company operates and maintains substantially all of Ontario's transmission system. Competition for transmission services in Ontario is currently limited. The adoption by the Ontario Energy Board of uniform transmission rates that apply to all transmitters also reduces the financial incentive for customers to seek alternative transmission providers, since each transmitter in Ontario charges the same uniform rate for transmission services. Hydro One competes with other transmitters for the opportunity to build new large-scale transmission facilities in Ontario. Management believes that Hydro One is well-positioned to pursue the development of such facilities. Hydro One does not compete with other transmitters with respect to investments which are made to sustain or develop its existing transmission infrastructure.

Distribution Business

Overview

Hydro One's distribution business consists of owning, operating and maintaining Hydro One's distribution system, which it owns primarily through Hydro One Networks Inc., the largest local distribution company in Ontario. The Company's distribution system is also the largest in Ontario. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the Ontario Energy Board. The Company's distribution rates are generally determined using a performance-based model, except for the distribution rates of Hydro One Remote Communities Inc., which are set on a cost recovery basis and do not include a return on equity.

Distribution revenues include distribution rates approved by the Ontario Energy Board and amounts to reimburse Hydro One for the cost of purchasing electricity delivered to its distribution customers. Distribution revenues also include minor ancillary service revenues, such as fees related to the joint use of the Company's distribution poles by participants in the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

As at June 30, 2015, Hydro One's distribution assets were $9,888 million, including Hydro One Brampton Networks Inc. Hydro One's current distribution business no longer includes the business of Hydro One Brampton Networks Inc. as on August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions.

Business

During 2014, Hydro One (excluding Hydro One Brampton Networks Inc.) delivered electricity through its distribution network to approximately 1.3 million residential and business customers, most of whom are located in rural areas, as well as 56 local distribution companies.

Hydro One's distribution system (excluding Hydro One Brampton Networks Inc.) includes approximately 122,000 circuit kilometres of primary low-voltage distribution lines and approximately 1,000 distribution and regulating stations. Other distribution assets include poles, transformers, service centres and equipment.

Hydro One's distribution system was designed to service a rural territory. Because of the lower population density in the Company's service territory, the Company's costs to provide distribution services may be higher than distributors who service urban areas. As well, unlike the distribution systems found in urban areas, Hydro One's distribution system was not designed to be inter-connected in loops with other distribution lines, with the result that interruptions experienced at any point along a distribution line in Hydro One's network can cause all customers downstream of the interruption point to lose power. Accordingly, the reliability of Hydro One's distribution system would generally be expected to be inherently lower than that of local distribution companies which service urban territories. Fallen trees and component failures on the Company's distribution lines require immediate repair or replacement in order to restore service. As a result, the Company engages in vegetation management activities to maintain the reliability of Hydro One's distribution system on a preventative basis. This consists of the trimming or removal of trees to lower the risk of contact with distribution lines, thereby reducing the risk of power outages. The Company's monitoring systems assist with determining areas of priority and with system restoration. The Company relies on its local line crews comprised of full-time and union hiring hall staff for these preventive power outage and restoration activities. Hydro One may have a longer vegetation management cycle as compared with that of other local distribution companies. The Company believes this is consistent with its goal of maintaining a reasonable balance of reliability for its distribution system at a reasonable cost to its customers.

The Company completed the acquisitions of Haldimand Hydro in June 2015 and Norfolk Power in August 2014, adding more than 40,000 customers to its distribution network. A third acquisition – Hydro One's acquisition of Woodstock Hydro – received Ontario Energy Board approval on September 11, 2015 and is expected to close later in 2015. Woodstock Hydro has approximately 16,000 customers. Through these acquisitions, the Company will have increased its customer base by approximately 5%. Customers of Haldimand Hydro and Norfolk Power have seen, and customers of Woodstock Hydro are expected to see, a reduction in their monthly distribution rates, as well as a freeze in distribution rates for five years.

Hydro One is committed to continuously improving customer service and putting customers first. This includes specific, measurable commitments to customers that encompass all areas of service, backed-up by best-in-class practices and performance metrics that Hydro One will share openly with its customers. The Company implemented a new billing system in 2013 as part of a larger initiative to adopt a new enterprise management platform. In connection with this implementation, some of Hydro One's customers experienced problems with their electricity bills, including errors or delays in receiving bills. The Company corrected the cause of these errors and delays and sought to address the resulting inconvenience caused to customers. Hydro One's new billing system is now outperforming its previous system in terms of timeliness, accuracy and reliability. Better processes have also been implemented for addressing and resolving billing issues in a timely manner. For the second quarter of 2015, "billing accuracy", as defined by the Ontario Energy Board, was 98.6% against Hydro One's target of 98.0% (which reflects the approval by the Ontario Energy Board of an exemption application excluding certain customers from this calculation), and the Company's internal measure of billing quality was 99.8% against a target of 99.0%. Further action and improvements are continuing to be pursued. Despite having taken these measures, the Company understands that a customer of Hydro One has commenced an action, proposed as a class action, alleging improper billing and account management practices in connection with the implementation of Hydro One's billing system. This claim is in a very early stage and has not been certified as a class action. Hydro One intends to defend the action. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Developments in 2015 – Class Action Lawsuit".

Hydro One's distribution business is involved in the connection of new sources of electricity generation, including renewable energy. Hydro One invests in upgrades and modifications to its distribution system in order to accommodate these new sources of generation and ensure the continued reliability of its distribution network. Hydro One has connected approximately 13,000 small, mid-size and large embedded generators to its distribution network, including approximately 12,200 generators with capacities of up to 10 kW. Hydro One also currently has approximately 1,500 generators that are pending connection.

As the largest distributor in Ontario, Hydro One played a major role in the installation of smart meters and the migration of distribution customers to time of use pricing. Smart meters are regarded by the Province and Hydro One as an integral means of promoting a culture of conservation. As of December 31, 2014, Hydro One had installed approximately 1.4 million smart meters (including smart meters for customers of Hydro One Brampton Networks Inc.), which provide customers with access to information about their electricity consumption on a daily basis, allowing customers to change their electricity consumption patterns and reduce their costs. Hydro One has completed all material activities associated with the implementation of smart meters, and has transitioned the vast majority of its customers to time of use pricing.

Hydro One's distribution business also includes the business of its wholly-owned subsidiary, Hydro One Remote Communities Inc., which supplies electricity to customers in remote communities in northern Ontario. Electricity used by these remote communities is produced by diesel generators, supplemented by small amounts of wind or hydroelectric generation. Hydro One operates this business on a cost recovery basis.

Regulation

Distribution Rates

In Ontario, distribution rates are determined using a performance-based model set out in the Ontario Energy Board's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, which is sometimes referred to as the "**RRFE**". Under the RRFE, which was issued in 2012, distributors in Ontario may choose one of three rate-setting methods, depending on their capital requirements:

- **4th Generation Incentive Rate-Setting** – suitable for distributors that anticipate some incremental investment needs will arise during the plan term,
- **Custom Incentive Rate-Setting** – suitable for those distributors with large or highly variable capital requirements, and
- **Annual Incentive Rate-Setting Index** – suitable for distributors with limited incremental capital requirements.

The RRFE contemplates that a distributor will apply for the approval of its revenue requirement for an initial base year covered by the rate decision. The revenue requirement for subsequent years is determined based on a formula that accounts for inflation and certain productivity factors set by the regulator. The revenue requirement in these subsequent years is set on the assumption that the distributor is lowering its cost of service over the period covered by the rate decision due to efficiency or productivity improvements. The RRFE allows the distributor to retain all or a portion of the cost savings achieved in excess of those established by the regulator during the period covered by the rate decision. This allows the distributor to earn more than its allowed return on equity.

The RRFE provides incentives for distributors to achieve certain performance outcomes, namely:

- **Customer Focus** – services are provided in a manner that responds to identified customer preferences,
- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives,
- **Public Policy Responsiveness** – utilities deliver on obligations mandated by government, and
- **Financial Performance** – financial viability is maintained and savings from operational effectiveness are sustainable.

A distributor must submit proposed performance measures as part of its application for distribution rates under the RRFE. The Ontario Energy Board issued its report, *Performance Measurement for Electricity Distributors: A Scorecard Approach*, which sets out its policies on measures to assess a distributor's effectiveness and methods of improvement in achieving the performance outcomes referred to above. The scorecard currently contains quantitative measures in the areas of service quality, customer satisfaction, safety, system reliability, asset management, cost control and financial ratios.

Distributors may also propose their own performance measures for approval by the Ontario Energy Board. In its most recent distribution application, Hydro One submitted eight additional quantitative measures relating to areas that will be the subject of increased spending levels over the next few years, such as pole replacements, distribution station refurbishments and vegetation management. Distributors are required to report to the Ontario Energy Board on their performance against the performance measures approved as part of their most recent rate decision.

The Ontario Energy Board's review process under the RRFE follows a similar process to that of a transmission rate application for the review of the anticipated cost of service for providing distribution services, other than as noted above. Once the revenue requirement for distribution services is determined, it is allocated across the distributor's customer rate classes using a methodology approved by the Ontario Energy Board. This results in the setting of individual rates for distribution services based on each customer rate class. Customer rate classes for Hydro One are reflective of the size and type of customer (such as residential, small commercial, large commercial/industrial, etc.) and are in part tied to the population density of the areas served (such as high density urban areas, medium density areas, and low density rural areas). Hydro One currently has 13 customer classes.

Unlike uniform transmission rates, distribution rates in Ontario are not the same for all distributors and reflect the particular circumstances of each distributor, including its own costs of providing electricity service to its own particular customers. The recently issued Ontario Energy Board policy, *A New Distribution Rate Design for Residential Electricity Customers*, will change the current distribution rate design (a combination of a fixed monthly rate and a variable charge) to a fixed monthly charge only. Implementation will occur over the next four to seven years for Hydro One's residential customers.

The OEB has also initiated a working group to consider possible changes to the design of rates for commercial industrial customers. Changes to rate design will not impact the rates revenue requirement to be collected for each customer class.

Distribution Rate Applications

The Company's distribution rates, other than the distribution rates of Hydro One Remote Communities Inc., are determined using a performance-based model.

In December 2013, Hydro One filed its 2015 to 2019 distribution rate application with the Ontario Energy Board under the RRFE framework. Hydro One selected the Custom Incentive Rate-Setting option because it believed that this option most closely fit the Company's circumstances, as the Company is contemplating significant capital expenditures over the term of its application, which would have been in excess of what would be permitted under the two other RRFE rate application options. On March 12, 2015, the Ontario Energy Board issued a decision regarding Hydro One's distribution rates for a three year period from 2015 to 2017, providing for a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The 2015 revenue requirement reflects an approved rate base of $6,552 million, return on equity of 9.30% and a deemed capital structure of 60% debt and 40% equity. The rates are effective as of January 1 in each year. Hydro One's revenue requirement for 2016 and 2017 are anticipated to be adjusted to reflect more current costs of debt and return on equity. These adjustments will be reflected in subsequent rate orders. Management anticipates that the revenue requirement for 2016 will be adjusted downward due to an anticipated decrease in the allowable return on equity set by the Ontario Energy Board, reflecting lower interest rates.

Hydro One filed its application as a "Custom Cost of Service" application and included within the application certain productivity improvements and cost performance metrics. However, the Ontario Energy Board did not consider Hydro One's application to be sufficiently aligned with the objectives of the RRFE policy to approve the application as presented. The Ontario Energy Board approved rates for 2015, 2016 and 2017 using a cost of service methodology, based on the evidence that was provided. The Ontario Energy Board directed Hydro One to enhance its next distribution rate application in the areas of outcome-based regulation, externally imposed incentives, benchmarking, continuous improvement and value to customers. This includes the preparation of a number of benchmarking and cost related studies in order to provide the necessary benchmarking evidence and incentives for continuous improvement. Hydro One intends to comply with these directions, and anticipates that rates beyond 2017 will be set under the performance-based model.

Hydro One Remote Communities Inc. is not subject to the Ontario Energy Board's performance-based model for rate-setting, as it is exempt from certain provisions of the Electricity Act which relate to the competitive market. Hydro One Remote Communities Inc. applies for rates on an annual basis. The Ontario Energy Board has approved its distribution rates for 2015. The distribution rates of Hydro One Remote Communities Inc. are set on a cost recovery basis and do not include a return on equity.

For a summary of Hydro One's recent applications to the Ontario Energy Board, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Developments in 2015 – Applications to the Ontario Energy Board". Copies of Hydro One's applications to the Ontario Energy Board and related documentation and the approvals of the Ontario Energy Board are publicly available on the website of the Ontario Energy Board at www.ontarioenergyboard.ca. Such applications, documentation and approvals are not incorporated by reference in, and do not form part of, this prospectus.

Conservation and Demand Management

Conservation initiatives are becoming a more important part of energy policy in Ontario and other jurisdictions. Conservation and demand management ("**CDM**") requirements in Ontario require distributors to achieve specific energy savings targets by encouraging their customers to reduce their energy usage. Distributors seek to achieve these targets through a number of different initiatives, including by offering customers energy saving devices for use at home, cash rebates for the purchase of energy efficient appliances and incentives for the purchase of energy efficient lightbulbs and other products. Distributors are responsible for developing and submitting CDM plans and reporting on their progress towards achieving specific energy-savings targets. The IESO oversees compliance with CDM requirements in Ontario, and also reimburses distributors for the costs of complying with CDM requirements. Hydro One expects that its costs of complying with CDM requirements will be fully reimbursed by the IESO. As a result, CDM-related costs that are reimbursed by the IESO are not included in Hydro One's rate applications to the Ontario Energy Board.

Distributors in Ontario are collectively required to achieve a total of 7 TWh of electricity savings by December 31, 2020, with each local distribution company being allocated individual energy-savings targets. Hydro One Networks Inc.'s distribution business was assigned a peak demand reduction target of approximately 214 MW and an energy reduction target of 1,130 GWh for the 2011-2014 years, which was equivalent to approximately a 5% peak demand reduction and a 5% energy reduction. Hydro One Networks Inc. achieved 167.4 MW in peak demand savings and 898.4 GWh in energy savings, which represent 78.4% and 79.5% of its peak demand and energy reduction targets, respectively. The Ontario Energy Board has recently advised that it will allow rounding up of numbers that end in 0.5% or higher such that the 80% threshold for a CDM target will be considered to have been met if a distributor has achieved 79.5% to 79.9% of its target. As a result, Hydro One Networks Inc. did not meet its peak demand reduction target but is considered to have met 80% of its energy savings target. The Ontario Energy Board has indicated that it will not take any compliance action related to a distributor who does not meet its peak demand target, and will review on a case-by-case basis any instances where a distributor has not met 80% of its energy savings target and will determine next steps at that time. The Ontario Energy Board has further indicated that it expects that distributors will provide detail on their performance in achieving their peak demand and energy savings targets, both successes and challenges. Distributors that have not met at least 80% of their energy savings target are also expected to include details of efforts they took during the 2011-2014 period to address the shortfall in the expected results and to explain why those efforts were insufficient or unsuccessful. As Hydro One Networks Inc. is considered to have achieved 80% of its energy reduction target, it will therefore not be subject to the requirement to include these additional details in its CDM reports.

New targets and budgets were allocated to distributors in October 2014. Hydro One Networks Inc.'s 2015-2020 CDM savings target is 1,159 GWh. Hydro One Networks Inc.'s CDM plan was approved by the IESO on July 8, 2015.

Capital Expenditures

Hydro One is continually engaged in the replacement of distribution assets that have reached the end of their service lives. Capital expenditures for the Company's distribution business in the near term are anticipated to focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. In addition, the Company expects to continue to construct new distribution lines and stations in the future in response to system growth forecasts, continued suburban community development, high load relief requirements and requirements to connect new sources of generation. The Company expects that it will spend $600 million to $700 million per year over the next five years on capital expenditures relating to its distribution business. See "Business of Hydro One – Investment Highlights – Robust and Predictable Growth Profile".

Hydro One is continuing its efforts to make the distribution system more efficient and reliable, including investments in Hydro One's smart grid project, which it refers to as its Distribution Modernization Project. The Distribution Modernization Project involves the development of a functioning smart grid located in Owen Sound, Ontario. Through this project, Hydro One is piloting, testing, validating and creating a foundation for implementing a smart grid on a larger scale in order to enable distributed generation integration, improve reliability and operations, and enhance outage restoration and network planning. Work on the initial phase of the Distribution Modernization Project is expected to be completed by 2017.

Competitive Conditions

Hydro One's distribution service area is set out in its licence issued by the Ontario Energy Board. Only one distributor is permitted to provide distribution services in a service territory, and distributors have exclusive rights to provide service to new customers located within their service territory. As a result, there is very little direct competition for distribution services in Ontario, except near the borders of adjoining service territories where a distributor may apply to the Ontario Energy Board to claim the right to serve new customers who are not currently connected to its distribution grid. In order to create more efficiency in the distribution sector, the Council has endorsed the need for faster consolidation among local distribution companies in Ontario. This may result in competition for acquisition or merger opportunities. Potential acquirors may include strategic and financial buyers, in addition to other local distribution companies.

Other Business

Hydro One's other business segment principally consists of its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, and also markets and sells fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This business is carried out by its wholly-owned subsidiary, Hydro One Telecom Inc.

Hydro One's telecommunications business is not rate-regulated. However, Hydro One Telecom Inc. is registered with the Canadian Radio-television and Telecommunications Commission as a non-dominant, facilities-based carrier, providing broadband telecommunications services in Ontario with connections to Montreal, Québec, Buffalo, New York and Detroit, Michigan.

Review of Operations

Hydro One has been focused on the identification of opportunities for improved corporate performance and the development of strategies to drive more efficient, cost-effective operations. Hydro One conducts regular reviews of key corporate activities and programs, covering areas such as construction services and project management practices, asset deployment and controls, information technology and cybersecurity, vegetation management practices, fleet services and utilization, supply chain management and business continuity planning, and has identified areas requiring improvements. The Ontario Energy Board's rate decisions also contain directions to Hydro One to reduce costs and improve value to customers. In May 2015, the Auditor General of Ontario announced that Hydro One's asset management practices would be covered among the 13 "value-for-money" audits planned for inclusion in her 2015 Annual Report, which is expected to be tabled and become public in December 2015. This will be the last "value-for-money" audit that the Auditor General conducts for Hydro One. Hydro One expects that report to be critical of its management practices in some of these areas, including its interactions with the Ontario Energy Board, and is continuing to work with the Auditor General and her staff in connection with the audit. Hydro One expects to provide formal responses to her recommendations, once finalized, for inclusion in the Auditor General's 2015 Annual Report.

Hydro One's recently appointed board of directors and senior management team are committed to improving the management of the Company's assets and driving performance improvements across the Company's operations. The new management team expects to draw on internal reviews, objectives communicated in the Ontario Energy Board's rate decisions, as well as any recommendations forthcoming in the Auditor General's audit, in developing and implementing the Company's strategy and related performance goals.

First Nations and Métis Communities

Management believes that building and maintaining effective relationships with First Nations and Métis communities is important to achieving the Company's corporate objectives. Hydro One is committed to working with First Nations and Métis peoples in a spirit of cooperation and shared responsibility, which it believes it has been able to demonstrate by developing an equity partnership with the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. Hydro One's First Nations and Métis Relations policy guides all employees of Hydro One, and the Company has a dedicated team responsible for First Nations and Métis matters. Hydro One has several programs in place to ensure that the interests of First Nations and Métis communities and their citizens are considered and addressed. These include dedicated summer student positions, pre-apprenticeship training opportunities, scholarships which provide opportunities for work terms, First Nations and Métis procurement procedures and community investments.

The Company's engagement with First Nations and Métis communities is overseen by the Company's Health, Safety, Environment and First Nations & Métis Committee. This Committee is responsible for assisting the Board in discharging the Board's oversight responsibilities relating to effective occupational health and safety and environmental policies and practices at Hydro One, and its relationship with First Nations and Métis communities.

Employees and Outsourced Services

Hydro One has a highly skilled and flexible work force of over 5,400 regular employees and over 3,300 non-regular employees province-wide, comprising a mix of skilled trades, lines staff, engineering, professional, managerial and executive personnel. Employees work on a variety of projects covering different aspects of the Company's business, which include field work in relation to the Company's transmission and distribution networks, engineering and construction services and stations and operations and maintenance activities. Hydro One's experienced engineering and construction services team was responsible for designing and building Hydro One's transmission system, with approximately one-third of the engineering, procurement and construction work being executed by external contractors.

Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to access highly trained and appropriately skilled workers on a project-by-project basis. This provides the Company with more flexibility to address seasonal needs and unanticipated changes to its budgeted work programs. The Company also offers apprenticeship and technical training programs to ensure that future staffing needs will continue to be met.

Hydro One's capital projects are staffed using a combination of in-house engineering, design, procurement, project management, construction and commissioning personnel and third party service providers who may be contracted to provide some or all of these services, depending on the circumstances. Decisions with respect to the use of third party service providers are made based on the complexity of the capital project, estimated cost differential and an evaluation of various risks and factors. These factors include project risk, potential risks to other assets of Hydro One, the impact on customers and worker safety considerations. Hydro One's experienced hiring hall construction staff is typically utilized for sustainment work on assets involving working in a "live" electricity environment, while third parties are typically engaged for new construction, standard design work or lower risk projects. All construction personnel, regardless of their source, are unionized.

To gain efficiencies and cost reductions, Hydro One has outsourced certain non-core functions, including facilities management services with respect to its stations and other facilities, and certain back-office services such as information technology, payroll, supply chain, call centre and accounting services. Inergi LP (an affiliate of Capgemini Canada Inc.) provides the Company with back-office services and call centre services under an agreement that expires on December 31, 2019 for back-office services and February 28, 2018 for call centre services. The Company has an option to renew the agreement for two additional terms of one year each. Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada) provides the Company with facilities management services under an agreement that expires on December 31, 2024, with an option in favour of the Company to renew the agreement for an additional term of three years.

The following table sets out the number of Hydro One employees represented by unions as of June 30, 2015. The Company also has 614 regular management employees and 28 non-regular management employees.

Union	Regular Employees	Non-Regular Employees
Power Workers' Union	3,455	1,932(1)
The Society of Energy Professionals	1,402	55
Canadian Union of Skilled Workers and construction building trade unions(2)	0	1,351

Notes:

(1) Includes 1642 non-regular "hiring hall" employees covered by the Power Workers' Union agreement.

(2) Employees are jointly represented by both unions. The construction building trade unions have collective agreements with the Electrical Power Sector Construction Association ("EPSCA").

The Power Workers' Union represents the majority of the skilled trade personnel employed by Hydro One. On April 14, 2015, Hydro One Inc. reached an agreement with the Power Workers' Union for the renewal of their collective agreement. This new collective agreement was ratified by the board of directors of Hydro One Inc. on

July 21, 2015 and by the Power Workers' Union on July 3, 2015. The agreement is for a three-year term, covering the period from April 1, 2015 to March 31, 2018. It provides a 1% wage increase annually to the employees represented by the Power Workers' Union, which is offset by savings derived from flexibility negotiated in the collective agreement, including new contracting-out provisions. Under the renewal collective agreement, employees represented by the Power Workers' Union will also be subject to increased annual employee pension contributions. Regular employees who were contributing to the Hydro One Inc. pension plan as of April 1, 2015 will receive, while they remain employed by Hydro One, lump sum cash payments in 2015 and 2016 and annual share grants for a 12 year period after that, made possible as a result of increased employee pension contributions. The share grants will be made under an employee share grant plan to be established by Hydro One Limited prior to the closing of this offering. See "Share Grant Plans". The annual share grant per participant under such plan will be based on 2.7% of an eligible employee's salary as at April 1, 2015. New employees will be subject to the pension contribution increases but will not be eligible for these cash payments and share grants.

The Society of Energy Professionals represents professional and first-level supervisory staff employed by Hydro One. On July 24, 2015, Hydro One Inc. reached an agreement with The Society of Energy Professionals for an early renewal collective agreement. This new collective agreement was ratified by the board of directors of Hydro One Inc. on August 11, 2015 and by The Society of Energy Professionals on August 31, 2015. The agreement is for a three-year term, covering the period from April 1, 2016 to March 31, 2019. It provides a 0.5% wage increase annually to the employees represented by The Society of Energy Professionals, which is offset by savings derived from flexibility within the collective agreement. Under the renewal collective agreement, employees represented by The Society of Energy Professionals will also be subject to increased annual employee pension contributions. Regular employees who were contributing to the Hydro One Inc. pension plan as September 1, 2015 will receive, while they remain employed by Hydro One, lump sum cash payments in 2016 and 2017 and annual share grants for a 12 year period after that, made possible as a result of increased employee pension contributions. The share grants will be made under an employee share grant plan to be established by Hydro One Limited prior to the closing of this offering. See "Share Grant Plans". The annual share grant per participant under such plan will be based on 2.0% of an eligible employee's salary as at September 1, 2015. New employees will be subject to the pension contribution increases but will not be eligible for these cash payments and share grants.

The settlements of the renewal collective agreements for the Power Workers' Union and The Society of Energy Professionals were intended by management to be "net zero," meaning any increase in pay or benefits is expected to be offset by savings elsewhere in the renewal collective agreements. Both renewal collective agreements contain important changes to pension arrangements which are expected to reduce the Company's future exposure to pension costs and move the relative share of pension costs to or close to 50/50 as between employer and employee.

Regular employees represented by The Society of Energy Professionals who are not participants in the employee share grant plan referred to above or whose participation has ended will have the opportunity to participate in an employee share ownership plan to be established by Hydro One Limited. Participants under this plan may elect to contribute between 1% and 4% of their base salary to the plan, with the Company matching 25% of each participant's total contributions, subject to a two year holding requirement. Common shares delivered under this plan will be purchased on the open market.

On July 28, 2015, Hydro One Inc. and the Canadian Union of Skilled Workers reached a renewal collective agreement for a three-year term, covering the period from May 1, 2014 to April 30, 2017. The agreement was ratified by the board of directors of Hydro One Inc. on August 31, 2015 and remains subject to ratification by the Canadian Union of Skilled Workers.

The EPSCA is an employers' association of which Hydro One Inc. is a member. A number of the EPSCA construction collective agreements, which bind Hydro One Inc., expired on April 30, 2015. Tentative agreements have been reached with the United Association of Plumbers and Pipefitters, the Boilermakers, and the Insulators for a five-year term, covering May 1, 2015 to April 30, 2020. These agreements have been ratified by the board of directors of the EPSCA and the unions. Negotiations for renewals for the remaining collective agreements have commenced.

Health, Safety and Environmental Management

Hydro One has integrated the management of health and safety into a single Health, Safety and Environment Management System, which holds OHSAS 18001 registration and is ISO 14001 compliant. OHSAS 18001 is an international recognized standard for occupational health and safety management systems. Effective risk assessment and management are key elements to the successful minimization of risk and performance improvements. Within Hydro One, health, safety and environmental hazards and risks have been identified and assessed and controls have been implemented to mitigate significant risks. The Company has policies in place regarding health and safety, public safety, environmental and workplace human rights and anti-harassment.

In January 2015, Hydro One Networks Inc. was designated a "Sustainable Electricity Company". The Sustainable Electricity Company™ brand mark is a designation established by the Canadian Electricity Association. Companies that wish to use the Sustainable Electricity Company™ brand mark must commit to core subjects, issues and related actions and expectations contained in the standard that are deemed applicable and significant to the Company and its stakeholders. The brand mark is granted for five years, with the option for renewal thereafter. The use of the Sustainable Electricity Company™ brand mark demonstrates Hydro One's commitment to responsible environmental, social and economic practices, and to the principles of sustainable development.

Given the nature of the work undertaken by Hydro One employees, health and safety remains one of the Company's top priorities. The Company is committed to creating and maintaining an injury-free workplace and maintaining public safety through a concentrated focus on the elimination of serious injuries or "near-misses" which have the potential to cause serious injuries. The Company has developed and is continuing to develop a number of programs and initiatives for accident prevention and to minimize the risk of injury to the public associated with its facilities and operations.

Measures are in place to monitor, on a regular basis, health, safety and environment performance using proactive and reactive measures and/or qualitative and quantitative measures. The 10 year evolution of Hydro One's recordable rate, its key health and safety performance measure, has seen an approximate 75% reduction. All measures are monitored by management and by the Health, Safety & Environment and First Nations & Métis Committee. Management compensation has been tied, in part, to success in achieving annual health and safety performance targets. A program allowing for an effective early and safe return to work has allowed the Company to ensure that, when injuries occur, employees recover and return to the workplace as soon as possible.

In 2015, Hydro One continued with its "Journey to Zero" safety initiative that was started in 2009. This initiative compares Hydro One to other companies to see where performance gaps might exist. Safety perception assessments were completed in 2009 and 2013 and will continue in 2015. The results of these assessments identify opportunities for improvement and the development of new health and safety initiatives using cross-functional teams from across the province.

Environmental Regulation

Hydro One is subject to extensive federal, provincial and municipal regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water and land and the generation, storage, transportation, disposal and release of various hazardous substances. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimated changes are accounted for prospectively.

Permits and Approvals

The Company is required to obtain and maintain specified permits and approvals from federal, provincial and municipal authorities relating to the design, construction and operation of new and upgraded transmission and distribution facilities. Examples include environmental assessment approvals, permits for facilities to be located in parks or other regulated areas, water crossing permits, and approvals to discharge to air and water. Some projects may require environmental approvals from the federal government. Interconnections with neighbouring utilities in other provinces and states also require federal approval and will be subject to federal regulatory review.

In general, larger projects are subject to an individual environmental assessment process. The majority of approvals fall under a class environmental assessment process which provides for more streamlined approvals. The scope, timing and cost of environmental assessments are dependent on the scale and type of project, the location (urban versus rural), the environmental sensitivity of affected lands and the significance of potential environmental effects.

Regulation of Releases

Federal, provincial and municipal environmental legislation regulates the release of specific substances into the environment through the prohibition of discharges that will or may have an adverse effect on the environment. Spills and leaks of substances occur in the course of our normal operations. Accordingly, Hydro One has spill, leak prevention and leak mitigation programs involving the testing, replacement, repair and installation of containment systems including re-gasketting of transformers and sulphur-hexafluoride filled equipment. In addition, the Company has an emergency response capability which the Company believes is sufficient to minimize the environmental impact of spills and to comply with its legal obligations.

Hazardous Substances

Hydro One manages a number of hazardous substances, such as PCBs, herbicides, and wood preservatives. In addition, some facilities have substances present which are designated for special treatment under occupational health and safety legislation, such as asbestos, lead and mercury. The Company has environmental management programs in place to deal with PCBs, herbicides, asbestos, and other hazardous substances.

Land Assessment and Remediation

Hydro One has a voluntary land assessment and remediation program in place to identify and, where necessary, remediate historical contamination that has resulted from past operational practices and uses of certain long-lasting chemicals at the Company's facilities. These programs involve the systematic identification of any contamination at or from these facilities and, where necessary, the development of remediation plans for the Company's properties and affected adjacent private properties. Future consolidated expenditures related to Hydro One's land assessment and remediation program are currently estimated at approximately $66 million as at June 30, 2015. These expenditures are expected to be spent over the period ending 2023. The consolidated expenditures on this program for 2014 were approximately $13 million. These costs are expected to be recovered in the Company's transmission and distribution rates.

Insurance

Hydro One maintains insurance coverage, including liability, all risk property, boiler and machinery and directors' and officers' insurance. The Company also maintains other insurance coverage that is required by law, covering risks such as automobile liability, pesticide liability and aircraft liability. The Company does not have insurance for damage to its transmission and distribution wires, poles or towers located outside transmission and distribution stations, including damage caused by severe weather, other natural disasters or catastrophic events or for environmental remediation costs. The Ontario Energy Board has generally permitted the recovery of costs associated with extreme weather events, such as the ice storm that occurred in 1998.

USE OF PROCEEDS

Hydro One will not receive any proceeds from the sale of the common shares by the Province.

The net proceeds of this offering to the Province will be $1,635,949,200 ($1,800,351,000, assuming the exercise of the Over-Allotment Option in full), after deducting the Underwriters' Fee (assuming that 70% of the common shares offered under this prospectus are sold to institutional investors), but excluding the expenses of the offering set out on the cover page of this prospectus, all of which will be borne by the Province.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following presents historical and pro forma summary consolidated financial information of Hydro One Inc., in each case, for the periods ended and as at the dates indicated below. The selected consolidated financial information has been derived from the unaudited interim financial statements of Hydro One Inc. as at and for the three and six month periods ended June 30, 2015 and June 30, 2014 and the audited consolidated financial statements of Hydro One Inc. as at and for the years ended December 31, 2014, December 31, 2013 and December 31, 2012 appearing elsewhere in this prospectus. Hydro One's historical results for any prior period are not necessarily indicative of its results to be expected in any future period. The selected pro forma condensed financial information as at and for the six months ended June 30, 2015 and for the year ended December 31, 2014 has been derived from the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, and give effect to the transactions described in the notes to those statements as if they had occurred on January 1, 2014 for the unaudited pro forma condensed consolidated statements of operations and June 30, 2015 for the unaudited pro forma condensed consolidated balance sheet. Those transactions relate to the following events:

- the payment by Hydro One Inc. and certain of its subsidiaries of the "departure tax", as described in "Departure Tax",
- the recognition by Hydro One Inc. of a deferred tax asset as a consequence of leaving the PILs regime and entering the corporate tax regime (see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results of Operations – Payments in Lieu of Corporate Income Taxes"),
- the recapitalization of Hydro One Networks Inc., as described in "Pre-Closing Transactions", and
- the transfer of all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province, as described in "Pre-Closing Transactions".

The selected pro forma condensed financial information is unaudited, for informational purposes only, and not necessarily indicative of what Hydro One Inc.'s financial position or results of operations would have been had such transactions been completed as at the dates indicated and does not purport to represent what the financial position or results of operations might be for any future period.

The following information should be read in conjunction with "Risk Factors", "Consolidated Capitalization", "Management's Discussion and Analysis of Financial Condition and Results of Operations", the consolidated financial statements of Hydro One Inc., and the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. and the related notes included elsewhere in this prospectus. The financial statements of Hydro One Inc. included in this prospectus have been prepared in accordance with U.S. GAAP.

	Six Months Ended June 30		
Statement of Operations Data[1]	**2015**	**2015**	**2014**
	(pro forma)		
	($, in millions)		
Revenues			
Distribution	2,320	2,574	2,497
Transmission	770	770	804
Other	27	27	29
Total revenues	3,117	3,371	3,330
Costs			
Purchased power	1,590	1,808	1,746
Operation, maintenance and administration	546	560	645
Depreciation and amortization	368	377	348
Total costs	2,504	2,745	2,739
Income before financing charges and provisions for payments in lieu of corporate income taxes	**613**	**626**	**591**
Financing charges	193	187	185
Provision for payments in lieu of corporate income taxes	64	68	51
Net income[3]	**356**	**371**	**355**

Statement of Operations Data(1)	Year ended December 31			
	2014 (pro forma)	2014	2013	2012
	($, in millions)			
Revenues				
Distribution	4,408	4,903	4,484	4,184
Transmission	1,588	1,588	1,529	1,482
Other	57	57	61	62
Total revenues	6,053	6,548	6,074	5,728
Costs				
Purchased power	2,993	3,419	3,020	2,774
Operation, maintenance and administration	1,165	1,192	1,106	1,071
Depreciation and amortization	708	722	676	659
Total costs	4,866	5,333	4,802	4,504
Income before financing charges and provisions for payments in lieu of corporate income taxes	**1,187**	**1,215**	**1,272**	**1,224**
Financing charges	392	379	360	358
Provision for payments in lieu of corporate income taxes	87	89	109	121
Net income(4)(5)	708	747	803	745

Selected Balance Sheet Data(1)(2)	As at June 30		As at December 31		
	2015 (pro forma)	2015	2014	2013	2012
	($, in millions)				
Total assets	23,871	23,167	22,550	21,625	20,811
Long-term debt (including current portion)	10,090	9,290	8,925	9,057	8,479

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See “Pre-Closing Transactions” for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the historical summary data appearing in the table above include the assets, liabilities and results of operations of Hydro One Brampton Networks Inc. during the periods and as at the dates indicated, except in the columns marked as “pro forma”.

(2) Prior to the closing of this offering, Hydro One Limited will issue $418 million of Series 1 preferred shares to the Province at a price of $25.00 per share. The existing preferred shares of Hydro One Inc. held by the Province will be cancelled. The initial dividend amount on the Series 1 preferred shares will be $1.0625 per share per year, and the dividend rate will be reset every five years in accordance with the terms of such shares. See “Description of Share Capital – Preferred Shares”.

(3) Net income presented is before the payment of dividends on preferred shares of Hydro One Inc. and prior to net income (loss) attributable to noncontrolling interest. Net income is therefore not equivalent to net income attributable to common shareholders. Dividends on preferred shares of Hydro One Inc. were $9 million for each of the six months ended June 30, 2015 and 2014. Net income attributable to noncontrolling interest for the six months ended June 30, 2015 was $3 million and for the six months ended June 30, 2014 was nil.

(4) Net income presented is before the payment of dividends on preferred shares of Hydro One Inc. and prior to net income (loss) attributable to noncontrolling interest. Net income is therefore not equivalent to net income attributable to common shareholders. Dividends on preferred shares of Hydro One Inc. were $18 million for each of the years ended December 31, 2014, 2013 and 2012. Net loss attributable to noncontrolling interest for the year ended December 31, 2014 was $2 million and for each of the years ended December 31, 2013 and 2012 were nil.

(5) Pro forma net income of Hydro One Inc. for the year ended December 31, 2014 reflects an estimated deferred tax asset adjustment arising as a result of Hydro One leaving the PILs regime and entering the corporate tax regime. See “Departure Tax”. This estimated deferred tax asset adjustment was based on an estimated fair market value of Hydro One’s net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion payable by Hydro One as referred to in “Departure Tax”. This estimated fair market value of Hydro One’s net assets was determined by Hydro One principally using a discounted cash flow approach for certain assets and an asset-based approach for other assets, and was used in calculating the amount of the departure tax payable that was agreed between Hydro One and the Province in early September 2015. The actual amount of the deferred tax asset for the year ended December 31, 2015 will be based on the actual fair market value of Hydro One’s net assets, which will be determined following pricing of this offering. The departure tax payable by Hydro One has been fixed at $2.6 billion, and will not be adjusted based on the fair market value of Hydro One’s net assets as finally determined. Net income for the year ended December 31, 2015 will reflect the payment of the departure tax and recognition of the actual amount of the deferred tax asset, which may be different from the recognition of the estimated deferred tax asset reflected in pro forma net income of Hydro One Inc. for the year ended December 31, 2014. As a result, net income for the year ended December 31, 2015 may be impacted by the difference, if any, between the actual and estimated fair market value of Hydro One’s net assets. Any impact on net income as a result of such difference will be non-cash-related and will only impact net income for the year ended December 31, 2015 and not subsequent years. The Company estimates that a $1,000 million increase or decrease in the fair market value of Hydro One’s net assets would result in a corresponding increase or decrease in the deferred tax asset, and therefore net income, of approximately $200 million.

Other Financial Measures(1)	Six months ended June 30		Year ended December 31		
	2015	2014	2014	2013	2012
	($, in millions)				
Reconciliation of net income to adjusted net income					
Net income	371	355	747	803	745
Adjustments	—	—	—	—	—
Adjusted net income(2)	**371**	**355**	**747**	**803**	**745**
Reconciliation of net cash from operating activities to FFO					
Net cash from operating activities	713	334	1,256	1,404	1,294
Change in non-cash operating working capital	59	304	55	(11)	31
Preferred dividends	(9)	(9)	(18)	(18)	(18)
Noncontrolling interest distributions(3)	(2)	—	—	—	—
FFO(2)(4)	**761**	**629**	**1,293**	**1,375**	**1,307**

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the other financial measures appearing in the table above include amounts contributed by Hydro One Brampton Networks Inc. during the periods indicated.

(2) Adjusted net income and FFO are non-GAAP measures. See "Non-GAAP Measures".

(3) In 2014, there was a $72 million noncontrolling interest contribution. This was a one-time item, and has been excluded from the calculation of FFO in 2014.

(4) FFO, as shown, has been calculated based on the historical financial information of Hydro One Inc. and does not reflect any of the pro forma adjustments set out in the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, including the net pro forma reduction in cash tax of $56 million for the year ended December 31, 2014 and $49 million for the six month period ended June 30, 2015. See note 2C(vi) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus.

Operating Statistics and Other Information (Including Hydro One Brampton Networks Inc. except where noted)(1)	Year Ended December 31		
	2014	2013	2012
Transmission			
Electricity transmitted (TWh)	139.8	140.7	141.3
Total transmission lines spanning the province (circuit-kilometres)	29,344	29,344	29,327
Rate base(2) ($ millions)	9,934	9,353	8,774
Capital investments ($ millions)(5)	845	714	776
Distribution			
Electricity distributed to Hydro One customers (TWh)	29.8	29.8	29.2
Electricity distributed through Hydro One lines (TWh)	42.4	42.5	42.4
Total distribution lines spanning the province (circuit kilometres)	123,657	122,853	121,525
Distribution customers (Hydro One Networks Inc.)(4)	1,268,745	1,270,817	1,236,526
Distribution customers (Hydro One Brampton Networks Inc.)	149,681	146,039	141,860
Rate base(2) ($ millions)	6,315	5,925	5,550
Capital investments ($ millions)(5)	680	673	671
Certain Operating Statistics for Hydro One Brampton Networks Inc.(3)			
Total distribution lines (circuit kilometres)	3,242	3,104	2,952
Distribution customers	149,681	146,039	141,860

Notes:

(1) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions. Hydro One Brampton Networks Inc. was previously a wholly-owned subsidiary of Hydro One Inc. Because this transfer occurred after the dates of, and periods covered by, the historical consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, those financial statements and the summary operating statistics appearing in the table above include amounts contributed by Hydro One Brampton Networks Inc. during the periods indicated.

(2) Rate base in each year refers to the rate base of Hydro One Networks Inc.'s transmission business or distribution business, as the case may be, approved by the Ontario Energy Board for that year. See "Meaning of Certain References".

(3) On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to a company wholly-owned by the Province. See "Pre-Closing Transactions" for additional detail concerning the transfer and related transactions.

(4) Includes certain classes of customers which are excluded in the *Ontario Energy Board Yearbook of Distributors* (2014).

(5) Capital investments consists of capital expenditures presented in Hydro One's consolidated statement of cash flows, adjusted for capitalized depreciation, if any, and net changes in related accruals.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Hydro One Limited was incorporated on August 31, 2015. It has not completed its first fiscal year and has had limited activity. Prior to the completion of this offering, Hydro One Inc. will become a wholly-owned subsidiary of Hydro One Limited. See "Pre-Closing Transactions".

This management's discussion and analysis of financial condition and results of operations ("**MD&A**") has been prepared with respect to Hydro One Inc. (the "**Company**" or "**Hydro One**"). In this MD&A only, references to the "Company" or "Hydro One" refer to Hydro One Inc. and its consolidated subsidiaries, and do not include or refer to Hydro One Limited and references to "Shareholder" refer to the Province of Ontario.

This MD&A should be read in conjunction with the consolidated financial statements and accompanying notes of Hydro One that appear elsewhere in this prospectus. Those financial statements consist of the unaudited interim financial statements of Hydro One for the three and six month periods ended June 30, 2015 and the balance sheet as at June 30, 2015 and December 31, 2014, the audited consolidated financial statements of Hydro One as at and for the years ended December 31, 2014 and 2013, and the audited consolidated financial statements of Hydro One as at and for the years ended December 31, 2013 and 2012, in each case, together with the notes accompanying such financial statements.

On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred from Hydro One Inc. to a company wholly owned by the Province, as described in "Pre-Closing Transactions". Hydro One Brampton Networks Inc. was previously a wholly owned subsidiary of Hydro One. Because this transfer occurred after the dates of, and periods covered by, the consolidated financial statements of Hydro One appearing elsewhere in this prospectus, those financial statements and the summary consolidated financial information derived from those financial statements include the assets, liabilities and results of operations of Hydro One Brampton Networks Inc. **Accordingly, all financial information of Hydro One referred to or discussed in this MD&A includes the assets, liabilities and results of operations of Hydro One Brampton Networks Inc. To see the impact of certain transactions related to the offering on the financial statements of Hydro One Inc., including the transfer of all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly owned by the Province, see the unaudited pro forma condensed consolidated financial statements of Hydro One Inc., together with "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information" elsewhere in this prospectus.**

The Company's consolidated financial statements are presented in Canadian dollars and have been prepared in accordance with U.S. GAAP. The Ontario Energy Board approved the use of U.S. GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks Inc.'s ("**Hydro One Networks**") transmission and distribution businesses, as well as by Hydro One Remote Communities Inc., beginning with the 2012 financial year. Hydro One Networks and Hydro One Remote Communities Inc. are wholly owned subsidiaries of Hydro One. During the periods presented, Hydro One Brampton Networks Inc. used Canadian GAAP (Part V) for its distribution rate-setting purposes.

All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

Some of the information contained in this MD&A contains forward-looking information that involves risks and uncertainties. See "Forward-Looking Information" and "Risk Factors" for a discussion of the uncertainties and assumptions associated with these statements. Actual results may differ materially from those indicated or underlying forward-looking information as a result of various factors, including those described under "Risk Factors" and elsewhere in this MD&A.

Overview

Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business (primarily telecommunications).

Hydro One's transmission business consists of owning, operating and maintaining Hydro One's transmission system, which accounts for 96% of Ontario's entire transmission network based on revenue approved by the Ontario

Energy Board. This includes the Company's 66% ownership interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. All of the Company's transmission business is carried out by Hydro One Networks, except for the portion of its business held through B2M Limited Partnership, which the Company controls and operates.

Hydro One's distribution business consists of owning, operating and maintaining Hydro One's distribution system, which the Company owns primarily through Hydro One Networks, the largest local distribution company in Ontario. The Company's distribution system is also the largest in Ontario, spanning approximately 75% of the geographic area of the province. Hydro One's distribution business also includes the business of Hydro One Remote Communities Inc., which supplies electricity to customers in remote communities in northern Ontario, as well as the distribution businesses of Norfolk Power and Haldimand Hydro.

Hydro One's other business segment principally consists of its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, and also markets and sells fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The telecommunications business is carried out by the Company's wholly-owned subsidiary, Hydro One Telecom Inc.

Summary of Results for Three and Six Month Periods

Consolidated Statements of Operations and Comprehensive Income	Three months ended June 30		Six months ended June 30	
	2015	2014	2015	2014
	(millions of Canadian dollars, except per share amounts)			
Total revenue	1,563	1,566	3,371	3,330
Net income attributable to Shareholder of Hydro One	136	115	368	355
Earnings per common share *(Canadian dollars)*	1,308	1,099	3,594	3,456
Dividends per common share *(Canadian dollars)*	250	250	500	2,196
Dividends per preferred share *(Canadian dollars)*	0.34	0.34	0.69	0.69

Consolidated Balance Sheets	June 30, 2015	December 31, 2014
	(millions of Canadian dollars)	
Total assets	23,167	22,550
Total long-term debt	9,290	8,925
Preferred shares	323	323
Net assets	8,257	7,947

During the six months ended June 30, 2015, Hydro One earned net income of $368 million and revenues of $3,371 million. The Company made capital investments totalling $774 million to improve its transmission and distribution systems' reliability and performance, address its aging power system infrastructure, facilitate new generation, and improve service to its customers.

Developments in 2015

Change in Credit Ratings

On April 17, 2015, Moody's Investors Service (Moody's) affirmed the senior unsecured ratings of Hydro One at A1 but revised its outlook on the Company to negative from stable. On September 18, 2015, Moody's downgraded the senior unsecured ratings of Hydro One to A2 from A1, and maintained its outlook on the Company as negative. Moody's noted that the negative outlook reflects the high probability of a further downgrade to A3 following this offering. Moody's also stated that a downgrade to A3 would lead to a downgrade of Hydro One's short-term debt rating to Prime-2.

On April 20, 2015, Standard & Poor's Rating Services Inc. (S&P) downgraded its long-term corporate credit rating on Hydro One to A from A+, and revised its outlook on the Company to stable from negative. On September 18, 2015, S&P affirmed its long-term corporate credit rating on Hydro One of A (stable).

On September 18, 2015, DBRS Limited (DBRS) placed Hydro One's issuer rating and senior unsecured debentures rating "under review with developing implications" and placed its short-term debt rating "under review with negative implications".

The Moody's and S&P ratings changes and actions were related to the announcement by the Province that it intended to dispose of up to 15% of its shares in Hydro One via an initial public offering, and the subsequent filing of a preliminary base PREP prospectus of Hydro One Limited dated September 17, 2015 relating to this offering. The action taken by DBRS followed the filing of the preliminary base PREP prospectus of Hydro One Limited dated September 17, 2015 relating to this offering in anticipation of the impact of certain of the transactions disclosed in "Pre-Closing Transactions".

A summary of the Company's corporate credit ratings can be found in the section "Liquidity and Capital Resources for Three and Six Month Periods – Financing Activities" in this MD&A and under "Credit Ratings of Securities."

Haldimand Hydro Acquisition

In June 2015, Hydro One acquired 100% of the common shares of Haldimand Hydro, an electricity distribution company located in southwestern Ontario, following approval of the acquisition by the Ontario Energy Board in March 2015. The Haldimand Hydro acquisition is part of the Company's local distribution company consolidation strategy to better serve Ontario's distribution system and improve system reliability and efficiency across the grid. Hydro One is committed to delivering reliable service for Haldimand Hydro's customers and improving efficiencies in both the Haldimand Hydro and Hydro One systems as a result of the acquisition. The purchase price for Haldimand Hydro was approximately $65 million, subject to final closing adjustments. Closing adjustments to the purchase price and the final allocation of the consideration paid are expected to be completed by the end of 2015.

Class Action Lawsuit

On July 22, 2015, two Toronto law firms issued a joint press release announcing that a $125 million lawsuit had been commenced in the Ontario Superior Court of Justice against Hydro One and four of its subsidiaries. The statement of claim dated September 9, 2015 alleges improper billing and account management practices. The action is proposed as a class action. This claim is in a very early stage and has not been certified as a class action. It is too early to assess the merits of the claim. Hydro One intends to defend the action.

Outlook

The following is a discussion of certain factors that have impacted or are anticipated to impact the Company's results of operations in 2015, as well as certain events that occurred in 2014 that may impact the comparability of the Company's results of operations for 2015 and interim periods during 2015.

- The Company continues to benefit from increased transmission and distribution rates in 2015 as a result of the Company's most recent transmission and distribution rate decisions.
- During the first half of 2015, operation, maintenance and administration costs relative to the same period in 2014 were lower due to the stabilization of the Company's customer information system and the acceleration of collections on aged accounts receivable. These costs declined significantly in the fourth quarter of 2014, partially offsetting a large portion of the increased costs earlier in the year. These in-year timing differences combined with certain other reductions resulted in lower overall operation, maintenance and administration costs in the fourth quarter of 2014 compared to the preceding three quarters. These costs have returned to a more normalized level and are more equally spread over the course of 2015.
- During 2014, the Company's results of operations were positively affected by increased system usage and transmission load due to weather conditions. These positive impacts may not recur during 2015.
- As part of its settlement of 2013 and 2014 transmission rates, the Company is subject to a revenue clawback intended to account for the difference between actual and forecast load attributable to any shortfalls in the forecasted province-wide conservation and demand management or "CDM" savings. The Company is obligated to transfer to a variance account the amount of transmission revenues that reflects the impact on the Company's revenue requirement of actual province-wide CDM savings versus the forecast province-wide CDM savings for those years. The amount to be transferred for 2014 is $27.8 million. The impact was recorded in the third quarter of 2015.
- During the fourth quarter of 2015, the Company is anticipated to incur costs related to the granting of shares to certain unionized employees pursuant to the share grant plans to be established for the benefit of certain employees represented by the Power Workers' Union and The Society of Energy Professionals, as described in "Share Grant Plans". These costs are anticipated to result in a non-cash charge to net income of approximately $8 million, which would be included in operation, maintenance and administration costs.

- As a result of Hydro One leaving the PILs regime and entering the corporate tax regime, Hydro One will recognize a deferred tax asset that is currently estimated in the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus to be $1,245 million due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. See "Departure Tax". This estimated deferred tax asset adjustment was based on an estimated fair market value of Hydro One's net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion payable by Hydro One as referred to in "Departure Tax". The actual amount of the deferred tax asset for the year ended December 31, 2015 will be based on the actual fair market value of Hydro One's net assets, which will be determined following pricing of this offering. Net income for the year ended December 31, 2015 may be impacted by the difference, if any, between the actual and estimated fair market value of Hydro One's net assets, since this difference will impact the actual amount of the deferred tax asset. Any impact on net income as a result of such difference will be non-cash-related and will only impact net income for the year ended December 31, 2015 and not subsequent years. The Company estimates that a $1,000 million increase or decrease in the fair market value of Hydro One's net assets would result in a corresponding increase or decrease in the deferred tax asset, and therefore net income, of approximately $200 million. See "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information".
- In the third and fourth quarters of 2014, Hydro One recognized in net income non-recurring insurance proceeds of $11 million related to 2013 floods at the Company's Richview and Manby transformer stations.
- During 2014, the Company realized an effective tax rate of approximately 10%. For the six months ended June 30, 2015, the Company realized an effective tax rate of approximately 16% and anticipates an effective tax rate of approximately 15% for the remainder of 2015. The difference in the effective tax rate between 2014 and 2015 is due primarily to accelerated capital cost allowance recognized in 2014 for certain classes of assets.
- The transfer of Hydro One Brampton Networks Inc. as described in "Pre-Closing Transactions" is expected to have a non-material effect on net income in 2015, but will more significantly impact distribution revenues and purchased power costs.

In addition to the factors described above, see the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. and the related notes included elsewhere in this prospectus which give effect to certain transactions described in the notes to those statements for the periods shown, including the transfer of Hydro One Brampton Networks Inc.

Applications to the Ontario Energy Board

The following table summarizes Hydro One's recent major regulatory applications to the Ontario Energy Board:

Application	Year(s)	Type	Date Filed	Status
Electricity Rates – Transmission Rate Applications				
Hydro One Networks	2015-2016	Cost-of-service	September 16, 2014	Decision received on January 8, 2015
B2M Limited Partnership	2015	Interim	October 24, 2014	Decision received on December 11, 2014
B2M Limited Partnership	2015-2019	Cost-of-service	March 30, 2015	Decision anticipated in 2015
Electricity Rates – Distribution Rate Applications				
Hydro One Networks	2015-2017	Custom	December 19, 2013	Decision received on March 12, 2015(1)
Hydro One Brampton Networks Inc.	2015	Cost-of-service	April 23, 2014	Decision received on January 15, 2015
Hydro One Remote Communities Inc.	2015	IRM	September 24, 2014	Decision received on March 19, 2015
Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications				
Woodstock Hydro	n/a	Acquisition	July 9, 2014	Decision received on September 11, 2015
Leave to Construct Application				
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	January 22, 2014	Decision for Phase 1 received on July 16, 2015 Decision for Phase 2 anticipated in late 2015

(1) The application filed by Hydro One Networks on December 19, 2013 was for years 2015-2019. On March 12, 2015, the Ontario Energy Board issued a Decision and Rate Order for years 2015-2017 only. See "Business of Hydro One – Distribution Business – Regulation."

Factors Affecting Results of Operations

Transmission Revenues

Transmission revenues primarily consist of the Company's transmission rates approved by the Ontario Energy Board, which are based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum forecasted demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of the Company's land rights.

Distribution Revenues

Distribution revenues include the distribution rates approved by the Ontario Energy Board and amounts to recover the cost of purchased power used by the customers of the distribution business. Accordingly, distribution revenues are influenced by the amount of electricity the Company distributes, the cost of purchased power and distribution rates. Distribution revenues also include minor ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of purchased electricity delivered to customers within Hydro One's distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the Ontario Energy Board's regulated price plan or the market price for electricity. Except for short-term timing differences, Hydro One recovers the cost of electricity that it delivers, and is therefore not financially exposed to commodity price risk related to electricity.

Operation, Maintenance and Administration Costs

Operation, maintenance and administration costs include work program costs and costs to support the operation and maintenance of the transmission and distribution systems. Also included in these costs are payments in lieu of property taxes related to the transmission and distribution lines, stations and buildings. The transmission operation, maintenance and administration costs are incurred to sustain the Company's high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and brush control. The distribution operation, maintenance and administration costs are required to maintain the Company's low-voltage distribution system, and include costs related to distribution line clearing and brush control, line maintenance and repair, as well as land assessment and remediation. Hydro One continues to focus on managing its costs, while continuing to complete its planned work programs for both its transmission and distribution businesses.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation and amortization of the Company's property, plant and equipment, intangible assets and certain regulatory assets. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt, gains and losses on interest rate swap agreements, interest earned on short-term and long-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment.

Payments in Lieu of Corporate Income Taxes

Generally, Hydro One Inc. and its subsidiaries have been exempt from regular federal and Ontario income tax and instead paid an equivalent amount referred to as payments in lieu of corporate income taxes or "PILs" to the Ontario Electricity Financial Corporation under the Electricity Act. Once Hydro One is less than 90% owned by the Province, it will cease to be exempt from regular federal and Ontario income tax, and will be deemed, for purposes of the Tax Act, to have disposed of its assets before it loses its tax-exempt status for proceeds equal to the fair market value of those assets at that time, and will be deemed to have acquired all such assets at the time of the loss of tax-exempt status at a cost equal to fair market value. See "Departure Tax".

Results of Operations – Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

Three months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Revenues	1,563	1,566	(3)	(0.2)
Purchased power	838	824	14	1.7
Operation, maintenance and administration	282	334	(52)	(15.6)
Depreciation and amortization	190	181	9	5.0
	1,310	1,339	(29)	(2.2)
Income before financing charges and provision for PILs	**253**	**227**	**26**	**11.5**
Financing charges	93	95	(2)	(2.1)
Income before provision for PILs	**160**	**132**	**28**	**21.2**
Provision for PILs	23	17	6	35.3
Net income	**137**	**115**	**22**	**19.1**
Net income (loss) attributable to noncontrolling interest	1	—	1	100.0
Net income attributable to Shareholder of Hydro One	**136**	**115**	**21**	**18.3**

Net Income

The net income attributable to the Shareholder of Hydro One for the three months ended June 30, 2015 was $136 million, compared to $115 million during the same period in 2014, an increase of $21 million or 18.3%. The increase is primarily due to the following:

- a decrease in operation, maintenance and administration costs, primarily resulting from lower expenditures related to the Company's Customer Information System ("**CIS**"); lower bad debt expense resulting from the reinstatement of certain collection activities in September 2014; lower expenditures associated with responding to and restoring power outages; and decreased vegetation management requirements for brush control programs; partially offset by
- a decrease in transmission revenues, mainly due to lower average Ontario 60-minute peak demand in the second quarter of 2015, as the weather in the quarter was milder than last year, and
- an increase in depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense related to growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital work programs.

Revenues

Three months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	364	382	(18)	(4.7)
Distribution	1,185	1,170	15	1.3
Other	14	14	—	—
	1,563	1,566	(3)	(0.2)
Average annual Ontario 60-minute peak demand (MW)[(1)]	18,986	19,403	(417)	(2.1)
Distribution – units distributed to Hydro One customers (TWh)[(1)]	6.7	6.7	—	—

(1) System-related statistics are preliminary.

Transmission

Transmission revenues for the three months ended June 30, 2015 were $364 million, compared to $382 million during the same period in 2014, a decrease of $18 million or 4.7%. The components of the decrease include the following:

- lower average Ontario 60-minute peak demand in the second quarter of 2015, as peak demand towards the end of the quarter did not reach the Company's forecast, as weather patterns during the quarter and extending into the third quarter have been milder than 2014, and

- disposition of certain Ontario Energy Board-approved transmission regulatory accounts; partially offset by
- higher new transmission rates effective January 1, 2015 approved by the Ontario Energy Board in January 2015.

Distribution

Distribution revenues for the three months ended June 30, 2015 were $1,185 million, compared to $1,170 million during the same period in 2014, an increase of $15 million or 1.3%. The components of the increase include the following:

- higher purchased power costs, as described below under "Purchased Power Costs", and
- higher new distribution rates effective January 1, 2015 approved by the Ontario Energy Board in March 2015; partially offset by
- the expiry of certain Ontario Energy Board-approved rate riders and regulatory accounts.

Purchased Power Costs

Purchased power costs for the three months ended June 30, 2015 were $838 million, compared to $824 million during the same period in 2014, an increase of $14 million or 1.7%. The components of the increase include the following:

- higher Ontario Energy Board Regulated Price Plan rates for residential and other eligible customers, and
- higher purchased power costs for customers who are not eligible for the Regulated Price Plan; partially offset by
- lower demand for electricity in the second quarter of 2015, , as the weather in the quarter was milder than last year; and
- lower wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration Costs

Three months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	98	105	(7)	(6.7)
Distribution	168	214	(46)	(21.5)
Other	16	15	1	6.7
	282	334	(52)	(15.6)

Transmission

Transmission operation, maintenance and administration costs for the three months ended June 30, 2015 were $98 million, compared to $105 million during the same period in 2014, a decrease of $7 million or 6.7%. The components of the decrease include the following:

- decreased forestry expenditures related to brush control and line clearing on the Company's transmission rights-of-way, and
- lower volume of corrective maintenance work required on overhead lines; partially offset by
- higher expenditures related to compliance with NERC Critical Infrastructure Protection ("**Cyber Security**") standards. See "Business of Hydro One – Transmission Business – Regulation".

Distribution

Distribution operation, maintenance and administration costs for the three months ended June 30, 2015 were $168 million, compared to $214 million during the same period in 2014, a decrease of $46 million or 21.5%. The components of the decrease include the following:

- lower expenditures related to the CIS system, as remediation of issues related to the installation of the system is completed, and the system is now stable,

- decrease in bad debt expense, resulting from the reinstatement of certain collection activities in September 2014, which were temporarily suspended during several months in 2014 due to system issues, as Hydro One has made improvements in its customer service during 2015, restored service levels at its call centre, and restored its billing system performance, which has enabled more active collections of overdue balances,
- decreased vegetation management requirements for the brush control program,
- lower expenditures associated with locating and restoring power outages, as well as responding to power quality-related issues, and
- lower volume of work on the land assessment and remediation program to assess the degree of environmental contamination at Hydro One's owned stations and facilities.

Financing Charges

Financing charges for the three months ended June 30, 2015 were $93 million, compared to $95 million during the same period in 2014, a decrease of $2 million or 2.1%. The decrease is primarily due to an increase in capitalized interest, resulting from higher average property, plant and equipment construction in progress balances eligible for interest capitalization.

Provision for PILs

The provision for PILs for the three months ended June 30, 2015 was $23 million, compared to $17 million during the same period in 2014, an increase of $6 million or 35.3%. The increase is primarily due to higher pre-tax income.

Results of Operations – Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Revenues	3,371	3,330	41	1.2
Purchased power	1,808	1,746	62	3.6
Operation, maintenance and administration	560	645	(85)	(13.2)
Depreciation and amortization	377	348	29	8.3
	2,745	2,739	6	0.2
Income before financing charges and provision for PILs	**626**	**591**	**35**	**5.9**
Financing charges	187	185	2	1.1
Income before provision for PILs	**439**	**406**	**33**	**8.1**
Provision for PILs	68	51	17	33.3
Net income	**371**	**355**	**16**	**4.5**
Net income (loss) attributable to noncontrolling interest	3	—	3	100.0
Net income attributable to Shareholder of Hydro One	**368**	**355**	**13**	**3.7**

Net Income

Net income attributable to the Shareholder of Hydro One for the six months ended June 30, 2015 was $368 million, compared to $355 million during the same period in 2014, an increase of $13 million or 3.7%. The increase is primarily due to the following:

- a decrease in operation, maintenance and administration costs, primarily resulting from lower expenditures related to the Company's CIS; lower bad debt expense resulting from the reinstatement of certain collection activities in September 2014; lower expenditures associated with responding to and restoring power outages; and lower volume of work on the land assessment and remediation program,
- an increase in distribution revenues, mainly due to higher new Ontario Energy Board-approved 2015 distribution rates, partially offset by the expiry of certain Ontario Energy Board-approved rate riders and regulatory accounts,

- a decrease in transmission revenues, mainly due to lower average Ontario 60-minute peak demand in the first half of 2015, as well as the disposition of certain Ontario Energy Board-approved regulatory accounts, partially offset by an increase due to higher new Ontario Energy Board-approved 2015 transmission rates, and
- an increase in depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense, related to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital work programs.

Revenues

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	770	804	(34)	(4.2)
Distribution	2,574	2,497	77	3.1
Other	27	29	(2)	(6.9)
	3,371	3,330	41	1.2
Average annual Ontario 60-minute peak demand (MW)(1)	20,182	20,757	(575)	(2.8)
Distribution – units distributed to Hydro One customers (TWh)(1)	15.4	15.4	—	—

(1) System-related statistics are preliminary.

Transmission

Transmission revenues for the six months ended June 30, 2015 were $770 million, compared to $804 million during the same period in 2014, a decrease of $34 million or 4.2%. The components of the decrease include the following:

- lower average Ontario 60-minute peak demand in the first six months of 2015, partially due to industrial customers shifting their energy use away from system-wide peaks in the winter months of 2015, as well as milder weather in 2015, compared to the same period in 2014, and
- disposition of certain Ontario Energy Board-approved transmission regulatory accounts; partially offset by
- higher new transmission rates effective January 1, 2015 approved by the Ontario Energy Board in January 2015.

Distribution

Distribution revenues for the six months ended June 30, 2015 were $2,574 million, compared to $2,497 million during the same period in 2014, an increase of $77 million or 3.1%. The components of the increase include the following:

- higher purchased power costs, as described below under "Purchased Power Costs", and
- higher new distribution rates effective January 1, 2015 approved by the Ontario Energy Board in March 2015; partially offset by
- the expiry of certain Ontario Energy Board-approved rate riders and regulatory accounts.

Purchased Power Costs

Purchased power costs for the six months ended June 30, 2015 were $1,808 million, compared to $1,746 million during the same period in 2014, an increase of $62 million or 3.6%. The components of the increase include the following:

- higher Ontario Energy Board Regulated Price Plan rates for residential and other eligible customers, and
- higher purchased power costs for customers who are not eligible for the Regulated Price Plan; partially offset by

- lower demand for electricity in the first six months of 2015, mainly resulting from milder weather in 2015, and
- lower wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	197	220	(23)	(10.5)
Distribution	334	395	(61)	(15.4)
Other	29	30	(1)	(3.3)
	560	645	(85)	(13.2)

Transmission

Transmission operation, maintenance and administration costs for the six months ended June 30, 2015 were $197 million, compared to $220 million during the same period in 2014, a decrease of $23 million or 10.5%. The components of the decrease include the following:

- decreased forestry expenditures related to brush control and line clearing on the Company's transmission rights-of-way,
- lower volume of corrective maintenance work required on overhead lines,
- decreased requirements related to corrective maintenance work for mineral oil spills,
- increased attribution of overheads to capital project expenditures reflecting the higher expenditures related to capital projects in the first half of 2015, and
- cost savings reflecting various management initiatives to reduce overhead costs; partially offset by
- higher expenditures related to compliance with NERC's Cyber Security standards. See "Business of Hydro One – Transmission Business – Regulation".

Distribution

Distribution operation, maintenance and administration costs for the six months ended June 30, 2015 were $334 million, compared to $395 million during the same period in 2014, a decrease of $61 million or 15.4%. The components of the decrease include the following:

- lower expenditures related to the Company's CIS, as remediation of issues related to the installation of the system was completed, and the system is now stable,
- decrease in bad debt expense, resulting from the reinstatement of certain collection activities in September 2014, which were temporarily suspended during several months in 2014 due to system issues,
- lower volume of work associated with locating and restoring power outages, responding to and resolving power quality customer complaints, identifying and correcting abnormal system conditions, as well as responding to power quality-related issues and outages as a result of lower storm activity and enhanced response times, and
- lower volume of work on the land assessment and remediation program to assess the degree of environmental contamination at Hydro One's owned stations and facilities; partially offset by
- increased volume of lines maintenance work to ensure long term sustainability of line assets and safety.

Depreciation and Amortization

Depreciation and amortization costs for the six months ended June 30, 2015 were $377 million, compared to $348 million during the same period in 2014, an increase of $29 million or 8.3%. The increase was primarily attributable to higher property, plant and equipment depreciation expense in the first half of 2015, mainly related to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital work program.

Financing Charges

Financing charges for the six months ended June 30, 2015 were $187 million, compared to $185 million during the same period in 2014, an increase of $2 million or 1.1%. The increase is primarily due to a decrease in interest earned on the Company's investment in Province of Ontario floating-rate notes which matured in November 2014.

Provision for PILs

The provision for PILs for the six months ended June 30, 2015 was $68 million, compared to $51 million during the same period in 2014, an increase of $17 million or 33.3%. The increase is primarily due to the following:

- higher pre-tax income, and
- changes in temporary differences, such as capital cost allowance in excess of depreciation.

Selected Financial Highlights and Ratios

	Three months ended June 30		Six months ended June 30	
	2015	2014	2015	2014
	(millions of Canadian dollars, except per share amounts and ratios)			
Net income attributable to Shareholder of Hydro One	136	115	368	355
Net cash from operating activities	287	185	713	334
Capital investments	429	380	774	676
Earnings per common share *(Canadian dollars)*	1,308	1,099	3,594	3,456

	June 30, 2015	December 31, 2014
Earnings coverage ratio[1]	2.79	2.81
Net assets coverage on long-term debt ratio[2]	1.89	1.89
Total debt to capitalization ratio[3]	53.2%	53.1%

(1) The earnings coverage ratio has been presented for the twelve months ended June 30, 2015 and June 30, 2014, and has been calculated as the sum of net income attributable to Shareholder of Hydro One, provision for PILs and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

(2) The net asset coverage on long-term debt ratio has been presented as at June 30, 2015 and December 31, 2014, and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

(3) Total debt to capitalization ratio has been presented as at June 30, 2015 and December 31, 2014, and has been calculated as total long-term debt divided by total long-term debt plus total shareholder's equity and preferred shares. This ratio is expected to be 51.1% immediately following the recapitalization referred to in "Pre-Closing Transactions" and the closing of this offering.

Liquidity and Capital Resources for Three and Six Months Periods

Hydro One's primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividends.

Summary of Sources and Uses of Cash

	Three months ended June 30		Six months ended June 30	
	2015	2014	2015	2014
	(millions of Canadian dollars)			
Operating activities	287	185	713	334
Financing activities				
Long-term debt issued	350	453	350	628
Dividends paid	(30)	(30)	(59)	(229)
Investing activities				
Capital expenditures	(422)	(367)	(766)	(659)
Net cash paid for Haldimand Hydro	(58)	—	(58)	—
Other financing and investing activities	(38)	17	(10)	—
Net change in cash and cash equivalents	89	258	170	74

Cash from Operating Activities

Three months ended June 30, 2015

Net cash from operating activities increased by $102 million to $287 million during the three months ended June 30, 2015, compared to the same period in 2014. The increase was primarily due to the following:

- changes in regulatory accounts, primarily due to the retail settlement and external revenue variance accounts,
- changes in accounts receivable balances, due to improved collections in 2015, and
- higher net income before taxes and depreciation; partially offset by
- changes in accrual balances, mainly related to timing and higher activity of capital projects.

Six months ended June 30, 2015

Net cash from operating activities increased by $379 million to $713 million during the six months ended June 30, 2015, compared to the same period in 2014. The increase was primarily due to the following:

- changes in accounts receivable balances, due to improved collections in 2015,
- changes in regulatory accounts, primarily due to the retail settlement and external revenue variance accounts,
- lower pension plan contributions compared to last year, as contributions are being made evenly over the year in 2015, compared to 2014, when payments were made in advance in the beginning of the year, and
- higher net income before taxes and depreciation; partially offset by
- changes in accrual balances, mainly related to timing and higher activity of capital projects.

Financing Activities

Short-term liquidity is provided through funds from operations, the Company's commercial paper program, and the Company's revolving credit facility.

At June 30, 2015, under the commercial paper program, Hydro One was authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. On October 9, 2015, Hydro One increased the amount it was authorized to issue under this program to $1.5 billion. The commercial paper program is supported by a $1.5 billion committed revolving credit facility with a syndicate of banks, which matures in June 2020. The short-term liquidity under this program and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At June 30, 2015, Hydro One had $9,289 million in long-term debt outstanding, including the current portion. The Company's notes and debentures mature between 2015 and 2064. Long-term financing is primarily provided by Hydro One's medium-term note program ("**MTN Program**"). The maximum authorized principal amount of medium-term notes issuable under this program is $3 billion. At June 30, 2015, $837 million remained available until October 2015. The Company plans to file a base shelf prospectus to renew its MTN Program for another 25 months by the end of 2015.

Hydro One relies on debt financing through its MTN Program and commercial paper program to repay its existing indebtedness and fund a portion of its capital expenditures. The credit ratings assigned to Hydro One's debt securities by external rating agencies are important to the Company's ability to raise low-cost capital and funding to support its business operations. Maintaining strong credit ratings allows Hydro One to access capital markets on competitive terms. A material downgrade of the Company's credit ratings would likely increase its cost of funding significantly, and its ability to access funding and capital through the capital markets could be reduced.

At June 30, 2015, Hydro One's corporate credit ratings from approved rating organizations were as follows:

	Rating *(at June 30, 2015)*	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited[(1)]	R-1 (middle)	A (high)
Moody's[(2)]	Prime-1	A1
S&P[(3)]	A-1	A

(1) On September 18, 2015, DBRS placed Hydro One's issuer rating and senior unsecured debentures rating "under review with developing implications" and placed its short-term debt rating "under review with negative implications".

(2) On April 17, 2015, Moody's affirmed the senior unsecured ratings of Hydro One at A1 but revised its outlook on the Company to negative from stable. On September 18, 2015, Moody's downgraded the senior unsecured ratings of Hydro One to A2 from A1, and maintained its outlook on the Company as negative. Moody's noted that the negative outlook reflects the high probability of a further downgrade to A3 following this offering. Moody's also stated that a downgrade to A3 would lead to a downgrade of Hydro One's short-term debt rating to Prime-2.

(3) On April 20, 2015, S&P downgraded the rating on Hydro One's long-term debt to A from A+, and revised its outlook to stable from negative. On September 18, 2015, S&P affirmed its long-term corporate credit rating on Hydro One of A (stable).

Hydro One is subject to customary covenants normally associated with long-term debt. The Company's long-term debt covenants limit its permissible debt as a percentage of its total capitalization, limit the Company's ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by Hydro One's subsidiaries cannot exceed 10% of the total book value of the Company's assets. Hydro One was in compliance with all of these and other covenants and limitations as at June 30, 2015.

Three months ended June 30, 2015

During the three months ended June 30, 2015, Hydro One issued $350 million of long-term debt under its MTN Program, and assumed $16 million of debt as part of the Haldimand Hydro acquisition, compared to $453 million of long-term debt issued during the same period in 2014. No long-term debt matured or was repaid during the three months ended June 30, 2015 or 2014. The Haldimand Hydro debt was repaid in July 2015.

During the three months ended June 30, 2015, Hydro One paid dividends to the Province in the amount of $30 million, consisting of $25 million of common share dividends and $5 million of preferred share dividends, consistent with dividends paid to the Province during the same period in 2014.

Six months ended June 30, 2015

During the six months ended June 30, 2015, Hydro One issued $350 million of long-term debt under its MTN Program, and assumed $16 million of debt as part of the Haldimand Hydro acquisition, compared to $628 million of long-term debt issued during the same period in 2014. No long-term debt matured or was repaid during the six months ended June 30, 2015 or 2014. The Haldimand Hydro debt was repaid in July 2015.

During the six months ended June 30, 2015, Hydro One paid dividends to the Province in the amount of $59 million, consisting of $50 million of common share dividends and $9 million of preferred share dividends, compared to dividends of $229 million, consisting of $220 million of common share dividends and $9 million of preferred share dividends, paid to the Province during the same period in 2014.

Investing Activities

During the six months ended June 30, 2015, Hydro One continued to focus on making important investments in its transmission and distribution systems to address its aging power system infrastructure, improve system reliability and performance, and improve service to its customers. During the six months ended June 30, 2015, the Company made capital investments totalling $774 million and placed $531 million of new assets in-service, compared to $676 million of capital investments and $533 million of new assets placed in-service during the same period in 2014.

The Company's current transmission sustainment programs include transformers, circuit breakers, switches, protection and control systems, wood poles, and other equipment replacements. Current transmission development projects include transmission system upgrades, local area supply projects, and inter-area network projects. These investments will expand and reinforce power reliability for electricity customers throughout the province, including the Company's residential and industrial customers.

The Company's current distribution sustainment programs include wood pole and meter replacements, emergency work for storm restoration, distribution station refurbishments and upgrades, and work related to joint-use and relocation of its distribution lines. Current development projects to expand and reinforce the Company's distribution network include new customer connections and upgrades, system capability reinforcement projects, line transfers requested by customers, and connections to new generation facilities.

The following table presents Hydro One's capital investments by reportable segment during the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30		Six months ended June 30	
	2015	2014	2015	2014
	(millions of Canadian dollars)			
Transmission	234	203	445	376
Distribution	192	175	324	298
Other	3	2	5	2
Total capital investments	429	380	774	676

Three months ended June 30, 2015

Three months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	234	203	31	15.3
Distribution	192	175	17	9.7
Other	3	2	1	50.0
Total capital investments	429	380	49	12.9

Transmission Capital Investments

The following table presents the main components of the Company's transmission capital investments during the three months ended June 30, 2015 and 2014:

Three months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Sustainment	193	167	26	15.6
Development	40	26	14	53.8
Other	1	10	(9)	(90.0)
Total transmission capital investments	234	203	31	15.3

Transmission Sustainment Capital Investments

During the three months ended June 30, 2015, Hydro One's transmission sustainment capital investments were $193 million, compared to $167 million during the same period in 2014, an increase of $26 million or 15.6%. The increase was mainly due to the following:

- system re-investments, and end-of-life equipment replacement work at several transmission stations, including the Bruce, Richview, and Wiltshire Transmission Stations, as well as the completion of refurbishments of the Dunnville Transmission Station,
- increased volume of work related to station security upgrades to prevent unauthorized entry to stations and enhance safety, and increased cyber system replacements to adhere to NERC's Cyber Security standards,
- increased work on overhead lines refurbishment and replacement projects and programs, and
- increased volume of transformer purchases for the Company's station demand and spares program to ensure readiness for unplanned replacements; partially offset by
- decreased expenditures related to underground lines system replacements, as the end-of-life underground transmission cables between the Strachan Transformer Station and Riverside Junction, which were originally planned for a 2015 in-service date, were replaced earlier and put in-service in 2014.

Transmission Development Capital Investments

During the three months ended June 30, 2015, Hydro One's transmission capital investments to expand and reinforce its transmission system were $40 million, compared to $26 million during the same period in 2014, an increase of $14 million or 53.8%. The increase was mainly due to the following:

- the timing of work on some of the Company's major inter-area network and local area supply projects, such as the Clarington transmission station and Guelph area transmission refurbishment projects; partially offset by
- decreased expenditures on generation customer connection related projects mainly due to the completion of the Barwick and Orleans transmission station projects to replace end-of-life equipment and ensure reliable supply to customers; and
- the completion of transmission station upgrades at the Allanburg transmission station in the Niagara area to enhance system reliability.

Distribution Capital Investments

The following table presents the main components of Hydro One's distribution capital investments during the three months ended June 30, 2015 and 2014:

Three months ended June 30 (millions of Canadian dollars)	**2015**	**2014**	**$ change**	**% change**
Sustainment	123	96	27	28.1
Development	57	60	(3)	(5.0)
Other	12	19	(7)	(36.8)
Total distribution capital investments	192	175	17	9.7

Distribution Sustainment Capital Investments

During the three months ended June 30, 2015, Hydro One's distribution sustainment capital investments were $123 million, compared to $96 million during the same period in 2014, an increase of $27 million or 28.1%. The increase was mainly due to the following:

- increased work within the station refurbishment programs due to the timing of transformer purchases and more refurbishments accomplished during the second quarter of 2015,
- increased focus on capital lines work, mainly due to a higher volume of component replacements and the lines large sustainment initiatives program, which includes line relocations and voltage upgrades,
- the investment in a project to ensure continuity of smart meter and enhance network communications,
- increased volume of joint use and line relocations,
- higher volume of emergency equipment replacements caused by an increased number of trouble calls, and
- higher volume of end-of-life wood pole replacements; partially offset by
- the completion of iTron Sentinel 16S meter replacements in 2014.

Distribution Development Capital Investments

During the three months ended June 30, 2015, Hydro One's distribution development capital investments were $57 million, compared to $60 million during the same period in 2014, a decrease of $3 million, or 5.0%. The decrease is mainly due to the following:

- the completion of the Company's smart meter project in 2014,
- lower volume of distribution generation connection customer-driven work, and
- lower investments related to smart grid initiatives as the next phase is solidified, which will modernize the Company's distribution system to enable remote capability for some functions; partially offset by
- investments in distribution system modifications to improve supply reliability and load capacity.

Distribution Other Capital Investments

During the three months ended June 30, 2015, Hydro One's distribution other capital investments were $12 million, compared to $19 million during the same period in 2014, a decrease of $7 million or 36.8%, due to investments in the Company's payroll, human resources reporting, expense transformation and talent management systems nearing completion.

Six months ended June 30, 2015

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Transmission	445	376	69	18.4
Distribution	324	298	26	8.7
Other	5	2	3	150.0
Total capital investments	774	676	98	14.5

Transmission Capital Investments

The following table presents the main components of Hydro One's transmission capital investments during the six months ended June 30, 2015 and 2014:

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Sustainment	362	290	72	24.8
Development	73	64	9	14.1
Other	10	22	(12)	(54.5)
Total transmission capital investments	445	376	69	18.4

Transmission Sustainment Capital Investments

During the six months ended June 30, 2015, Hydro One's transmission sustainment capital investments were $362 million, compared to $290 million during the same period in 2014, an increase of $72 million or 24.8%. The increase was mainly due to the following:

- several system re-investments, including various end-of-life transformer replacements at the Wiltshire, Dunnville and Timmins transmission stations, the expedited work on 27 circuit breakers replacements at the Richview transmission station to address their deteriorated condition, breaker replacements at the Bruce transmission station to improve reliability and to meet the needs of Bruce Power. In addition, the Company placed in-service the refurbishments work at the Dunnville transmission station in Haldimand County and the transformer replacements at the Dymond transmission station in northeastern Ontario,
- increased volume of station component replacements related to addressing aging equipment as part of the new Station Centric Bundling methodology which addresses a number of capital requirements and enables savings in materials job planning and reduces outage requirements,
- the continued work on overhead lines refurbishment and replacement projects and programs, including investments to address the condition of the conductors on a circuit from the Chats Falls switching station to the Havelock transmission station in southeastern Ontario, as well as increased work on clearance corrections,
- increased volume of transformer purchases for the Company's station demand and spares program,
- increased volume of work related to station security upgrades to prevent unauthorized entry to stations and enhance safety, and increased cyber system replacements to adhere to NERC's Cyber Security standards, and
- a firewall replacement project which will ensure secure access to corporate applications from within the electronic security perimeters at the Company's grid control centre and back-up centre; partially offset by
- decreased expenditures related to underground lines system replacements, as the end-of-life underground transmission cables between the Strachan transformer station and Riverside Junction, which were originally planned for a 2015 in-service date, were replaced and placed in-service in 2014; as well as the completion of refurbishment conductor work on a circuit from the Bannockburn Junction to the Havelock transmission station in the Peterborough area.

Transmission Development Capital Investments

During the six months ended June 30, 2015, Hydro One's transmission development capital investments to expand and reinforce its transmission system were $73 million, compared to $64 million during the same period in 2014, an increase of $9 million or 14.1%. The increase was mainly due to the following:

- increased expenditures related to the timing of work on some of the Company's major local area supply and inter-area network projects, such as the Clarington transmission station and Guelph Area transmission refurbishment projects; partially offset by
- the completion of end-of-life equipment replacements at the Barwick transmission station to meet the needs of transmission customers and ensure reliable supply; and
- the completion of transmission station upgrades at the Allanburg transmission station in the Niagara area to enhance system reliability and allow for the incorporation of new generation in the area, including both transmission and distribution connected renewable generation.

Transmission Other Capital Investments

During the six months ended June 30, 2015, Hydro One's transmission other capital investments were $10 million, compared to $22 million during the same period in 2014, a decrease of $12 million or 54.5%, due to investments in the Company's payroll, human resources reporting, expense transformation and talent management systems nearing completion.

Distribution Capital Investments

The following table presents the main components of Hydro One's distribution capital investments during the six months ended June 30, 2015 and 2014:

Six months ended June 30 (millions of Canadian dollars)	2015	2014	$ change	% change
Sustainment	193	154	39	25.3
Development	101	109	(8)	(7.3)
Other	30	35	(5)	(14.3)
Total distribution capital investments	324	298	26	8.7

Distribution Sustainment Capital Investments

During the six months ended June 30, 2015, Hydro One's distribution sustainment capital investments were $193 million, compared to $154 million during the same period in 2014, an increase of $39 million or 25.3%. The increase was mainly due to the following:

- increased work within the station refurbishment programs due to more refurbishments accomplished and timing of transformer purchases,
- increased focus on capital lines work, primarily related to the large and small sustainment initiatives programs and higher volume of component replacements,
- higher volume of end-of-life wood pole replacements, and
- increased focus on investment in a project to ensure continuity of smart meter and enhance network communications; partially offset by
- the completion of iTron Sentinel 16S meter replacements in 2014.

Distribution Development Capital Investments

During the six months ended June 30, 2015, Hydro One's distribution development capital investments were $101 million, compared to $109 million during the same period in 2014, a decrease of $8 million, or 7.3%. The decrease is mainly due to the following:

- the completion of the Company's smart meter project in 2014,

- lower volume of distribution generation connection customer-driven work, and
- lower expenditures related to smart grid initiatives; partially offset by
- investments in distribution system modifications to improve supply reliability and load capacity.

Distribution Other Capital Investments

During the six months ended June 30, 2015, Hydro One's distribution other capital investments were $30 million, compared to $35 million during the same period in 2014, a decrease of $5 million or 14.3%, due to investments in the Company's payroll, human resources reporting, expense transformation and talent management systems nearing completion.

Major Transmission Projects

The following table summarizes Hydro One's major transmission projects in process during the six months ended June 30, 2015:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date	Status
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	2016	$123 million	$88 million	Project is in progress
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	2016	$103 million	$45 million	Project is in progress
Manby Transmission Station	Toronto Southwestern Ontario	Transmission station upgrade	2016	$24 million	$19 million	Project is in progress
Clarington Transmission Station	Oshawa area Eastern GTA	New transmission station	2018/2019	$297 million	$68 million	Project is in progress
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	To be determined	—	Ontario Energy Board decision for Phase 1 received in July 2015.
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	—	Development work is in progress.

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations, as well as other major commercial commitments:

June 30, 2015 (millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments[1]	9,289	1,016	650	1,628	5,995
Long-term debt – interest payments[1]	7,581	416	758	675	5,732
Pension[2]	272	173	99	—	—
Environmental and asset retirement obligations[3]	275	27	73	66	109
Outsourcing agreements[4]	583	158	264	149	12
Operating lease commitments	46	9	19	11	7
Total contractual obligations	18,046	1,799	1,863	2,529	11,855
Other commercial commitments *(by year of expiry)*					
Bank line[5]	1,500	—	—	1,500	—
Letters of credit[6]	131	131	—	—	—
Guarantees[6]	348	348	—	—	—
Total other commercial commitments	1,979	479	—	1,500	—

(1) The "long-term debt – principal repayments" amounts are not charged to the Company's results of operations, but are reflected on the Company's Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with the long-term debt is recorded in financing charges on the Company's Consolidated Statements of Operations and Comprehensive Income or as a cost of capital programs.

(2) Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2015 and 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013. Minimum pension contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2016 are not estimable at this time.

(3) Hydro One 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 owned by the Company. Hydro One also records a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The forecasted expenditure pattern reflects the company's planned work programs for the periods.

(4) In 2014, Hydro One has finalized a new outsourcing agreement with Inergi LP (Inergi) for the provision of certain services, as well as a facilities outsourcing agreement with Brookfield Johnson Controls Canada LP (Brookfield). The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of the Company's outsourcing agreements are recorded in operation, maintenance and administration costs on the Company's Consolidated Statements of Operations and Comprehensive Income or as a cost of capital programs.

(5) In support of Hydro One's liquidity requirements, the Company had a $1,500 million revolving standby credit facility with a syndicate of banks. On June 1, 2015, the Company extended the maturity date of the revolving standby credit facility from June 2019 to June 2020. No amount was drawn on this facility as at June 30, 2015.

(6) Hydro One currently has outstanding bank letters of credit of $126 million relating to retirement compensation arrangements. These letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. The Company also provides prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At June 30, 2015, Hydro One has provided a letter of credit to the IESO in the amount of $5 million to meet the Company's current prudential requirement. Hydro One has also provided prudential support to the IESO on behalf of its subsidiaries as required by the IESO's Market Rules, using parental guarantees of $347 million, and on behalf of a distributor using total guarantees of $1 million.

Summary of Annual Results

Consolidated Statements of Operations and Comprehensive Income	Year ended December 31		
	2014	2013	2012
	(millions of Canadian dollars, except per share amounts)		
Total revenue	6,548	6,074	5,728
Net income attributable to Shareholder of Hydro One	749	803	745
Earnings per common share *(Canadian dollars)*	7,319	7,850	7,280
Dividends per common share *(Canadian dollars)*	2,696	2,000	3,523
Dividends per preferred share *(Canadian dollars)*	1.375	1.375	1.375

Consolidated Balance Sheets	At December 31		
	2014	2013	2012
	(millions of Canadian dollars)		
Total assets	22,550	21,625	20,811
Total long-term debt	8,925	9,057	8,479
Preferred shares	323	323	323
Net assets	7,947	7,415	6,830

During 2014, the Company earned net income of $749 million and revenues of $6,548 million. The Company made capital investments totalling $1,530 million to improve its transmission and distribution systems' reliability and performance, address its aging power system infrastructure, facilitate new generation, and improve service to its customers.

In August 2014, Hydro One completed the acquisition of Norfolk Power, an electricity distribution and telecom company located in southwestern Ontario. Hydro One has been an electricity distributor in Norfolk County for decades, serving approximately 14,000 Norfolk County customers. The acquisition of Norfolk Power enables the Company to extend its service to the entire Norfolk County and a further 18,000 distribution customers. Hydro One is committed to delivering cost-effective service for Norfolk Power's customers and it remains focused on prudent management, efficient operations and improving the customer experience for everyone it serves. In 2014, the Company also signed agreements to purchase two more local distribution companies: Woodstock Hydro and Haldimand Hydro.

In addition, the Company completed a partnership transaction with the Saugeen Ojibway Nation, where the Saugeen Ojibway Nation acquired a noncontrolling equity interest in a new limited partnership, B2M Limited Partnership.

Performance Measures and Targets

The Company targets and measures its performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that Hydro One maintains a focus on its strategic objectives and take mitigating actions as required. In 2014, the Company met or exceeded eight of 14 performance measure targets. Overall, the Company is making progress towards achieving many of the Company's strategic goals.

Injury-free Workplace

The safety of Hydro One's employees is paramount. For 2014, the Company used the measure of all work-related injuries or illnesses as the performance measure for this strategic objective. A "recordable" injury/illness is one of the following: medical attention (treatment beyond first aid); modified work (restricted duties); lost time; or death. For 2014, the Board of Directors set the target at 1.9 recordable injuries per 200,000 hours worked for this measure. The Company exceeded this target.

Satisfying Hydro One's Customers

In 2014, the Company approached the objective of customer satisfaction by addressing five measures related to improving customer relations. These measures relate to transmission and distribution customer satisfaction, and connection of new services, as well as estimated bills and no bill volume, as part of the Company's customer service recovery project. The Company customer service recovery project was a result of billing issues it encountered due to the implementation in May 2013 of its new customer information system.

- ***Customer Satisfaction – Transmission***

  This measure is to determine the degree to which the Company's transmission customers are satisfied with the service they receive from the Company. It is based on survey results of customer surveys conducted on the Company's behalf by independent third parties. The survey is given to three major groups of transmission customers. In 2014, the Company targeted a transmission customer satisfaction rate of 84%. The Company did not meet this target, achieving 77%.

- ***Customer Satisfaction – Distribution***

  Similar to the transmission customers, the Company surveys its distribution customers to assess the degree to which they are satisfied with the service they receive from the Company. The results arise from surveys conducted on the Company's behalf by independent third parties. This measure reflects the overall satisfaction levels of three major distribution customer segments, based on transaction satisfaction levels, annual satisfaction surveys and the meeting of Ontario Energy Board milestones, respectively, for the three segments. For 2014, the Company set a target for distribution customer satisfaction at 87%, and did well on the transactional elements, but did not meet this target on an overall basis, achieving 85%.

- ***Connection of New Customers***

  This measure relates to distribution low-voltage connections that is reported annually to the Ontario Energy Board. It addresses the Company's customers' needs for a specific and timely connection date and assesses its efficiency in connecting new customers. It measures the percentage of connections for a requested new service (< 750 volts). The connection must be completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and the Company. Hydro One set a 2014 target of 90%, which it exceeded, by achieving 97%.

- ***Unscheduled Estimated Bills***

  With respect to this measure, Hydro One seeks to track its ability to provide accurate bills to customers. The Company tracks the percentage of total customers that have received unscheduled estimates in any billing period. The Company established a target of 1.8% of all bills for this measure. The Company exceeded the target, with only 1.2% of customers receiving unscheduled bills.

- ***No Bill Volume***

  No bill volume is a customer service measure related to the Company's ability to provide timely bills to customers. This measure tracks the number of customers who have not received a bill in three consecutive billing periods. The Company's expectation was to have fewer than 8,000 no-bill customers by September 2014, and sustain this level beyond that date. The Company exceeded this target with only 2,600 no-bill customers.

Continuous Improvement and Cost-effectiveness

As part of the Company's strategic objectives to increase productivity through efficiency improvements and effective management of costs, the Company measures transmission unit cost and distribution unit cost and sets targets for those costs. Regarding the maintenance and reliability of the transmission and distribution systems, the Company continues to build and retain public confidence and trust in the Company's operations. In 2014, the Company continued its focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. The Company is conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

- ***Transmission Unit Costs***

  For 2014, the transmission unit cost measure shows the transmission business cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. The Company set a target of 2.9% for 2014, and exceeded the target, with a 2.7% ratio.

- ***Distribution Unit Costs***

  Similar to transmission unit cost, the distribution unit cost measure demonstrates the distribution cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. For 2014, the Company set a target of 5.7%, but did not meet this target, with a 6.1% ratio.

- ***Customer Interruption Duration – Transmission***

  This measure monitors the reliability of the transmission system by tracking the average length of unplanned interruptions (in minutes) to multiple-circuit supplied delivery points. The Company has set a target of 8.9 minutes per delivery point for 2014. During 2014, the Company was aware that it would miss the target, which was not indicative of degrading reliability, but rather a result of refurbishing aging assets. In doing so, this resulted in occasions where load with a multiple-circuit supply was placed on single supply to accommodate the work program. This exposed the system to interruptions if there was a loss of the single supply. The Company determined that it was important to continue with the maintenance program even if this would result in missing the target. The Company, in fact, did not meet this target, with actual performance at 11.8 minutes per delivery point.

- ***Customer Interruption Duration – Distribution***

  This measure is an indicator of the distribution system reliability that expresses the average length of outages in hours that a customer can expect to experience in the year. This measure excludes force majeure events and loss of supply events (events caused by the transmission system or other distributors). The Company set a target of 6.7 hours per customer for this measure. In 2014, there were numerous storm events which were not considered force majeure events and comparatively more equipment outages that resulted in higher than normal customer interruptions. In the circumstances, the Company did not meet this target, with actual outage duration of 7.4 hours per customer.

Maintaining a Commercial Culture

- ***Net Income***

  Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. The Company's target was $668 million net income after tax for 2014, and the Company exceeded the target, with net income after tax of $749 million.

- ***Customer Service Recovery Cost***

  As a result of billing issues that arose from the implementation of the Company's customer information system in 2013, the effects of which became acute in early 2014, the Company established the customer service recovery project to dedicate staff to resolve outstanding and any new billing issues and stabilize the billing system. The Company anticipated, and fixed as a target, costs of $48 million (including revenue impacts) for this project. The project was completed in 2014 and the customer information system is now in sustainment mode. As the costs of the customer service recovery project exceeded the target, the Company did not meet this anticipated target, with actual costs of $88.3 million.

- ***In-Service Capital – Transmission***

  This new measure for 2014 evaluates how the Company is meeting the Ontario Energy Board targets for in-service capital. For the transmission business, the 2014 target of 85% of in-service capital to the Company's business plan is based on historical performance, its increasing capital work program, and the additional variability caused by external commitments and required approvals. The Company's 2014 result shows that the Company exceeded the target, with 99% of in-service capital.

- ***In-Service Capital – Distribution***

  For the distribution business, the Company set the 2014 target of 87% of in-service capital to the Company's business plan based on historical performance, with adjustments to reflect that its distribution business has more storm-related capital spending than its transmission business, as well as the performance of the Company's smart meter and distributed generation capital work programs. The Company's 2014 result was better than the target, with 97% of in-service capital.

B2M Limited Partnership

In 2012, Hydro One entered into an agreement with the Saugeen Ojibway Nation, where a noncontrolling equity interest in B2M Limited Partnership was made available for purchase at fair value by the Saugeen Ojibway Nation. B2M Limited Partnership was formed by Hydro One in 2013 to hold certain assets relating to the Bruce-to-Milton transmission line and a licence to use the related land. Hydro One maintains and operates the Bruce-to-Milton line. In November 2013, the Ontario Energy Board issued a Decision and Order granting B2M Limited Partnership a transmission licence and granting Hydro One leave to sell the relevant Bruce-to-Milton line transmission assets to B2M Limited Partnership.

On December 16, 2014, the relevant Bruce-to-Milton line transmission assets totalling $526 million were transferred from Hydro One to B2M Limited Partnership. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation acquired a 34.2% equity interest in B2M Limited Partnership for consideration of $72 million, representing the fair value of the equity interest acquired.

Norfolk Power Acquisition

On August 29, 2014, the Company completed the acquisition of the outstanding shares of Norfolk Power from The Corporation of Norfolk County. Norfolk Power is a holding company that owns Norfolk Power Distribution Inc. ("**NPDI**"), a local electricity distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company, located in southwestern Ontario. The selection of Hydro One as successful bidder followed a comprehensive, competitive sales process initiated by Norfolk Power.

The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, was approximately $68 million. The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. Hydro One determined the preliminary purchase price adjustments based on agreed working capital and other balances at the acquisition date. The resulting preliminary goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. The purchase price was finalized during the three months ended March 31, 2015 with no adjustments to the preliminary purchase price allocation as disclosed at December 31, 2014. Norfolk Power contributed revenues of $18 million and net income of less than $1 million for the year ended December 31, 2014.

Woodstock Hydro Acquisition

On May 21, 2014, Hydro One entered into an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro for approximately $29 million, subject to final closing adjustments. Woodstock Hydro is an urban electricity distribution company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and the City of Woodstock which involved consideration of economic development opportunities and other benefits resulting from the sale of Woodstock Hydro. On July 9, 2014, Hydro One filed a Mergers Acquisitions Amalgamations and Divestitures application with the Ontario Energy Board for the approval of the acquisition of Woodstock Hydro. Ontario Energy Board approval of the Woodstock Hydro acquisition was received on September 11, 2015 and closing of the acquisition is anticipated later in 2015.

Outsourcing Agreements

On November 28, 2014, the Company entered into an agreement with Inergi LP ("**Inergi**"), an affiliate of Capgemini Canada Inc., for back office and information technology outsourcing services for a term of 58 months, from March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide Hydro One with payroll, pay operations, information technology and accounting services. Coincident with the conclusion of negotiations on the Inergi agreement, Hydro One reached agreement with Inergi to provide it with call centre operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In September 2014, the Company entered into an agreement with Brookfield Johnson Controls Canada LP ("**Brookfield**") for facilities management services for a term of ten years, from January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. The Brookfield agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by Hydro One, with no minimum capital work guarantee.

See "Liquidity and Capital Resources – Summary of Contractual Obligations and Other Commercial Commitments" in this MD&A.

Results of Operations – Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ change	% change
Revenues	6,548	6,074	474	7.8
Purchased power	3,419	3,020	399	13.2
Operation, maintenance and administration	1,192	1,106	86	7.8
Depreciation and amortization	722	676	46	6.8
	5,333	4,802	531	11.1
Income before financing charges and provision for PILs	**1,215**	**1,272**	**(57)**	**(4.5)**
Financing charges	379	360	19	5.3
Income before provision for PILs	**836**	**912**	**(76)**	**(8.3)**
Provision for PILs	89	109	(20)	(18.3)
Net income	**747**	**803**	**(56)**	**(7.0)**
Net income (loss) attributable to noncontrolling interest	(2)	—	(2)	(100.0)
Net income attributable to Shareholder of Hydro One	**749**	**803**	**(54)**	**(6.7)**

Net Income

The Company's 2014 net income attributable to the Shareholder of Hydro One decreased by $54 million, or 6.7%, to $749 million, compared to 2013. The decrease is primarily due to the following:

- $70 million increase in the Company's 2014 distribution operation, maintenance and administration costs, mainly due to its customer service recovery initiatives and the increase in its bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014, and
- $46 million increase in the Company's 2014 depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense in 2014, related to the growth in capital assets as it continues to place new assets in-service, consistent with its ongoing capital work program; partially offset by
- $59 million increase in its 2014 transmission revenues, mainly due to new Ontario Energy Board-approved 2014 transmission rates.

Revenues

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ change	% change
Transmission	1,588	1,529	59	3.9
Distribution	4,903	4,484	419	9.3
Other	57	61	(4)	(6.6)
	6,548	6,074	474	7.8
Average annual Ontario 60-minute peak demand (MW)[(1)]	20,596	21,493	(897)	(4.2)
Distribution – units distributed to Hydro One customers (TWh)[(1)]	29.8	29.8	—	—

(1) System-related statistics are preliminary.

Transmission

The Company's 2014 transmission revenues increased by $59 million, or 3.9%, compared to 2013. The components of the increase include the following:

- $90 million increase due to new transmission rates effective January 1, 2014 approved by the Ontario Energy Board in January 2014, and
- $42 million increase due to the Ontario Energy Board's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain Ontario Energy Board-approved transmission regulatory accounts; partially offset by
- $45 million decrease due to lower average Ontario 60-minute peak demand in 2014. The lower electricity demand in 2014 was mainly due to milder weather in the summer and fall of 2014, compared to 2013, and
- $28 million decrease due to ancillary transmission revenues, primarily associated with Ontario Energy Board-approved regulatory accounts.

Distribution

The Company's 2014 distribution revenues increased by $419 million, or 9.3%, compared to 2013. The components of the increase include the following:

- $399 million increase due to the recovery of higher purchased power costs, as described below under "Purchased Power Costs",
- $12 million increase due to new distribution rates effective January 1, 2014 approved by the Ontario Energy Board in December 2013, and
- $8 million increase due to ancillary distribution revenues, primarily associated with Ontario Energy Board-approved regulatory accounts.

Purchased Power Costs

The Company's purchased power costs increased by $399 million, or 13.2%, in 2014, compared to 2013. The components of the increase include the following:

- $291 million increase resulting from higher purchased power costs for customers who are not eligible for the Regulated Price Plan,
- $78 million increase resulting from the impact of changes in the Ontario Energy Board's Regulated Price Plan rates for residential and other eligible customers,
- $26 million increase resulting from the Ontario Energy Board transmission rate decision effective January 1, 2014,

- $10 million increase due to wholesale market service charges levied by the IESO, and
- $4 million increase resulting from the IESO's smart metering entity charge effective May 1, 2013; partially offset by
- $10 million decrease due to lower energy consumption in 2014, mainly resulting from a milder summer and a warmer fall in 2014.

Operation, Maintenance and Administration Costs

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ change	% change
Transmission	394	375	19	5.1
Distribution	742	672	70	10.4
Other	56	59	(3)	(5.1)
	1,192	1,106	86	7.8

Transmission

The Company's 2014 transmission operation, maintenance and administration costs increased by $19 million, or 5.1%, compared to 2013. The components that contributed to the increase include the following:

- increased forestry expenditures related to brush control and line clearing on the Company's transmission rights-of-way,
- higher volume of corrective and preventive maintenance on power equipment and overhead lines, and transmission site facilities maintenance requirements, and
- one-time reduction to Hydro One's provision for payments in lieu of property taxes in 2013 related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of its property tax returns; partially offset by
- lower expenditures due to the recovery of insurance proceeds for the 2013 floods at Hydro One's Richview and Manby transmission stations, and
- increased attribution of overheads to capital project expenditures in 2014.

Distribution

The Company's 2014 distribution operation, maintenance and administration costs increased by $70 million, or 10.4%, compared to 2013. The increase is mainly due to the following:

- the Company's customer service recovery initiatives and the increase in its bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014. The Company resumed some of its collection tools and efforts in September 2014. Hydro One Networks Inc.'s customer service recovery initiatives and related bad debt expense totalled $88 million in 2014.

The increase was partially offset by decreased expenditures in 2014 related to the CIS, as it was placed in-service in May 2013.

Depreciation and Amortization

The Company's 2014 depreciation and amortization costs increased by $46 million, or 6.8%, compared to 2013. This increase was primarily attributable to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as Hydro One continues to place new assets in-service, consistent with its ongoing capital work program.

Financing Charges

The Company's 2014 financing charges increased by $19 million, or 5.3%, compared to 2013. The increase is primarily due to the following:

- increase in interest expense on its long-term debt due to a higher average level of debt; partially offset by
- lower average interest rate.

Provision for PILs

The provision for PILs decreased by $20 million, or 18.3%, to $89 million in 2014, compared to 2013, primarily due to lower levels of pre-tax income in 2014 compared to 2013.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2013 through to December 31, 2014. This information has been derived from the Company's unaudited interim consolidated financial statements and its audited annual consolidated financial statements.

	2014				2013			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**
	(millions of Canadian dollars)							
Total revenue	1,662	1,556	1,566	1,764	1,557	1,542	1,403	1,572
Net income attributable to Shareholder of Hydro One	221	173	115	240	160	218	168	257
Net income to common Shareholder of Hydro One	216	169	110	236	155	214	163	253

Electricity demand generally follows normal weather-related variations, and consequently, the Company's electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

Results of Operations – Three Months Ended December 31, 2014 Compared to Three Months Ended December 31, 2013

Three months ended December 31 (millions of Canadian dollars)	2014	2013	$ change	% change
Revenues	1,662	1,557	105	6.7
Purchased power	893	794	99	12.5
Operation, maintenance and administration	247	286	(39)	(13.6)
Depreciation and amortization	190	184	6	3.3
	1,330	1,264	66	5.2
Income before financing charges and provision for PILs	**332**	**293**	**39**	**13.3**
Financing charges	98	93	5	5.4
Income before provision for PILs	234	**200**	34	17.0
Provision for PILs	15	40	(25)	(62.5)
Net income	**219**	**160**	**59**	**36.9**
Net income (loss) attributable to noncontrolling interest	(2)	—	(2)	(100.0)
Net income attributable to Shareholder of Hydro One	**221**	**160**	**61**	**38.1**

Net Income

Net income attributable to the Shareholder of Hydro One for the three months ended December 31, 2014 was $221 million, compared to $160 million during the same period in 2013, an increase of $61 million or 38.1%. The increase is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013, and decreased expenditures related to brush control and distribution line maintenance work,

- decrease in the Company's provision for PILs, primarily due to changes in net temporary differences, and
- increase in the Company's 2014 transmission revenues, mainly due to new Ontario Energy Board-approved 2014 transmission rates.

Revenues

Hydro One's total revenues for the three months ended December 31, 2014 were $1,662 million, compared to $1,557 million during the same period in 2013, an increase of $105 million or 6.7%. The increase is mainly due to the following:

- the recovery of higher purchased power costs,
- new transmission and distribution rates effective January 1, 2014, and
- the Ontario Energy Board's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain Ontario Energy Board-approved transmission regulatory accounts; partially offset by
- lower average Ontario 60-minute peak demand and energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014, and
- lower ancillary revenues, primarily associated with Ontario Energy Board-approved regulatory accounts.

Purchased Power Costs

The Company's purchased power costs for the three months ended December 31, 2014 were $893 million, compared to $794 million during the same period in 2013, an increase of $99 million or 12.5%. The increase is mainly due to the following:

- higher purchased power costs for customers who are not eligible for the Regulated Price Plan; and
- partially offset by lower energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014,
- wholesale market service charges levied by the IESO, and
- Ontario Energy Board transmission rate decision effective January 1, 2014.

Operation, Maintenance and Administration

The Company's operation, maintenance and administration costs for the three months ended December 31, 2014 were $247 million, compared to $286 million during the same period in 2013, a decrease of $39 million or 13.6%. The decrease is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013, and
- decreased expenditures related to brush control and distribution line maintenance work.

Depreciation and Amortization

The Company's depreciation and amortization costs for the three months ended December 31, 2014 were $190 million, compared to $184 million during the same period in 2013, an increase of $6 million or 3.3%. The increase is mainly due to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as the Company continue to place new assets in-service, consistent with its ongoing capital work program.

Financing Charges

The Company's financing charges for the three months ended December 31, 2014 were $98 million, compared to $93 million during the same period in 2013, an increase of $5 million or 5.4%. The increase is mainly due to the following:

- increase in interest expense on its long-term debt due to a higher average level of debt; partially offset by
- lower average interest rates.

Provision for PILs

Hydro One's provision for PILs for the three months ended December 31, 2014 was $15 million, compared to $40 million during the same period in 2013, a decrease of $25 million or 62.5%. The decrease is due to the following:

- changes in net temporary differences, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed for accounting purposes, and interest deducted for tax purposes in excess of interest expensed for accounting purposes; partially offset by
- higher pre-tax income for the three months ended December 31, 2014 compared to the same period in 2013.

Results of Operations – Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Year ended December 31 (millions of Canadian dollars)	2013	2012	$ change	% change
Revenues	6,074	5,728	346	6.0
Purchased power	3,020	2,774	246	8.9
Operation, maintenance and administration	1,106	1,071	35	3.3
Depreciation and amortization	676	659	17	2.6
	4,802	4,504	298	6.6
Income before financing charges and provision for PILs	**1,272**	**1,224**	**48**	**3.9**
Financing charges	360	358	2	0.6
Income before provision for PILs	**912**	**866**	**46**	**5.3**
Provision for PILs	109	121	(12)	(9.9)
Net income	803	**745**	**58**	**7.8**
Net income (loss) attributable to noncontrolling interest	—	—	—	—
Net income attributable to Shareholder of Hydro One	**803**	**745**	**58**	**7.8**

Net Income

The Company's 2013 net income increased by $58 million, or 7.8%, to $803 million, compared to 2012. The Company experienced higher distribution revenues in 2013 mainly reflecting increased purchased power costs, primarily related to the Ontario Energy Board's Regulated Price Plan rate-setting process and the IESO's spot market. It also experienced increased transmission revenues in 2013 reflecting a higher peak demand due to intermittent periods of hot weather in the summer of 2013, as well as extreme cold winter weather. The Company's 2013 net income was also positively impacted by a lower provision for PILs and by a reduction to its provision for payments in lieu of transmission station property taxes, following the finalization of the assessment of certain prior years' property tax returns. This reduction was partially offset by power restoration expenditures following several major storms in 2013.

Revenues

Year ended December 31 (millions of Canadian dollars)	2013	2012	$ change	% change
Transmission	1,529	1,482	47	3.2
Distribution	4,484	4,184	300	7.2
Other	61	62	(1)	(1.6)
	6,074	5,728	346	6.0
Average annual Ontario 60-minute peak demand (MW)(1)	21,493	21,132	361	1.7
Distribution – units distributed to Hydro One customers (TWh)(1)	29.8	29.2	0.6	2.1

(1) System-related statistics are preliminary.

Transmission

Hydro One's 2013 transmission revenues were higher by $47 million, or 3.2%, compared to 2012. The average Ontario 60-minute peak demand was higher in 2013 compared to 2012, resulting in an increase in transmission revenues of $26 million, compared to 2012. The higher energy consumption in 2013 mainly resulted from a warmer summer and a colder winter, as compared to 2012. In addition, the Company experienced higher revenues of $21 million in 2013, associated with the Ontario Energy Board's approval of export service revenues and ancillary services.

Distribution

The Company's 2013 distribution revenues were higher by $300 million, or 7.2%, compared to 2012. The increase was primarily due to the recovery of higher purchased power costs of $246 million, as described below under "Purchased Power Costs." In addition, energy consumption was higher by $29 million in 2013, mainly resulting from a warmer summer and a colder winter, as compared to 2012. Distribution revenues also increased by $15 million as a result of the Company's placement in service of new smart grid and smart meter investments, which are currently being recovered through separate rate mechanisms.

In December 2012, the Ontario Energy Board approved new distribution rates effective January 1, 2013, based on its third generation incentive regulation mechanism process. As part of this decision, the Ontario Energy Board approved the Company's application for an additional rate rider related to an incremental capital module adjustment to its rates, reflecting its placement in service of certain specific capital investments. This approval resulted in an increase in distribution revenues of $13 million, compared to 2012. In addition, the Ontario Energy Board's incentive regulation mechanism decision resulted in higher distribution revenues of $10 million, which will support the maintenance and investment requirements of the Company's distribution system and enable the safe and reliable delivery of electricity to its customers throughout Ontario. The 2013 distribution revenue increases were partially offset by lower 2013 ancillary distribution revenues of $13 million, primarily associated with Ontario Energy Board-approved regulatory accounts.

Purchased Power Costs

The Company's 2013 purchased power costs increased by $246 million, or 8.9%, to $3,020 million, compared to 2012. The components of increase include the following:

- $104 million increase resulting from higher purchased power costs for customers who are not eligible for the Regulated Price Plan,
- $85 million increase resulting from the impact of changes in the Ontario Energy Board's Regulated Price Plan rates for residential and other eligible customers,
- $44 million increase due to higher electricity demand, and
- $9 million increase resulting from the IESO's smart metering entity charge effective May 1, 2013; partially offset by
- $4 million reduction in wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration

Year ended December 31 (millions of Canadian dollars)	2013	2012	$ change	% change
Transmission	375	402	(27)	(6.7)
Distribution	672	608	64	10.5
Other	59	61	(2)	(3.3)
	1,106	1,071	35	3.3

Transmission

The Company's 2013 transmission operation, maintenance and administration costs decreased by $27 million, or 6.7%, to $375 million, compared to 2012. Within the Company's work programs, it continued to invest in the safe and reliable operation of its transmission system.

Expenditures in support of the Company's transmission system decreased by $33 million in 2013, compared to 2012, primarily due to a reduction to its provision for payments in lieu of property taxes related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of its property tax returns. The decrease in the Company's transmission system support costs was partially offset by an increase of $6 million in its work program costs, compared to 2012. This increase was primarily due to higher expenditures related to the Company's forestry work program on its transmission rights-of-way resulting from heavy tree densities, power equipment preventive and corrective maintenance, and emergency restoration requirements as a result of severe flooding at Richview and Manby transmission stations caused by a major rainstorm in July 2013. The Company also experienced increased cyber security and internal compliance program requirements related to the reliability standards and criteria mandated by the NERC. These increases in work program costs were partially offset by lower expenditures related to the Ontario Power Authority's (IESO effective January 1, 2015) recommendation to increase short circuit and/or transformer capacity at ten of the Company's transmission stations to enable the connection of small renewable projects, as this work was substantially completed by the end of 2012. Expenditures for these station upgrades were recorded within operation, maintenance and administration rather than as capital expenditures, given that recovery was restricted pursuant to a shareholder declaration made in April 2011. No such declarations were issued in 2013. In addition, the Company experienced lower expenditures within its overhead lines program

Distribution

The Company's 2013 distribution operation, maintenance and administration costs increased by $64 million, or 10.5%, to $672 million, compared to 2012. The Company's work program expenditures increased by $63 million compared to 2012, mainly as a result of increased power restoration expenditures following major storms in 2013, increased customer-driven work related to trouble calls and cable locates in support of the Company's "One Call" program, higher requirements within the line patrol program, higher expenditures on its customer care programs, higher information technology improvements and enhancements, and continued work on the Company's smart grid project. These impacts were partially offset by lower station corrective and preventive maintenance expenditures, as well as lower line clearing expenditures, compared to 2012. The Company's expenditures in support of its distribution system increased marginally by $1 million, compared to 2012.

Depreciation and Amortization

The Company's 2013 depreciation and amortization costs increased by $17 million, or 2.6%, compared to 2012. This increase was attributable to higher 2013 depreciation expense, primarily related to its placement of new assets in service consistent with its ongoing capital work program, as well as higher asset removal costs in 2013.

Financing Charges

Financing charges increased by $2 million, or 0.6%, to $360 million for 2013, compared to 2012. Higher financing costs in 2013 were mainly due to a decrease in interest capitalized, partially offset by a decrease in interest expense on long-term debt due to lower average interest rates.

Provision for PILs

The provision for PILs decreased by $12 million, or 9.9%, to $109 million in 2013, compared to 2012. This decrease primarily resulted from changes in net temporary differences, and a true-up relating to the 2012 research and development tax credits. This reduction was partially offset by the impact of higher levels of pre-tax income in 2013, compared to 2012.

Liquidity and Capital Resources for Annual Periods

Hydro One's primary sources of liquidity and capital resources are funds generated from the Company's operations, debt capital market borrowings and bank financing. These resources will be used to satisfy its capital resource requirements, which continue to include its capital expenditures, servicing and repayment of its debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Operating activities	1,256	1,404	1,294
Financing activities			
Long-term debt issued	628	1,185	1,085
Long-term debt retired	(776)	(600)	(600)
Amount contributed by noncontrolling interest	72	—	—
Dividends paid	(287)	(218)	(370)
Investing activities			
Capital expenditures	(1,504)	(1,387)	(1,463)
Acquisition of Norfolk Power	(66)	—	—
Proceeds from investment	250	—	—
Other financing and investing activities	(38)	(14)	21
Net change in cash and cash equivalents	(465)	370	(33)

Cash from Operating Activities

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Net cash from operating activities decreased by $148 million to $1,256 million in 2014, compared to 2013. The decrease was primarily due to the following:

- lower 2014 net income, compared to 2013,
- changes in accrual balances, mainly related to timing of capital projects, and
- changes in regulatory accounts, including the retail settlement and external revenue variance accounts; partially offset by
- higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as the Company continues to place new assets in-service, consistent with the Company's ongoing capital work program.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Net cash from operating activities increased by $110 million to $1,404 million in 2013, compared to 2012. The increase was primarily due to higher 2013 net income, compared to 2012, as well as changes in accrual balances, mainly related to timing of tax payments and to capital projects. The increase was partially offset by growth in accounts receivable balances, resulting from higher revenues and lower collections in the period.

Financing Activities

Short-term liquidity is provided through funds from operations, the Company's commercial paper program, and the Company's revolving credit facility.

At December 31, 2014, under the commercial paper program, Hydro One was authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $1.5 billion committed revolving credit facility with a syndicate of banks. The short-term liquidity under this program and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2014, the Company had $8,923 million in long-term debt outstanding, including the current portion. The Company's notes and debentures mature between 2015 and 2064. Long-term financing is provided by the Company's access to the debt markets, primarily through its MTN Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available until October 2015. The Company plans to file a base shelf prospectus to renew its MTN Program for another 25 months by the end of 2015.

At December 31, 2013, the Company had $9,045 million in long-term debt outstanding, including the current portion. At December 31, 2013, $1,815 million of $3 billion maximum authorized principal amount of medium-term notes under the MTN Program remained available until October 2015.

In 2014, the Company issued $628 million of long-term debt under the Company's MTN Program, compared to $1,185 million of long-term debt issued in 2013. In 2014, the Company also repaid $750 million in maturing long-term debt, compared to $600 million of long-term debt repaid in 2013. In addition, long-term debt totalling $26 million assumed on the Norfolk Power acquisition was repaid in September 2014.

In 2013, Hydro One issued $1,185 million of long-term debt under the Company's MTN Program, compared to $1,085 million of long-term debt issued in 2012. In 2013, the Company also repaid $600 million in maturing long-term debt, compared to $600 million of long-term debt called and redeemed in 2012, prior to its maturity date of November 15, 2012.

The Company had no short-term notes outstanding at December 31, 2014, 2013, or 2012.

During 2014, Hydro One paid dividends to the Province in the amount of $287 million, consisting of $269 million in common share dividends and $18 million in preferred share dividends, compared to dividends of $218 million, consisting of $200 million of common share dividends and $18 million of preferred share dividends, paid to the Province in 2013, and dividends of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends paid to the province in 2012. In 2013, cash dividends per common share were $2,000, compared to $3,523 per common share in 2012. Cash dividends per preferred share were $1.375 in each of 2013 and 2012.

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to its Shareholder.

Investing Activities

During 2014, the Company continued to focus on making important investments in its transmission and distribution systems to address its aging power system infrastructure, improve its systems' reliability and performance, and improve service to its customers. Hydro One made capital investments totalling $1,530 million in 2014, compared to $1,394 million of capital investments in 2013, and have placed $1,574 million of new assets in-service in 2014, compared to $1,491 million of new assets placed in-service in 2013.

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to sustaining, enhancing and reinforcing the Company's transmission and distribution infrastructure.

	Year ended December 31		
	2014	**2013**	**2012**
	(millions of Canadian dollars)		
Transmission	845	714	776
Distribution	680	673	671
Other	5	7	7
Total capital investments	1,530	1,394	1,454

Transmission Capital Investments

The Company's 2014 transmission capital investments were $845 million, compared to $714 million in 2013, an increase of $131 million or 18.3%, primarily due to sustainment programs to address its aging infrastructure. Given the aging of its infrastructure, the Company has ongoing investment plans which are designed to reliably power the Ontario economy and to support the innovation that can be expected over the next decade.

The Company's 2013 transmission capital investments decreased by $62 million, or 8.0%, to $714 million, compared to 2012.

	Year ended December 31		
	2014	2013	2012
	(millions of Canadian dollars)		
Sustainment	625	481	392
Development	132	170	313
Other	88	63	71
Total transmission capital investments	845	714	776

Transmission Sustainment Capital Investments

The Company's current transmission sustainment programs include protection and control systems, wood poles, breakers and high-voltage instrument transformer replacements. The Company's 2014 transmission sustainment capital investments were $625 million, compared to $481 million in 2013, an increase of $144 million or 29.9%. The increase was mainly due to the following:

- several system re-investments, including the Gerrard and Timmins transmission stations and new type of breakers at its Bruce transmission station, which progressed in 2014, as well as completed projects, such as the Pinard transmission station breakers and the Wallaceburg transmission station;
- several replacements of end-of-life power transformers at its Pembroke transmission Station in eastern Ontario, and its Hanover, Allanburg, and Elmira transmission stations in southwestern Ontario, as well as the emergency replacement of a unit at the Trafalgar transmission station;
- increased work within its station and lines equipment replacement and refurbishment projects and programs, including its investment to address the condition of the conductors on the 170 kilometre circuit from the Chats Falls switching station to the Havelock transmission station in southeastern Ontario, and increased work on overhead lines wood pole structure replacements; and
- increased volume of replacements related to addressing aging protection and control equipment.

Investments to sustain the Company's existing transmission system were $481 million in 2013, representing an increase of $89 million or 22.7%, compared to 2012. In 2013, Hydro One made significant investments in the refurbishment and replacement of end-of-life equipment for overhead lines and system re-investments in order to improve reliability, as well as replacement of circuit breakers. In addition, the Company has experienced higher expenditures associated with the timing of work related to the replacement of end-of-life power transformers. Hydro One continued work on replacing end-of-life underground transmission cables between its Strachan transmission station and Riverside Junction. These new underground cables will maintain a reliable supply of electricity to downtown Toronto. These increases were partially offset by lower expenditures related to the replacement of protection and control equipment.

Transmission Development Capital Investments

The Company's current transmission development projects include transmission system upgrades, local area supply projects, and inter-area network projects. These investments will expand and reinforce power reliability for electricity customers throughout the province, including its residential and industrial customers. The Company's 2014 development capital investments to expand and reinforce its transmission system were $132 million, compared to $170 million in 2013, a decrease of $38 million or 22.4%. The decrease was mainly due to the following:

- the successful completion of Sundusk and Summerhaven switching stations upgrades in 2013 to incorporate renewable energy into its transmission system; and
- reduced expenditures related to some of its major projects which were completed in 2014, such as the Lambton-to-Longwood transmission upgrade project, the Barwick transmission station, and the Allanburg transmission station to ensure mandatory transmission system standards were met.

Investments to expand and reinforce the Company's transmission system were $170 million in 2013, representing a decrease of $143 million, compared to 2012. The decrease was mainly due to the completion of the Company's Bruce-to-Milton transmission line to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. This project was placed in-service in May 2012. In addition, the Company experienced lower expenditures as a result of completing its Commerce Way transmission station, a new load supply station in the City of Woodstock to address load growth issues in the Woodstock area, and the switchyard reconstruction project at its Burlington transmission station, where two new switchyards were constructed to increase the load supply capacity and to ensure reliability of supply to customers in the area. These projects were placed in-service in February 2013 and December 2012, respectively.

During 2013, the Company continued to invest in inter-area network projects to support the Province's supply mix objectives for generation, and in load customer connections and local area supply projects to address growing loads. The Company's local area supply project expenditures included investments in its Midtown transmission reinforcement project, which will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work at the Company's Hearn switching station was partially completed in December 2013, where the Company rebuilt an existing switchyard that had reached the end of its service life. The Company was also constructing its Lambton-to-Longwood transmission upgrade to increase transmission capability between its Lambton (Sarnia) and Longwood (London) transmission stations.

Transmission Other Capital Investments

The Company's 2014 other transmission capital investments were $88 million, compared to $63 million in 2013, an increase of $25 million or 39.7%. The increase was mainly due to the following:

- the development phase investment in its network management system project, a critical operating tool used for monitoring and control of its transmission system, and
- the investment in its payroll transformation project to realize various process efficiencies; partially offset by
- higher investments in 2013 as a result of emergency flood restoration work at its Richview transmission station resulting from a major rainstorm in July 2013.

The Company's other transmission capital investments were $63 million in 2013, representing a decrease of $8 million, compared to 2012. The decrease was mainly due to lower requirements associated with information technology initiatives, including its entity-wide enterprise information system replacement and improvement project, and timing of field facilities improvements. These reductions were partially offset by increased fleet acquisitions and emergency flood restoration work at its Richview transmission station caused by a major rainstorm in July 2013.

Distribution Capital Investments

The Company's 2014 distribution capital investments were $680 million, compared to $673 million in 2013, an increase of $7 million or 1.0%, primarily due to its distribution sustainment programs to address its aging infrastructure.

The Company's 2013 distribution capital investments increased by $2 million, or 0.3%, to $673 million, compared to 2012.

	Year ended December 31		
	2014	**2013**	**2012**
	(millions of Canadian dollars)		
Sustainment	356	324	245
Development	236	235	284
Other	88	114	142
Total distribution capital investments	680	673	671

Distribution Sustainment Capital Investments

The Company's current distribution sustainment programs include wood pole and meter replacements, emergency work for storm restoration, distribution station refurbishments and upgrades, and work related to joint-use and relocation of its distribution lines. The Company's 2014 distribution sustainment capital investments were $356 million, compared to $324 million in 2013, an increase of $32 million or 9.9%. The increase is mainly due to the following:

- increased investments in meter replacements, including certain meter replacements and field metering services installations,
- higher volume of end-of-life wood pole replacements,
- increased focus on capital lines work, mainly due to the lines large sustainment initiatives program, and
- increased work within its station refurbishment programs due to more refurbishments accomplished in 2014; partially offset by
- reduced storm restoration work in 2014 due to lower storm activity compared to 2013.

Investments to sustain the Company's distribution system were $324 million in 2013, representing an increase of $79 million or 32.2%, compared to 2012. The increase was primarily due to increased expenditures for replacements related to storm restoration work caused by major storms in 2013. The Company also experienced increased work within its wood pole replacement program and station refurbishment projects. Investments were also impacted by the timing of customer contribution payments received in 2012 relating to work for joint use and relocation of its lines. These increases were partially offset by lower work within the Company's lines programs.

Distribution Development Capital Investments

The Company's current development projects to expand and reinforce its distribution network include new customer connections and upgrades, system capability reinforcement projects, line transfers requested by customers, and connections to new generation facilities. The Company's 2014 distribution development capital expenditures were $236 million, compared to $235 million in 2013, an increase of $1 million or 0.4%. The increase is mainly due to the following:

- increased work for subdivision connections, new customer connections, and upgrades, and
- the purchase of retail revenue meters for all new connections and service upgrades; partially offset by
- reduced lines and stations work related to upgrading and adding capacity to the Company's distribution system.

Investments to expand and reinforce its distribution network were $235 million in 2013, representing a decrease of $49 million, compared to 2012. Hydro One experienced reduced expenditures related to some of its major projects, including its smart grid project, as it completed the deployment of its distribution management system within the Owen Sound pilot area in 2012, and the smart metering project, as most of the network expansion work was completed in 2012. In 2013, the Company also experienced a lower demand for new customer connections and upgrades. These decreases were partially offset by increased work on upgrading and adding capacity to its system to enable new customer connections and timing of generation connection projects.

Distribution Other Capital Investments

The Company's 2014 other distribution capital expenditures were $88 million, compared to $114 million in 2013, a decrease of $26 million or 22.8%. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to the CIS, as it was placed in-service in May 2013,
- decrease due to higher investments in 2013 as a result of emergency flood restoration work at its Richview transmission station resulting from a major rainstorm in July 2013; partially offset by
- investment in a payroll transformation project to realize various process efficiencies.

The Company's other distribution capital investments were $114 million in 2013, representing a decrease of $28 million or 19.7%, compared to 2012. The majority of these expenditures were related to the CIS phase of its entity-wide information system replacement and improvement project, which was placed into service in May 2013. In addition to replacing end-of-life systems, this implementation is expected to result in process improvements that are expected to provide many benefits including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information. Productivity savings are also anticipated to result from performance improvements, consolidation and/or decommissioning of legacy information technology systems. In addition, the Company experienced decreased expenditures associated with information technology initiatives, including its entity-wide enterprise information system replacement and improvement project, and the timing of field facilities improvements, partially offset by an increase in fleet acquisitions and emergency flood restoration work at its Richview transmission station.

Related Party Transactions

Hydro One is currently owned by the Province. The Ontario Electricity Financial Corporation, IESO, Ontario Power Authority (merged with IESO effective January 1, 2015), Ontario Power Generation Inc., and the Ontario Energy Board are related parties to the Company because they are controlled or significantly influenced by the Province.

Three and six months ended June 30, 2015 compared to June 30, 2014

The Province

- During the three and six months ended June 30, 2015, Hydro One paid dividends to the Province totalling $30 million and $59 million, respectively, compared to $30 million and $229 million paid in the same periods in 2014.

IESO

- During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $471 million and $1,262 million, respectively, from the IESO-administered electricity market, compared to $568 million and $1,343 million purchased in the same periods in 2014.
- Hydro One receives revenues for transmission services from the IESO, based on Ontario Energy Board-approved transmission rates. The Company's transmission revenues for the three and six months ended June 30, 2015 include $363 million and $768 million, respectively, related to these services, compared to $368 million and $776 million in the same periods in 2014.
- Hydro One receives amounts for rural rate protection from the IESO. The Company's distribution revenues for the three and six months ended June 30, 2015 include $32 million and $64 million, respectively, related to this program, compared to $32 million and $64 million in the same periods in 2014.
- Hydro One receives revenues related to the supply of electricity to remote northern communities from the IESO. The Company's distribution revenues for the three and six months ended June 30, 2015 include $8 million and $16 million, respectively, related to these services, compared to $8 million and $16 million in the same periods in 2014.
- The IESO (Ontario Power Authority prior to January 1, 2015) funds substantially all of Hydro One's Conservation and Demand Management ("**CDM**") programs. The funding includes program costs, incentives, and management fees. During the three and six months ended June 30, 2015, the Company received $11 million and $23 million, respectively, from the IESO related to these programs, compared to $14 million and $21 million received in the same periods in 2014.

Ontario Power Generation Inc.

- During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $2 million and $8 million, respectively, from Ontario Power Generation Inc., compared to $4 million and $18 million purchased in the same periods in 2014.

- Hydro One has service level agreements with Ontario Power Generation Inc. These services include field, engineering, logistics and telecommunications services. The Company's other revenues for the three and six months ended June 30, 2015 include $1 million and $3 million, respectively, related to these service level agreements, compared to $3 million and $6 million in the same periods in 2014. Operation, maintenance and administration costs related to the purchase of services with respect to these service level contracts were insignificant during the three months ended June 30, 2015 and 2014, and $1 million during the six months ended June 30, 2015 and 2014.

Ontario Electricity Financial Corporation

- During the three and six months ended June 30, 2015, Hydro One paid PILs to the Ontario Electricity Financial Corporation totalling $14 million and $32 million, respectively, compared to payments of $21 million and $43 million made in the same periods in 2014.
- During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $2 million and $4 million, respectively, from power contracts administered by the Ontario Electricity Financial Corporation, compared to $2 million and $7 million purchased in the same periods in 2014.
- During the six months ended June 30, 2015, the Company paid a $5 million annual fee to the Ontario Electricity Financial Corporation, compared to $5 million paid in the same period in 2014, for indemnification against adverse claims in excess of $10 million paid by the Ontario Electricity Financial Corporation with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

Ontario Energy Board

- Under the Ontario Energy Board Act, the Ontario Energy Board is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. During the three and six months ended June 30, 2015, Hydro One incurred $3 million and $6 million, respectively, in Ontario Energy Board fees, compared to $3 million and $6 million incurred in the same periods in 2014.

At June 30, 2015, the amounts due from and due to related parties as a result of the transactions described above were $177 million and $52 million, respectively, compared to $224 million and $227 million at December 31, 2014, respectively. At June 30, 2015, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $41 million, compared to $214 million at December 31, 2014.

Year ended December 31, 2014 compared to year ended December 31, 2013

The Province

- During 2014, Hydro One paid dividends to the Province totalling $287 million, compared to $218 million paid in 2013.
- In November 2014, Hydro One redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

- During 2014, Hydro One purchased power in the amount of $2,601 million from the IESO-administered electricity market, compared to $2,477 million purchased in 2013.
- The Company's 2014 transmission revenues include $1,556 million related to transmission services, compared to $1,509 million in 2013.
- The Company's 2014 distribution revenues include $127 million related to the rural rate protection program, compared to $127 million in 2013.
- The Company's 2014 distribution revenues include $32 million related to the supply of electricity to remote northern communities, compared to $33 million in 2013.

Ontario Power Authority (merged with IESO effective January 1, 2015)

- During 2014, Hydro One received $33 million related to CDM programs, compared to $34 million received in 2013.

Ontario Power Generation Inc.

- During 2014, Hydro One purchased power in the amount of $23 million from Ontario Power Generation Inc., compared to $15 million in 2013.
- Hydro One's 2014 other revenues include $12 million related to service level agreements with Ontario Power Generation Inc., compared to $9 million in 2013. Hydro One's 2014 operation, maintenance and administration costs related to the purchase of services with respect to these service level contracts were $1 million, compared to $1 million in 2013.

Ontario Electricity Financial Corporation

- During 2014, Hydro One paid PILs to the Ontario Electricity Financial Corporation totalling $86 million, compared to payments of $138 million made in 2013.
- During 2014, Hydro One purchased power in the amount of $9 million from power contracts administered by the Ontario Electricity Financial Corporation, compared to $8 million purchased in 2013.
- During 2014, the Company paid a $5 million annual fee to the Ontario Electricity Financial Corporation, compared to $5 million paid in 2013, for indemnification against adverse claims in excess of $10 million paid by the Ontario Electricity Financial Corporation with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

Ontario Energy Board

- During 2014, Hydro One incurred $12 million in Ontario Energy Board fees, compared to $12 million incurred in 2013.

At December 31, 2014, the amounts due from and due to related parties as a result of the transactions described above were $224 million and $227 million, respectively, compared to $197 million and $230 million at December 31, 2013, respectively. At December 31, 2014, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $214 million, compared to $217 million at December 31, 2013.

Year ended December 31, 2013 compared to year ended December 31, 2012

Transmission revenues include $1,509 million (2012 – $1,474 million) received from IESO related to transmission services. Distribution revenues include $127 million (2012 – $127 million) received from the IESO related to the rural rate protection program. Distribution revenues also include $33 million (2012 – $28 million) received from the IESO related to the supply of electricity to remote northern communities.

In 2013, Hydro One purchased power in the amount of $2,477 million (2012 – $2,392 million) from the IESO-administered electricity market; $15 million (2012 – $10 million) from Ontario Power Generation Inc.; and $8 million (2012 – $7 million) from power contracts administered by the Ontario Electricity Financial Corporation.

In 2013, Hydro One incurred $12 million (2012 – $11 million) in Ontario Energy Board fees.

In 2013, revenues related to the provision of construction and equipment maintenance services with respect to the service level agreements with Ontario Power Generation Inc. were $9 million (2012 – $10 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $1 million in 2013 (2012 – $2 million).

In 2013, Hydro One received $34 million (2012 – $39 million) from the Ontario Power Authority (IESO effective January 1, 2015) related to CDM programs.

PILs and payments in lieu of property taxes are paid to the Ontario Electricity Financial Corporation, and dividends are paid to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the Ontario Energy Board's affiliate relationships code. Outstanding balances at period end are interest free and settled in cash.

At December 31, 2013, the Company held $250 million in Province of Ontario floating-rate notes with a fair value of $251 million (2012 – $251 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of Canadian dollars)	2013	2012
Due from related parties	197	154
Due to related parties(1)	(230)	(261)
Investment	251	251

(1) Included in due to related parties at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $217 million (2012 – $199 million).

Considerations of Current Economic Conditions

Effect of Load on Revenue

The Company's load, based on normal weather patterns, is expected to increase in 2015 due to economic growth in all sectors of the Ontario economy, partially offset by the load impact of CDM and embedded generation. Overall load growth due to the economy alone is forecasted to be approximately 1.9%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 0.6% and 0.4%, respectively. On the whole, load is expected to increase by approximately 0.9% in 2015. The Company's approved revenue requirement for 2015 has taken the negative load impact of CDM and embedded generation into account. A load growth below the Company's load forecast, included in its approved revenue requirement, would negatively impact the Company's financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which Hydro One's rates are based. The first component impacted by interest rates is the Company's return on equity. The Ontario Energy Board-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, Hydro One estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its return on equity would reduce Hydro One Networks Inc.'s transmission and distribution businesses' 2015 results of operations by approximately $20 million and $13 million, respectively. As interest rates decline, there is more risk of a decline in net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the Ontario Energy Board would impact the Company's results of operations.

Input Costs

In support of the Company's ongoing work programs, Hydro One is required to procure materials, supplies and services. To manage total costs, the Company regularly establishes security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and it also manages a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, the Company develops long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of its strategic sourcing practices, Hydro One does not foresee any adverse impacts on its business from current economic conditions in respect of adequacy and timing of supply and credit risk of its counterparties. Further, the Company has been able to realize significant savings through its strategic sourcing initiatives.

Pension Plan

During the six months ended June 30, 2015, Hydro One contributed approximately $89 million to its pension plan, compared to contributions of approximately $174 million made in the same period in 2014, and incurred $82 million in net periodic pension benefit costs, compared to $79 million incurred in the same period in 2014. Contributions of $174 million made during the six months ended June 30, 2014, included contributions for the balance of the 2014 year, whereas no pension plan contributions prepayments were made during the six months ended June 30, 2015.

In 2014, Hydro One contributed approximately $174 million to its pension plan, compared to contributions of approximately $160 million made in 2013, and incurred $158 million in net periodic pension benefit costs, compared to $287 million incurred in 2013. The Company currently estimates its total annual pension contributions to be approximately $174 million for 2015 and $175 million for 2016, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Actuarial valuations are required to be filed at least every three years. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. In 2014, the Company's pension plan experienced positive returns of approximately 12.3%, compared to approximately 17.9% in 2013.

As at December 31, 2014, the projected benefit obligation of the Company's pension plan was $7,535 million (December 31, 2013 – $6,576 million) and the fair value of plan assets was $6,299 million (December 31, 2013 – $5,731 million), giving rise to an unfunded status liability of $1,236 million (December 31, 2013 – $845 million). For more information regarding the funded status of the Company's pension plan, see note 15 of the audited consolidated financial statements of Hydro One Inc. as at and for the years ended December 31, 2014 and 2013 included elsewhere in this prospectus.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase, and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates–Employee Future Benefits" in this MD&A.

Risk Management

Hydro One has an Enterprise Risk Management ("**ERM**") Program that aims at balancing business risks and returns. A company-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with its strategic goals. The Company's ERM program helps it to better understand uncertainty and its potential impact on the Company's strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports the Company's Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While the Company's philosophy is that risk management is the responsibility of all employees, the Board is responsible for overseeing the Company's ERM system. The Audit Committee reviews the ERM framework for the Company and assesses the adequacy and completeness of the process for identifying and assessing the key risks facing the Company. The Audit Committee will also meet with the head of the Company's risk management function at least twice per year. The Board has, in the past, reviewed the Company's risk profile, which is the list of key risks prepared by senior management, and represents the greatest threats to meeting its strategic objectives. The Board committees review risks relevant to their mandate at every meeting.

The Company's President and Chief Executive Officer has ultimate accountability for risk management. The Company's leadership team provides senior management oversight of its risk portfolio and its risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

The Company's Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of Hydro One's business strategy, planning and objective setting. The Chief Financial Officer has specific accountability for ensuring that ERM processes are established, properly documented and maintained by the Company.

The Company's senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The Chief Financial Officer provides support to the committees of the Board of Directors, the President and CEO, the senior management team and key managers within the company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across the Company. Hydro One's internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, the Company's Board of Directors has taken on an enhanced role in the Company's risk governance structure. Each committee of the Board of Directors takes accountability for reviewing specific risks of the Company.

Key elements of the Company's ERM Program enable it to identify, assess and monitor its risks effectively. These include having an ERM policy and framework which communicates the Company's philosophy and process for risk management across the Company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance. In order to drive consistency throughout the risk identification and risk management processes, the Company uses a standard list of risk sources known as risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for risk assessments. All risk assessments in the Company start with this risk universe. The Company also uses standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and helps ensure a consistent basis for its risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

For an understanding of key risks and other potential risks of the Company, including non-financial risks, see "Risk Factors".

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing its accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. The Company has identified the following critical accounting estimates used in the preparation of its consolidated financial statements:

Revenues

The Company's monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of the Company's entity-wide system improvement project will allow Hydro One to use historical trends at a customer level to better estimate unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2015. Any changes in estimates will be accounted for prospectively.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The allowance for doubtful accounts on customer receivables is estimated by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment.

Regulatory Assets and Liabilities

The Company's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Company's regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to Ontario Energy Board deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the Ontario Energy Board, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the Ontario Energy Board will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

The Company 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.

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. 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. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

In April 2014, changes were made to the existing federal PCB regulations, which included the extension of the end-of-use deadline from 2014 to 2025 for equipment containing certain concentrations of PCBs. As a result of an annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to reduce its environmental liabilities by $20 million that included the impact of the PCB regulations amendment.

Employee Future Benefits

The Company's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to its current and retired employees. Employee future benefits costs are included in its labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2014 decreased to 4.00% from 4.75% used at December 31, 2013, in conjunction with decreases in bond yields over this period. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy. The expected long-term rate of return on pension plan assets for the year ending December 31, 2015 is 6.5%, consistent with the prior year.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects Hydro One's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 2.00% per annum as at December 31, 2013 to approximately 1.70% per annum as at December 31, 2014. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2014.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption at December 31, 2014 was updated to the final tables issued by the Canadian Institute of Actuaries (for public sector, with projection scale CPM-B and no adjustment due to pension size). As at December 31, 2013, the draft tables published by the Canadian Institute of Actuaries were used.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in a $23 million increase in 2014 interest cost plus service cost, and a $248 million increase in the year-end 2014 benefit liability.

Asset Impairment

Within the Company's regulated businesses, the carrying costs of most of its long-lived assets are included in the rate base where they earn an Ontario Energy Board-approved rate of return. Asset carrying values and the related return are recovered through Ontario Energy Board-approved rates. As a result, such assets are only tested for impairment in the event that the Ontario Energy Board disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2014 and 2013, no asset impairment had been recorded for assets within its regulated or unregulated businesses.

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company has concluded that goodwill was not impaired at December 31, 2014 and 2013.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that provides guidance on revenue recognition which depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This update is applicable to the Company for the years and interim periods beginning on January 1, 2017. The Company is currently assessing the impact of adoption of this accounting standards update on its consolidated financial statements.

In November 2014, the FASB issued an accounting standards update that provides guidance on accounting for hybrid financial instruments issued in the form of a share. This update is applicable to the Company for the years and interim periods beginning on January 1, 2016. Hydro One is currently assessing the impact of adoption of this accounting standards update on its consolidated financial statements.

In January 2015, the FASB issued an accounting standards update that eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this accounting standards update will have a significant impact on its consolidated financial statements.

In February 2015, the FASB issued an accounting standards update that provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company is currently assessing the impact of adoption of this accounting standards update on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. Upon adoption of this update, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued an accounting standards update that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this accounting standards update will have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company is currently assessing the impact of adoption of this accounting standards update on its consolidated financial statements.

PRE-CLOSING TRANSACTIONS

Hydro One Brampton Networks Inc.

As recommended in the final electricity sector report of the Council dated April 16, 2015, the Company understands that the Province intends to proceed with a sale or merger transaction involving Hydro One Brampton Networks Inc. In anticipation of that transaction, on August 31, 2015, Hydro One Inc. subscribed for additional shares of Hydro One Brampton Networks Inc. in order to repay certain short term debt owing to Hydro One Inc. and thereafter Hydro One Inc. declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton Networks Inc. In addition on that date, Hydro One Inc. reduced its stated capital by an amount equal to the fair market value of certain long term debt owing by Hydro One Brampton Networks Inc. to Hydro One

Inc. The subscription for additional shares, the dividend and the return of capital were authorized by the Province, the sole shareholder of Hydro One Inc., pursuant to a unanimous shareholder agreement dated April 16, 2015 that had removed the power of the directors of Hydro One Inc. to take action involving Hydro One Brampton Networks Inc. in connection with the transaction. The dividend was paid to the Province, at its direction, by transferring all of the issued and outstanding shares of Hydro One Brampton Networks Inc. to a company wholly owned by the Province and the return of capital was satisfied by transferring the indebtedness that was the subject of the return of capital to that same company at the direction of the Province. These transactions are separate from this offering.

Accordingly, Hydro One no longer owns any of the shares or indebtedness of Hydro One Brampton Networks Inc. and will not be a participant in or receive any proceeds from any sale or transaction involving Hydro One Brampton Networks Inc.

Prior to August 31, 2015, Hydro One Brampton Networks Inc. was operated by Hydro One as a stand-alone entity, with Hydro One providing certain management, administrative and smart meter network services to Hydro One Brampton Networks Inc. pursuant to existing service level agreements. These agreements will continue until the end of 2016 (except in the case of smart meter network services, which will continue until the end of 2017). Hydro One Brampton Networks Inc. has the right to renew these agreements (other than smart meter network services) for additional one-year terms to end no later than December 31, 2019. Additionally, on August 31, 2015, Hydro One Inc. and Hydro One Brampton Networks Inc. entered into a license agreement which permits Hydro One Brampton Networks Inc. to use the "Hydro One" name and related licensed marks. These agreements will terminate if the Province disposes of its interest in Hydro One Brampton Networks Inc., except in the case of the smart meter network services agreement, which is anticipated to continue for a transition period after the Province disposes of its interest in Hydro One Brampton Networks Inc.

Hydro One Inc. Credit Facilities

Hydro One Inc. currently has certain existing credit facilities available to it, including a $1.5 billion committed revolving standby credit facility (the "**Liquidity Facility**") with a syndicate of banks, which matures in June 2020. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources for Three and Six Month Periods". The Liquidity Facility is unsecured, and may be used for general corporate purposes, including meeting short-term funding requirements. Hydro One Inc. may draw on the Liquidity Facility as described in "– Recapitalization of Hydro One Networks Inc. and Dividend or Return of Capital to the Province" below.

On or prior to closing of this offering, it is anticipated that Hydro One Inc. will enter into a new credit agreement in order to provide for an additional new three-year senior, unsecured revolving term credit facility (the "**New Term Facility**") in the amount of $800 million. The New Term Facility will be a revolving credit facility to be used by Hydro One Inc. for working capital and general corporate purposes. Hydro One Inc. may draw on the New Term Facility as described in "– Recapitalization of Hydro One Networks Inc. and Dividend or Return of Capital to the Province" below. The New Term Facility will rank equally with any existing and future senior debt of Hydro One Inc.

The New Term Facility is expected to have customary covenants substantially similar to the covenants under the existing Liquidity Facility.

Hydro One Inc. Commercial Paper Program

Currently, Hydro One Inc. has a commercial paper program under which Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes (increased from $1.0 billion on October 9, 2015) with a term to maturity of less than 365 days which is supported by the Liquidity Facility.

Hydro One Limited Credit Facility

On or prior to closing of this offering, it is anticipated that Hydro One Limited will enter into a credit agreement with a syndicate of banks providing for a new operating credit facility (the "**Operating Credit Facility**") in the amount of $250 million. The Operating Credit Facility will be a revolving credit facility to be used by Hydro One Limited for working capital and general corporate purposes.

Recapitalization of Hydro One Networks Inc. and Dividend or Return of Capital to the Province

Certain steps will be taken to recapitalize Hydro One's subsidiary, Hydro One Networks Inc., and pay a dividend or make a return of capital to the Province in the amount of $800 million, rather than $1 billion as previously disclosed, reflecting a revised estimate of approximately $200 million in additional payments in lieu of taxes that are expected to be payable by Hydro One Inc. to the Ontario Electricity Financial Corporation. See "Departure Tax" and note 2C(iii) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus. These steps are expected to occur prior to the closing date of this offering, and are expected to include the following:

- Hydro One Inc., either through issuances of commercial paper or drawings under the Liquidity Facility or the New Term Facility, will make $800 million in cash available. The amount of the new borrowings for this step is expected to be approximately $800 million.
- Hydro One Inc. will use a portion of the $800 million in cash made available as described above to make an interest bearing loan to its wholly-owned subsidiary, Hydro One Networks Inc. in order to re-set the capital structure of Hydro One Networks Inc. for regulatory purposes to 60% debt and 40% equity, after accounting for the additional common shares of Hydro One Networks Inc. that will be issued pursuant to the last step referred to below under "– Pre-Closing Steps".
- Hydro One Networks Inc. will use the proceeds of the loan from Hydro One Inc. to either pay a dividend or make a return of capital to Hydro One Inc.
- Hydro One Inc. will use the proceeds received from Hydro One Networks Inc. and any amounts retained from the $800 million in cash made available to pay a dividend or make a return of capital to the Province in the amount of $800 million.

Pre-Closing Steps

Prior to the completion of this offering, Hydro One will complete a series of transactions that will result in, among other things, the acquisition by Hydro One Limited of all of the issued and outstanding shares of Hydro One Inc. and the issuance of new common shares and preferred shares of Hydro One Limited to the Province (the "**Pre-Closing Steps**"). The Province will then sell a portion of its common shares of Hydro One Limited pursuant to this offering. The following pre-closing steps are expected to occur prior to the closing date of this offering:

- Hydro One Inc. will purchase or redeem its existing preferred shares held by the Province for cancellation at a price equal to the redemption price of the preferred shares (being equal to approximately $323 million) which will be satisfied by the issuance to the Province of common shares of Hydro One Inc. having an aggregate fair market value equal to the price to be paid for the preferred shares.
- All of the issued and outstanding common shares of Hydro One Inc. will be acquired by Hydro One Limited in return for common shares of Hydro One Limited and Series 1 preferred shares of Hydro One Limited being issued to the Province. See "Description of Share Capital – Preferred Shares – Series 1 Preferred Shares and Series 2 Preferred Shares".
- As referred to under "Departure Tax", Hydro One Inc. and certain of its subsidiaries are required to pay the $2.6 billion "departure tax" to the Ontario Electricity Financial Corporation as a consequence of this offering. See "Departure Tax".
- In order to provide funding to support the departure tax payments referred to above, the Province, as shareholder, will subscribe for additional common shares of Hydro One Limited for an aggregate subscription price equal to the amount of the departure tax anticipated to be paid by Hydro One Inc. and its subsidiaries.
- The funds received by Hydro One Limited will be provided to certain subsidiaries of Hydro One Limited, including Hydro One Inc. and Hydro One Networks Inc., in order to allow those subsidiaries to pay their respective portions of the departure tax. These funds will be transferred to those subsidiaries by way of subscriptions for additional shares.
- Hydro One Networks Inc., as the subsidiary bearing the largest portion of the departure tax, will issue a significant number of additional shares to Hydro One Inc. in return for receiving funding to support the payment of its portion of the departure tax.
- The outstanding common shares of Hydro One Limited will be consolidated such that 595,000,000 common shares will be issued and outstanding immediately prior to the closing of this offering.

CORPORATE STRUCTURE

Incorporation and Office

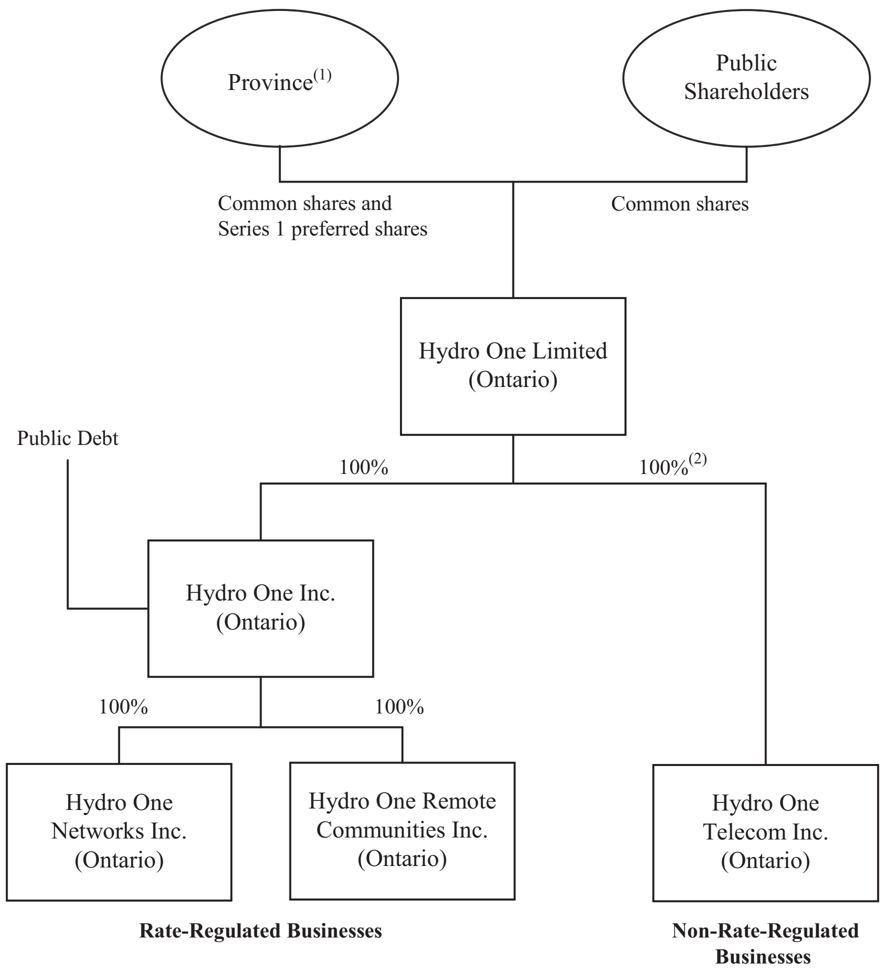
Hydro One Limited was incorporated on August 31, 2015 under the *Business Corporations Act* (Ontario) (the "**OBCA**"). Its registered office and head office is located at 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5.

Prior to the closing of this offering, the articles of Hydro One Limited will be amended to authorize the Series 1 preferred shares and Series 2 preferred shares, with the Series 1 preferred shares to be issued to the Province as part of the transactions described in "Pre-Closing Transactions – Pre-Closing Steps". See also "Description of Share Capital – Preferred Shares".

Hydro One Limited's principal subsidiary, Hydro One Inc., which acts as the holding company of Hydro One's rate-regulated businesses, was incorporated as Ontario Hydro Services Company Inc. by Articles of Incorporation dated December 1, 1998, under the OBCA. On May 1, 2000, it changed its name to Hydro One Inc.

Corporate Structure and Subsidiaries

The following is a simplified chart showing the organizational structure of Hydro One after giving effect to the transactions described in "Pre-Closing Transactions", this offering and certain post-closing transactions that involve the transfer of all of the issued and outstanding shares of Hydro One Telecom Inc. from Hydro One Inc. to another wholly-owned subsidiary of Hydro One Limited. This chart does not include all legal entities within Hydro One's organizational structure.



Notes:

(1) Following the closing of this offering and the other transactions described in "Principal and Selling Shareholder – Share Purchase Arrangements with the Province", it is expected that the Province will own approximately 85% of Hydro One Limited's common shares (approximately 84% if the Over-Allotment Option is exercised in full) and 100% of the outstanding Series 1 preferred shares.

(2) Will be indirectly held through a wholly-owned subsidiary of Hydro One Limited that will act as a holding company for Hydro One's non-rate-regulated businesses.

Certain of Hydro One's subsidiaries are described below:

- **Hydro One Inc.** – will act as a holding company for Hydro One's rate-regulated businesses. Its publicly-issued debt will continue to be outstanding.
- **Hydro One Networks Inc.** – will continue to be the principal operating subsidiary that carries on Hydro One's rate-regulated transmission and distribution businesses.
- **Hydro One Remote Communities Inc.** – will continue to generate and supply electricity to remote communities in northern Ontario.
- **Hydro One Telecom Inc.** – will continue to carry on Hydro One's non-rate-regulated telecommunications business.

DIVIDENDS

Dividend Policy

Hydro One Limited has not declared or paid any dividends since its incorporation and will not declare or pay any dividends prior to completion of this offering. The Board is expected to establish a dividend policy pursuant to which Hydro One Limited will pay a quarterly dividend, initially in the amount of $0.21 per common share. The annual amount of the dividend is anticipated to be approximately $500 million in the aggregate initially, based on a target payout ratio of 70% to 80% of net income. Assuming the closing of this offering occurs on November 5, 2015, the first dividend for the period from the closing of this offering to March 17, 2016 is expected to be paid on or about March 31, 2016 to shareholders of record on March 17, 2016. Dividends will be declared and paid in arrears. The amount and timing of any dividends payable by Hydro One Limited will be at the discretion of the Board and will be established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board may consider relevant. Hydro One intends to increase its debt as its rate base increases in order to maintain debt at 60% of its rate base and does not anticipate any increases in debt to fund the payment of dividends, although it may draw on its revolving credit facilities for general purposes. See "Risk Factors".

Dividend Reinvestment Plan

Following the closing of this offering and subject to the receipt of any required regulatory approvals, Hydro One Limited intends to adopt a dividend reinvestment plan pursuant to which resident Canadian holders of common shares will be entitled to elect to have all of the cash dividends of Hydro One Limited payable to them automatically reinvested in additional common shares, which will be either purchased on the open market or issued from treasury. The dividend reinvestment plan is currently intended to operate on a basis that does not result in significant dilution to holders of common shares.

DESCRIPTION OF SHARE CAPITAL

The following describes Hydro One Limited's share capital as it will exist immediately prior to the closing of this offering. The following description may not be complete and is subject to, and qualified in its entirety by reference to, the terms and provisions of Hydro One Limited's articles, as they may be amended from time to time.

Hydro One Limited's authorized share capital will consist of an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. Two series of preferred shares will be authorized for issuance prior to the closing of this offering: the Series 1 preferred shares and the Series 2 preferred shares. Immediately prior to the closing of this offering, there will be 595,000,000 common shares, 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Common Shares

Holders of common shares are entitled to receive notice of and to attend all meetings of shareholders, except meetings at which only the holders of another class or series of shares are entitled to vote separately as a class or series, and holders of common shares are entitled to one vote per share at all such meetings of shareholders. Hydro One Limited's common shares are not redeemable or retractable. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 preferred shares and Series 2 preferred shares, holders of common shares are entitled to receive dividends if, as, and when declared by the Board. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 preferred shares and Series 2 preferred shares, holders of common shares are also entitled to receive the remaining assets of Hydro One Limited upon its liquidation, dissolution or winding-up or other distribution of Hydro One Limited's assets for the purposes of winding-up its affairs. For a description of Hydro One Limited's dividend policy, see "Dividends – Dividend Policy".

The Voting Securities of Hydro One Limited, which include the common shares, are subject to share ownership restrictions under the Electricity Act and certain other provisions contained in the articles of Hydro One Limited related to the enforcement of those share ownership restrictions. The share ownership restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds Voting Securities solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities of Hydro One Limited. See "Governance and Relationship with Principal Shareholder – 10% Ownership Restriction".

Preferred Shares

Hydro One Limited may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Board is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Hydro One Limited expects to authorize for issuance the Series 1 preferred shares and the Series 2 preferred shares prior to the closing of this offering.

Subject to the OBCA, holders of Hydro One Limited's preferred shares or a series thereof are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One Limited except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited. The preferred shares are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares with respect to payment of dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited.

Series 1 Preferred Shares and Series 2 Preferred Shares

Prior to the closing of this offering, Hydro One Limited will issue $418 million of Series 1 preferred shares to the Province at a price of $25.00 per share. The existing preferred shares of Hydro One Inc. held by the Province will be cancelled. See "Pre-Closing Transactions – Pre-Closing Steps".

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares will be entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board, payable quarterly on the 20th day of November, February, May and August in each year. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One Limited prior to November 20, 2020, but will be redeemable by Hydro One Limited on November 20, 2020 and on November 20 every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will be redeemable by Hydro One Limited at a redemption price equal to $25.00 for each Series 2 preferred share redeemed if redeemed on November 20, 2025 or on November 20 every fifth year thereafter or $25.50 for each Series 2 preferred share redeemed if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

In the event of the liquidation, dissolution or winding-up of Hydro One Limited, or any other distribution of assets of Hydro One Limited for the purpose of winding-up its affairs, the holders of Series 1 preferred shares and Series 2 preferred shares will be entitled to receive $25.00 for each Series 1 preferred share and each Series 2 preferred share held by them, plus any unpaid dividends, before any amounts are paid or any assets of Hydro One Limited are distributed to holders of common shares and any shares ranking junior to the Series 1 preferred shares and Series 2 preferred shares. After payment of those amounts, the holders of Series 1 preferred shares and Series 2 preferred shares will not be entitled to share in any further distribution of the property or assets of Hydro One Limited.

Except as required by the OBCA, neither the holders of Series 1 preferred shares nor the holders of Series 2 preferred shares shall be entitled to receive notice of, or to attend meetings of shareholders of Hydro One Limited and shall not be entitled to vote at any such meeting, unless Hydro One Limited fails for eight quarters, whether or not consecutive, to pay in full the dividends payable on the Series 1 preferred shares or Series 2 preferred shares, as applicable, whereupon the holders of Series 1 preferred shares and Series 2 preferred shares, as applicable, shall become entitled to receive notice of and attend all meetings of shareholders, except class meetings of any other class of shares, and shall have one vote for each Series 1 preferred share or Series 2 preferred share held at such meetings, as applicable.

PRINCIPAL AND SELLING SHAREHOLDER

Ownership of Common Shares

The following table sets forth certain information regarding the Province's ownership of shares before and after completion of the transactions described in "Pre-Closing Transactions" and following this offering and the transactions described below in "– Share Purchase Arrangements with the Province".

Name	Number of common shares owned before the pre-closing transactions(1)	Number of common shares owned immediately after the pre-closing transactions(2)	Number of common shares to be sold in this offering(4)	Number of shares owned immediately following this offering and the share purchase arrangements(3)(4)	Percentage of shares owned immediately following this offering and the share purchase arrangements(3)(4)
Province of Ontario	100,000	595,000,000 common shares	81,100,000	Between 507,813,684 and 508,393,333 common shares	85%
				16,720,000 Series 1 preferred shares	100%

Notes:

(1) On August 31, 2015, Hydro One Limited issued 100,000 common shares to the Province at a subscription price of $1.00 per common share in connection with the incorporation of Hydro One Limited.

(2) Prior to the closing of this offering, Hydro One Limited will issue common shares to the Province at a price of $1.00 per common share as partial consideration for the acquisition of all of the issued and outstanding common shares of Hydro One Inc. by Hydro One Limited from the Province. In order to provide funding to support the departure tax payable as a consequence of this offering, the Province, as shareholder, will also subscribe for 2,600,000,000 additional common shares of Hydro One Limited at a subscription price of $1.00 per common share for an aggregate subscription price equal to the amount of the departure tax to be paid by Hydro One Inc. and its subsidiaries. The outstanding common shares of Hydro One Limited will then be consolidated such that 595,000,000 common shares will be issued and outstanding immediately prior to the closing of this offering. See "Pre-Closing Transactions", "Departure Tax", "Governance and Relationship with Principal Shareholder" and "Prior Sales".

(3) The Province has agreed to sell, immediately following the closing of this offering, additional common shares as described in "– Share Purchase Arrangements with the Province". These transactions are separate from this offering.

(4) Assuming no exercise of the Over-Allotment Option. If the Underwriters exercise their Over-Allotment Option in full, the Province will sell 89,250,000 common shares in this offering and the number of common shares owned by the Province immediately following this offering and the transactions described in "– Share Purchase Arrangements with the Province" will be between 499,663,684 and 500,243,333 common shares or approximately 84% of the total issued and outstanding common shares. Other than the Over-Allotment Option, there are no other securities convertible into common shares of Hydro One Limited.

The common shares owned by the Province will be owned beneficially or of record. To the knowledge of the Company, other than as described above: (i) there is no other person who beneficially owns, controls or directs, 10% or more of the common shares of Hydro One Limited, and (ii) immediately following the closing of this offering and the transactions described in "– Share Purchase Arrangements with the Province", there will be no other person who beneficially owns, controls or directs, 10% or more of the common shares of Hydro One Limited. The Electricity Act precludes any person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds Voting Securities solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, from owning, or exercising control or direction over, more than 10% of any class or series of Voting Securities, including common shares of Hydro One Limited.

Share Purchase Arrangements with the Province

Following the Province's announcement of its endorsement of the Council's recommendations to proceed with this offering, the Power Workers' Union expressed an interest in investing in the common shares, in order to invest in high quality jobs for Ontarians. In subsequent discussions, The Society of Energy Professionals indicated that it also wished to invest in common shares on a comparable basis to the Power Workers' Union. These unions have a significant number of members employed in the Ontario electricity sector and, in particular, at Hydro One and Ontario Power Generation Inc. The Province believes that the investment would be consistent with the purpose of this offering and will better align the interests of the members of the unions with the interests of other investors in Hydro One Limited.

The Province therefore agreed in September and October 2015 to sell, immediately following the closing of this offering, between 3,666,667 and 4,052,632 of its common shares to two trusts established for the benefit of the Power Workers' Union (the "**PWU Trusts**") and between 1,840,000 and 2,033,684 of its common shares to two trusts established for the benefit of The Society of Energy Professionals (the "**Society Trusts**" and, together with the PWU Trusts, the "**Trusts**"). In connection with these transactions, each of the Power Workers' Union and The Society of Energy Professionals will establish two trusts: one trust for the purchase of common shares via the loan described below and another trust for the purchase of common shares with funds provided by the relevant union. The Province will sell these common shares to the Trusts at the same price per share as the offering price in this offering. These common shares will be sold under an exemption from the prospectus requirements under applicable Canadian securities laws and not pursuant to this prospectus.

The Province also agreed, subject to conditions, to provide loans to one of the PWU Trusts and one of the Society Trusts in order to finance a portion of the share purchase and certain related expenses. The total principal amount of the loans will be $111 million: $75 million to one of the PWU Trusts and $36 million to one of the Society Trusts. Each borrower Trust will use its loan to acquire common shares and to pay for certain expenses incurred for professional services provided in relation to these transactions and the labour agreements. The loan amounts were agreed based on the number of members that each of the Power Workers' Union and The Society of Energy Professionals has employed at Hydro One and at Ontario Power Generation Inc. The non-borrower PWU Trust and non-borrower Society Trust will fund the purchase of the remaining common shares that the Province has agreed to sell with funds provided by the relevant union and not with a loan from the Province.

The loans will mature on the 15th anniversary of the closing of this offering. Interest on the principal amount will be payable quarterly in arrears at the Government of Ontario borrowing rate, plus 0.15%. Interest will be payable out of quarterly dividends received by the respective Trust on the common shares it has acquired with the proceeds of the loan, provided that if the dividends are insufficient to cover a particular interest payment when due, the interest payment may be deferred and added to the principal balance of the relevant loan. Each loan will be secured by the common shares purchased with that loan and held in the relevant Trust. Each loan will effectively be limited in recourse to the common shares acquired with that loan, because the borrower Trusts are not expected to own any material assets during the term of the loans other than the common shares that they acquired with the loans and permitted investments made with the proceeds of those common shares. The common shares purchased by the other Trusts with funds provided by the relevant union will not be subject to the loan security.

Each borrower Trust has agreed not to vote the common shares it holds from time to time so long as its respective loan amount remains outstanding. Each of the other Trusts has agreed not to dispose of the common shares that it acquired with funds provided by the relevant union for a period of at least one year after the purchase.

Accordingly, after closing of the transactions with the Trusts contemplated above, and after giving effect to the Pre-Closing Transactions and the completion of this offering, the number of common shares owned by the Province will be between 507,813,684 and 508,393,333 common shares (between 499,663,684 and 500,243,333 common shares if the Over-Allotment Option is exercised in full), representing approximately 85% of the issued and outstanding common shares (approximately 84% if the Over-Allotment Option is exercised in full).

Future Investments in Hydro One by First Nations and Métis Communities

In response to the Chiefs of Ontario's expression of First Nations' interest to own a portion of the Company, the Province has indicated that it is in discussions regarding potential equity participation by the First Nations. The Company understands that these discussions focus on facilitating equity participation for such communities through future offerings by the Province. These discussions are ongoing and are not expected to affect the number of shares available for purchase in this offering. In addition, the Métis Nation of Ontario has expressed an interest in dialogue with the Province in relation to this offering. The Province has indicated that it is also prepared to engage in a dialogue with the Métis in relation to broadened ownership of the Company.

DEPARTURE TAX

By virtue of being wholly owned by the Province, Hydro One is exempt from tax under the Tax Act and the *Taxation Act, 2007* (Ontario). However, under the Electricity Act, Hydro One is required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The payments in lieu of tax are, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Tax Act and the *Taxation Act, 2007* (Ontario) if it was not exempt from taxes under those statutes.

In connection with this offering, Hydro One's exemption from tax under the Tax Act and the *Taxation Act, 2007* (Ontario) will cease to apply. Under the Tax Act and the *Taxation Act, 2007* (Ontario), Hydro One will be deemed to have disposed of its assets immediately before it loses its tax exempt status for proceeds equal to the fair market value of those assets at that time. Hydro One will be liable to make a payment in lieu of tax under the Electricity Act in respect of the income and capital gains, calculated by reference to the Tax Act, that arise as a result of this deemed disposition. The amount payable is generally referred to as "departure tax".

In the context of a public offering of shares, and with the consent of the Minister of Finance, Hydro One will be authorized to pay to the Ontario Electricity Financial Corporation an amount that, in the Minister's opinion, reasonably approximates the amount of the departure tax that would be payable by Hydro One in respect of the deemed disposition of its assets. Hydro One has received a letter from the Minister of Finance confirming that the total amount of the departure tax payable by Hydro One is $2.6 billion. Prior to the completion of this offering, the Province, as shareholder, will subscribe for additional common shares of Hydro One Limited for an aggregate subscription price of $2.6 billion, which amount Hydro One will use to pay the applicable departure tax.

As a result of leaving the PILs regime and entering the corporate tax regime, Hydro One will recognize a deferred tax asset that is currently estimated in the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus to be $1,245 million due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. This estimated deferred tax asset was based on an estimated fair market value of Hydro One's net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion referred to above. This estimated fair market value of Hydro One's net assets was determined by Hydro One principally using a discounted cash flow approach for certain assets and an asset-based approach for other assets, and was used in calculating the amount of the departure tax payable that was agreed between Hydro One and the Province in early September 2015. The actual fair market value of Hydro One's net assets will be determined following pricing of this offering. The departure tax payable by Hydro One has been fixed at $2.6 billion, and will not be adjusted based on the fair market value of Hydro One's net assets as finally determined. See "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information". Management believes the deferred tax asset will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One. See note 2C(vi) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus for a presentation of the net cash savings that would have resulted for the periods shown if the transaction triggering the revaluation of the tax basis of Hydro One's fixed assets had occurred on January 1, 2014. Management believes that these net cash savings will not result in a corresponding reduction in its revenue requirement in future rate applications to the Ontario Energy Board. However, no determination has been made by the Ontario Energy Board and there can be no assurance that there will not be such a reduction. See "Risk Factors – Risks Relating to Hydro One's Business – Regulatory Risks and Risks Relating to Hydro One's Revenues".

Hydro One Inc. expects to pay the Ontario Electricity Financial Corporation approximately $200 million in additional payments in lieu of tax in connection with this offering. This is in addition to the departure tax payable of $2.6 billion. See note 2C(iii) of the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. included elsewhere in this prospectus.

CONSOLIDATED CAPITALIZATION

The following table sets out the consolidated capitalization of Hydro One Limited as at August 31, 2015, its date of incorporation, on an actual basis and on an adjusted basis to give effect to the transactions described under "Pre-Closing Transactions – Recapitalization of Hydro One Networks Inc. and Dividend or Return of Capital to the Province" and "Pre-Closing Transactions – Pre-Closing Steps".

This table should be read in conjunction with the financial statements, "Selected Consolidated Financial Information" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" appearing elsewhere in this prospectus.

	As at August 31, 2015	
	Actual	**Adjusted**
	(in millions)	
Debt		
Short-term debt(1)	—	$ 1,017
Operating Credit Facility(2)	—	$ —
Long-term debt(3)	—	$ 9,073
Noncontrolling interest subject to redemption	—	$ 21
Preferred shares(4)	—	$ 418
Equity		
Common shares(5)(6)(7)(8)	$0.1	$11,900
Retained earnings	—	$ 3,501
Accumulated other comprehensive loss	—	$ (9)
Noncontrolling interest	—	$ 50
Total capitalization	**$0.1**	**$25,971**

Notes:

(1) Represents issued and outstanding medium term notes and debentures of Hydro One Inc. due within the next twelve months.

(2) On or prior to closing of this offering, it is anticipated that Hydro One Limited will enter into a credit agreement with a syndicate of banks providing for the Operating Credit Facility in the amount of $250 million. The Operating Credit Facility will be a revolving credit facility to be used by Hydro One Limited for working capital and general corporate purposes. It is anticipated that the Operating Credit Facility will be undrawn immediately following the closing of this offering. See "Pre-Closing Transactions – Hydro One Limited Credit Facility".

(3) Includes commercial paper issued by Hydro One Inc. and drawings under the Liquidity Facility and New Term Facility as described in "Pre-Closing Transactions – Recapitalization of Hydro One Networks Inc. and Dividend or Return of Capital to the Province" and includes issued and outstanding medium term notes and debentures of Hydro One Inc. The Company intends that any commercial paper issued by Hydro One Inc. for such purposes would be replaced by long-term debt.

(4) On or prior to the closing of this offering, Hydro One Limited will issue 16,720,000 Series 1 preferred shares to the Province as partial consideration for the acquisition by Hydro One Limited of all of the issued and outstanding common shares of Hydro One Inc. from the Province. See "Pre-Closing Transactions – Pre-Closing Steps".

(5) On August 31, 2015, Hydro One Limited issued 100,000 common shares to the Province at a subscription price of $1.00 per common share in connection with the incorporation of Hydro One Limited.

(6) On or prior to the closing of this offering, Hydro One Limited will issue common shares at a price of $1.00 per common share to the Province as partial consideration for the acquisition by Hydro One Limited of all of the issued and outstanding common shares of Hydro One Inc. from the Province. See "Pre-Closing Transactions – Pre-Closing Steps".

(7) In order to provide funding to support the departure tax payable as a consequence of this offering, the Province, as shareholder, will subscribe for additional common shares of Hydro One Limited at a subscription price of $1.00 per common share for an aggregate subscription price equal to the amount of the departure tax to be paid by Hydro One Inc. and its subsidiaries. See "Pre-Closing Transactions – Pre-Closing Steps" and "Departure Tax".

(8) After completing the steps contemplated by notes (6) and (7) above, the outstanding common shares of Hydro One Limited will be consolidated such that 595,000,000 common shares will be issued and outstanding immediately prior to the closing of this offering. Adjusted common share amount assumes an offering price for Hydro One Limited's common shares offered under this prospectus of $20.00 per share.

CREDIT RATINGS OF SECURITIES

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. As of the date of this prospectus, Hydro One Inc.'s corporate credit ratings from designated rating organizations are as follows:

Rating Agency	Short-term debt	Long-term debt
Standard & Poor's Rating Services Inc. ("**S&P**")	A-1	A (stable)
DBRS Limited ("**DBRS**")	R-1 (middle) (under review with negative implications)	A (high) (under review with developing implications)
Moody's Investors Services Inc. ("**Moody's**")	Prime-1	A2 (negative)

As of the date of this prospectus, S&P has also assigned a long-term corporate credit rating to Hydro One Limited of A (stable).

Long-term debt is issued under Hydro One Inc.'s medium term note program authorized from time to time (currently expired but expected to be renewed by the end of 2015). Short-term debt is issued under Hydro One Inc.'s commercial paper program, under which it is currently authorized to issue up to $1.5 billion in short-term debt (increased from $1.0 billion on October 9, 2015). Hydro One Inc.'s commercial paper program is supported by its $1.5 billion Liquidity Facility.

The rating agencies rate long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D" ("C" in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P are in the third highest category and mean the obligor's capacity to meet its financial commitments and obligations is strong but is considered somewhat more susceptible to the adverse effects of changes in circumstances and adverse economic conditions than obligations in higher rated categories. S&P may modify the ratings from AA to CCC using a plus (+) or minus (-) sign to show relative standing within the major rating categories. Short-term debt obligations rated A-1 are in the highest category by S&P and means the obligor's capacity to meet its financial commitments on obligations is strong. Within this category, certain obligations are also designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations is extremely strong.

Long-term debt instruments which are rated in the A category by DBRS are in the third highest category and are considered to be of a good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category are considered to be vulnerable to future events, but qualifying negative factors are considered manageable. The "high" modifier indicates relative standing within this rating category by DBRS. DBRS' scale for commercial paper ratings range from the highest credit quality of R-1 to R-5. The R-1 and R-2 rating categories are further denoted by the subcategories "(high)", "(middle)", and "(low)". Short-term debt obligations rated R-1(middle) are considered of superior credit quality with very high capacity for the payment of short-term financial obligations as they fall due. The obligor is considered unlikely to be significantly vulnerable to future events.

Long-term debt instruments which are rated in the A category by Moody's are in the third highest category and are considered upper-medium grade and are subject to low credit risk. Moody's applies numerical modifiers 1, 2, and 3 to each generic rating classification from Aa to Caa. The modifier 2 indicates a ranking in the middle of that generic rating category. Short-term debt obligations rated Prime-1 is the highest category by Moody's and means the obligor has superior ability to repay short-term debt obligations.

The credit ratings assigned by S&P, DBRS or Moody's are not a recommendation to purchase, sell or hold Hydro One Inc.'s debt securities or Hydro One Limited's common shares and do not comment on market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant. Hydro One Inc. has made, and anticipates making, payments to each of S&P, DBRS and Moody's in connection with the confirmation of such ratings for purposes of the offering of medium term notes in the future, has made payments to S&P for ratings evaluation services in connection with this offering and has made payments to DBRS for ratings evaluation services in connection with the transfer of Hydro One Brampton Networks Inc. to a company wholly-owned by the Province. Hydro One Inc. has not made any payment to S&P, DBRS or Moody's in respect of any other services during the last two years.

GOVERNANCE AND RELATIONSHIP WITH PRINCIPAL SHAREHOLDER

Overview

Hydro One Limited's main subsidiary, Hydro One Inc., has been wholly-owned by the Province since the April 1999 reorganization of Ontario Hydro. See "Electricity Industry – Ontario's Electricity Industry". In April 2014, the Province formed the Council. The mandate of the Council was to review certain provincially-owned assets, including Ontario Power Generation Inc. and Hydro One Inc., and to recommend ways to maximize their value to the people of Ontario.

In its final electricity sector report released in April 2015, the Council recommended, among other things, that the Province should proceed with a partial sale of its interest in Hydro One Inc. to create a growth-oriented company centred in Ontario. The Council recommended that the partial sale occur by way of a public offering, with approximately 15% of the shares of Hydro One Inc. to be offered to the market initially. The Council recommended that the Province indicate its intention to retain its remaining shares after selling down to 40% ownership, and that the balance should be widely held with no other individual shareholder having more than a 10% holding. The report also recommended establishing a new governance framework for Hydro One Inc. as well as additional protections of the public's interest in Ontario's transmission and distribution systems. The Province has implemented certain of those recommendations through legislation, Hydro One Limited's articles and the Governance Agreement, as follows:

- On August 31, 2015, amendments to the Electricity Act were proclaimed into force, which are intended to maintain and support the Company's presence in Ontario by requiring the Company's head office and principal grid control centre to be maintained in Ontario, restricting the disposition of substantially all of its Ontario Energy Board-regulated transmission or distribution business, prohibiting any change to its jurisdiction of incorporation, adding a 10% ownership restriction with respect to Voting Securities and restricting the Province from selling Voting Securities if it would own less than 40% of the Voting Securities of any class or series as a result of the sale. See "– Presence in Ontario", "– 10% Ownership Restriction" and "– Maintenance of 40% Ownership".
- On June 4, 2015, amendments to various Ontario statutes came into force to provide for the appointment of an ombudsman for the Company and to transition the Company from oversight by various officers of the Legislative Assembly of Ontario. See "– Ombudsman" and "– Statutory Oversight and Transitional Provisions for Officers of the Assembly".
- Prior to the closing of this offering, the Province and Hydro One Limited will enter into the Governance Agreement to address the Province's role in the governance of Hydro One Limited, including the Province's right to nominate directors (all of whom must be independent of the Company and the Province), to grant the Province a pre-emptive right to acquire Voting Securities, and to provide for a confidentiality agreement relating to the confidential treatment of information furnished to the Province pursuant to the Governance Agreement or the Registration Rights Agreement. See "– Governance Agreement".
- Prior to the closing of this offering, the Province and Hydro One Limited will enter into the Registration Rights Agreement to provide the Province with the right to require Hydro One Limited to facilitate future secondary offerings of common shares or preferred shares owned or controlled by the Province. See "Province's Ownership of Common Shares and Preferred Shares – Registration Rights Agreement".

Presence in Ontario

Head Office in Ontario

The Electricity Act requires that the Company maintain its head office in Ontario, which will be the case if: (i) the principal executive office for the Company is located in Ontario; (ii) the Chief Executive Officer and substantially all of the officers with strategic decision-making or management authority for the Company principally perform their duties at that principal executive office or elsewhere in Ontario and are resident in Ontario; and (iii) substantially all of the strategic decision-making, corporate planning, corporate finance and other executive functions of the Company are carried out at that principal executive office or elsewhere in Ontario.

Principal Grid Control Centre in Ontario

The Electricity Act requires the Company to maintain, in Ontario, its centres of operation and control necessary for the control, monitoring and coordination of its transmission system that is regulated by the Ontario Energy Board and the control, monitoring and coordination of its distribution system that is regulated by the Ontario Energy Board.

Restriction on Disposition of Transmission or Distribution Businesses

The Electricity Act prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the Ontario Energy Board.

Incorporation in Ontario

The Electricity Act prohibits the Company from transferring its jurisdiction of incorporation to a jurisdiction outside of Ontario.

10% Ownership Restriction

The Electricity Act imposes share ownership restrictions on the Voting Securities. These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (the "**Share Ownership Restrictions**"). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

The articles of Hydro One Limited provide for comprehensive enforcement mechanisms that are applicable in the event of a contravention of the Share Ownership Restrictions. After the Board determines that a contravention has occurred, no person may vote the Voting Securities of the contravening persons or companies, dividends on the Voting Securities that are held in excess of the Share Ownership Restrictions are prohibited (and where the Board determines that the contravention was intentional, dividends on all of the Voting Securities held by the contravening persons or companies may be prohibited) and Hydro One Limited is required to send a notice requiring the sale of those excess Voting Securities. If such a required sale is not made, the exercise of any right or privilege attached to the Voting Securities will be prohibited and Hydro One Limited may sell or redeem the Voting Securities held in contravention and remit the net proceeds to the holder.

The Board may at any time require holders of, or subscribers for, Voting Securities and certain other persons to make declarations and provide related information with respect to ownership, direction, or control of Voting Securities and certain other matters relevant to the Share Ownership Restrictions. The Board may also require those holders or subscribers to produce documents, provide responses to written questions, and attend in person to answer questions concerning any declaration. Hydro One Limited is prohibited from accepting any subscription or issuing or registering a transfer of Voting Securities if it would result in a violation of the Share Ownership Restrictions.

Province's Ownership of Common Shares and Preferred Shares

The Province will own approximately 86% of Hydro One Limited's common shares after the pre-closing transactions and this offering (approximately 85% if the Over-Allotment Option is exercised in full). Thereafter, after closing of the transactions with the Trusts contemplated above, the Province will own approximately 85% of Hydro One Limited's common shares (approximately 84% if the Over-Allotment Option is exercised in full). See "Principal and Selling Shareholder". The Province has indicated that it intends to sell further common shares over time, until it holds approximately 40% of Hydro One Limited. See "Plan of Distribution" and "Risk Factors – Risks Relating to the Company's Relationship with the Province".

In addition, following the completion of the pre-closing transactions and this offering, the Province will own 100% of the outstanding Series 1 preferred shares of Hydro One Limited. See "Pre-Closing Transactions" and "Corporate Structure".

Maintenance of 40% Ownership

The Electricity Act restricts the Province from selling Voting Securities (including common shares of Hydro One Limited) if it would own less than 40% of the outstanding number of Voting Securities of that class or series after the sale. If as a result of the issuance of additional Voting Securities by Hydro One Limited, the Province owns less than 40% of the outstanding number of Voting Securities of any class or series, the Province must, subject to the approval of the Lieutenant Governor in Council and the necessary appropriations from the Legislature, take steps to acquire as many Voting Securities of that class or series as are necessary to increase the Province's ownership to not less than 40% of the outstanding number of Voting Securities of that class or series. The manner in which, and the time by which, the Province must acquire these additional Voting Securities will be determined by the Lieutenant Governor in Council.

The Province has been granted pre-emptive rights by Hydro One Limited to assist it in meeting its ownership requirements under the Electricity Act as described under "– Governance Agreement – Pre-emptive Rights".

45% Acquisition Limit

The Province has agreed in the Governance Agreement not to acquire previously issued Voting Securities if after that acquisition, the Province would own more than 45% of any class or series of Voting Securities (including common shares of Hydro One Limited). This restriction does not apply to the acquisition by the Province of Voting Securities as a result of the enforcement by the Province of any security interest securing payment of debt obligations owing to the Province or to certain acquisitions of Voting Securities by entities related to the Province or by third party managed funds or as passive investments. This restriction also does not require the Province to sell any of the common shares of Hydro One Limited that it currently owns, nor does it limit the Province from acquiring Voting Securities on an issuance by Hydro One Limited, including pursuant to the exercise by the Province of its pre-emptive right. See "– Governance Agreement – Pre-emptive Rights".

Provision of Financial Information to the Province and the Auditor General of Ontario

As the Province will remain a major shareholder of Hydro One Limited, it is expected that the Company's financial results will continue to be included in the Province's financial statements. For so long as this is the case, pursuant to the *Financial Administration Act* (Ontario), the Company must provide information to the Province for the sole purpose of the Province's preparation of its consolidated financial statements set out in the provincial public accounts and any quarterly consolidated financial statements. In addition, for so long as this is the case, pursuant to the *Auditor General Act* (Ontario), the Company and its auditors must also provide the Auditor General of Ontario with information necessary or relevant for the Auditor General of Ontario to prepare her or his report on the consolidated financial statements of the Province for inclusion in the provincial public accounts. The Company is not required to provide any of this information to the Province or the Auditor General of Ontario if it relates to a period for which the Company has not yet disclosed to the public its audited or unaudited financial statements.

Registration Rights Agreement

Prior to the closing of this offering, the Province and Hydro One Limited will enter into the Registration Rights Agreement. Pursuant to the Registration Rights Agreement, Hydro One Limited grants the Province the right, from time to time while the Province is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, to require Hydro One Limited to file, at the expense of the Province (except for internal expenses of Hydro One Limited or other expenses that Hydro One Limited would have incurred even in the absence of such a request), one or more prospectuses and take other procedural steps as may be reasonably necessary to facilitate a secondary offering in Canada of all or any portion of the common shares or preferred shares ("**shares**") held by the Province (a "**demand registration**").

Hydro One Limited can defer a demand registration for up to a maximum of 60 days if the Board determines in good faith that circumstances currently exist which make it in the best interests of Hydro One Limited to do so. These circumstances are either: (i) that the effect of the filing of a prospectus would reasonably be expected to materially interfere with or require the public disclosure of any material corporate development or plan (including any material financing, securities offering, acquisition, disposition, restructuring or merger or other transaction involving Hydro One Limited or any of its subsidiaries); or (ii) that there exists at the time material non-public information relating to Hydro One Limited, (a) the disclosure of which would be reasonably likely to be adverse to Hydro One Limited, or (b) where Hydro One Limited has a bona fide business purpose for keeping that information confidential. In addition, Hydro One Limited shall not be obligated to effect a demand registration more than four times in any 12-month period.

If Hydro One Limited proposes to undertake a Canadian public offering by prospectus, the Province is entitled, while it is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, to include shares owned by it as part of that offering, provided that the underwriters may reduce the number of shares proposed to be sold if in their reasonable judgment all of the shares proposed to be offered by Hydro One Limited and the Province may not be sold in an orderly manner within a price range reasonably acceptable to Hydro One Limited. In that case, the shares to be sold will be allocated pro rata between Hydro One Limited and the Province based on their relative proportionate number of shares requested to be included in the offering. Hydro One Limited and the Province will share the expenses of the offering (except for internal expenses of Hydro One Limited) in proportion to the gross proceeds they each receive from the offering.

Hydro One Limited also agrees to extend the foregoing provisions to facilitate U.S. registered offerings of shares of Hydro One Limited held by the Province, if Hydro One Limited in the future files a registration statement for the distribution of shares to the public in the United States.

Hydro One Limited also agrees to use commercially reasonable efforts to assist, at the Province's expense (except for internal expenses of Hydro One Limited), the Province in any sale by it of shares of Hydro One Limited pursuant to an exemption from the prospectus requirements, in the preparation of an offering memorandum and other documentation and by facilitating due diligence by the prospective buyer.

Hydro One Limited and the Province also agree to enter into customary agreements, including "lock-up" agreements, on customary market terms in connection with such transactions. Hydro One Limited also agrees to certain indemnification and contribution covenants in favour of the Province and any underwriters involved in such transactions.

Governance Agreement

The purpose of the Governance Agreement is to prescribe the role of the Province, as a holder of Voting Securities, in the governance of Hydro One Limited. Although the Governance Agreement does not address all aspects of the governance of Hydro One Limited (for a description of the governance of Hydro One Limited more generally, see "Directors and Management of the Company"), it comprehensively deals with, and limits, the role of the Province in that governance. It describes the principles that govern how Hydro One Limited will be managed and operated, including that the Province, in its capacity as a holder of Voting Securities, will engage in the business and affairs of Hydro One Limited as an investor and not as a manager. It also contains commitments by the Province restricting the exercise of its rights as a holder of Voting Securities.

The Governance Agreement specifically addresses the following matters:

- The governance principles under which Hydro One Limited and its subsidiaries will be managed and operated.
- The nomination of directors, which includes: (i) the requirement for a fully independent board of directors (other than the Chief Executive Officer), and (ii) the maximum number of directors that may be nominated by the Province.
- The election and replacement of directors.
- Approvals requiring a special resolution of the directors.
- Restrictions on the right of the Province to initiate fundamental changes.
- Pre-emptive rights provided to the Province with respect to future issuances of Voting Securities by Hydro One Limited.
- Acquisition limits with respect to the Province's acquisition of outstanding Voting Securities.

Governance Principles

The Governance Agreement provides that the business and affairs of Hydro One Limited will be managed and operated in accordance with the following principles:

- Hydro One Limited will maintain corporate governance policies, procedures and practices consistent with the best practices of leading Canadian publicly listed companies, having regard to Hydro One Limited's ownership structure and the Governance Agreement.
- The Board, which will be independent of both the Company and the Province (other than the Chief Executive Officer), is responsible for the management of or supervision of the management of the business and affairs of Hydro One Limited, including, subject to applicable law, having full authority in respect of:
  - corporate governance;
  - the appointment, termination, supervision and compensation of the Chief Executive Officer, Chief Financial Officer and other senior officers of Hydro One Limited;

    - remuneration of directors;
    - strategic planning and direction;
    - risk management;
    - capital structure;
    - Hydro One Limited's dividend policy; and
    - Hydro One Limited's annual business plan and budget.
- With respect to its ownership interest in Hydro One Limited, the Province will engage in the business and affairs of Hydro One Limited as an investor and not a manager, and the Province intends to achieve its policy objectives through legislation and regulation, as it would with respect to any other utility operating in Ontario.

The governance principles do not restrict the Province in any way: (i) in relation to the regulation of the Company, including by the Ontario Energy Board; (ii) in relation to system planning by the IESO; (iii) in relation to the enforcement of the laws of Ontario applicable to the Company or the enactment, promulgation or amendment of such laws; or (iv) in respect of any communication regarding the Company by an individual in his or her capacity as a member of the Legislative Assembly of Ontario, if made in the Legislative Assembly of Ontario or in another public forum in relation to the enforcement, promulgation or enactment of laws in Ontario or in relation to Ontario regulatory policy. They also do not restrict the exercise by the Province of its rights as a holder of Voting Securities, including its rights to vote any Voting Securities in its sole interest, except as expressly provided for in the Governance Agreement. See "Risk Factors – Risks Relating to the Company's Relationship with the Province."

Nomination of Directors

The Governance Agreement establishes qualification standards for director nominees, provides for the number of directors that each of the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee may nominate and establishes a process for confirming nominees. The Governance Agreement recognizes that the Board is to be a fully independent board, with all of the members of the Board independent of both the Company and the Province, with the exception of the Chief Executive Officer.

<u>Director Qualification Standards</u>

General

The Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee have agreed to nominate individuals as directors who are of high quality and integrity and who have:

- significant experience and expertise in business or that is applicable to business,
- served in a senior executive or leadership position,
- broad exposure to and understanding of the Canadian or international business community,
- skills for directing the management of a company, and
- motivation and availability,

in each case to the extent appropriate for a business of the complexity, size and scale of the business of Hydro One Limited and on a basis consistent with the highest standards for directors of Canada's leading public companies.

Independence

Each director nominee must be independent of Hydro One Limited within the meaning of Ontario securities laws governing the disclosure of corporate governance practices and independent of the Province, other than the Chief Executive Officer. A director will be independent of the Province if he or she would be independent of Hydro One Limited within the meaning of Ontario securities laws governing the disclosure of corporate governance practices if the Province and each Specified Provincial Entity (as provided in the Governance Agreement) were treated as Hydro One Limited's parent under that definition, but excluding, in the case only for the directors named in this prospectus, any prior relationship that ended before August 31, 2015. In addition, he or she may not be an employee or official of the Province or any Specified Provincial Entity, either: (i) currently or, (ii) within the last three years, but for (ii), excluding in the case only for the directors named in this prospectus, any prior relationship that ended before August 31, 2015. In addition, all director nominees must meet the requirement of applicable securities and other laws and any exchange on which Voting Securities are listed. A majority of the Board must be resident Canadians (as defined in the OBCA) and neither the Province nor the Nominating, Corporate Governance, Public Policy & Regulatory Committee will nominate any person as a director if as a result of that nominee being elected or appointed, this requirement would not be met. However, each director named in this prospectus is qualified to be a director of Hydro One Limited on the Closing Date, whether or not he or she satisfies the foregoing director qualification standards on the Closing Date. See "Directors and Management of the Company – Independence of the Board of Directors".

No director nominee may be proposed by the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee to replace a current director if, taking into account selection criteria identified by the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee for new directors, the Board would not collectively satisfy the Board's skills matrix, the Diversity Policy and any other policy relating to the composition of the Board forming part of Hydro One's governance standards.

If the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee nominates an individual who is already a director of Hydro One Limited at the time of the nomination, that person will be treated as meeting the director qualification standards unless there has been a material change in that individual's circumstances that would affect whether she or he would continue to meet those standards. See "Directors and Management of the Company – Independence of the Board of Directors".

Number of Directors

Under the articles of Hydro One Limited, the Board will consist of no fewer than 10 and no more than 15 directors, with the initial Board consisting of 15 directors until the first annual meeting of shareholders after closing of the offering. See "Directors and Management of the Company". The Governance Agreement requires that the articles of Hydro One Limited must at all times provide for this minimum and maximum number. The Board will determine from time to time the number of directors of Hydro One Limited within that minimum and maximum.

Board Nominees

The nominees to be proposed for election to the Board by Hydro One Limited at annual meetings of shareholders will be determined as follows:

- The Chief Executive Officer will be nominated.
- The Province will be entitled to nominate that number of nominees equal to 40% of the number of directors to be elected (rounded to the nearest whole number).
- The Nominating, Corporate Governance, Public Policy & Regulatory Committee will nominate the remaining directors.

If, however, the Province ceases to own Voting Securities to which are attached 40% of the votes that may be cast on the election of directors at a meeting of shareholders and the Province does not subsequently acquire Voting Securities sufficient to meet that ownership threshold by the next annual meeting nomination deadline following the second anniversary of the Province first ceasing to meet that ownership threshold, then until the Province again meets that ownership threshold, the number of Directors that the Province may nominate will be proportionate to the number of votes that the Province may cast on the election of directors. For this purpose, an annual meeting nomination deadline is the date that is 60 days prior to the date by which Hydro One Limited is required to mail proxy solicitation materials for an upcoming annual meeting.

Board Nomination Process

The Province and representatives of the Nominating, Corporate Governance, Public Policy & Regulatory Committee will meet after each annual meeting of shareholders to discuss expected upcoming departures from the

Board (whether due to resignation, retirement or otherwise). In this discussion, the Province and representatives of the Nominating, Corporate Governance, Public Policy & Regulatory Committee will consider the impact on the Board of those departures and identify selection criteria for director nominees to replace departing directors to ensure that the Board will collectively continue to comply with the Governance Agreement and satisfy the Board's skills matrix, the Diversity Policy and any other policy relating to the composition of the Board forming part of Hydro One's governance standards. The representatives of the Nominating, Corporate Governance, Public Policy & Regulatory Committee will also recommend to the Province individuals that the Nominating, Corporate Governance, Public Policy & Regulatory Committee has identified as potential candidates for nomination to the Board. The Province shall have no obligation to nominate any of the recommended individuals as one of its director nominees. This meeting would be expected to occur within 60 days of each annual meeting of shareholders.

The Province and representatives of the Nominating, Corporate Governance, Public Policy & Regulatory Committee will hold further meetings to continue to discuss expected upcoming departures from the Board and proposed replacement nominees under consideration. These additional meetings would be expected to occur within 120 days of each annual meeting of shareholders.

Subsequent to these meetings, each of the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee will notify the other of its proposed director nominees. They must do so by no later than the date that is 60 days prior to the date by which proxy solicitation materials must be mailed for Hydro One Limited's next annual meeting of shareholders.

If the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee receives a nomination from the other of a person who is not then a director of Hydro One Limited at the time of the nomination or who is then a director but whose circumstances have materially changed in a way that would affect whether she or he would continue to meet the director qualification standards as described under "– Governance Agreement – Nomination of Directors – Director Qualification Standards", then the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee, as the case may be, will have ten business days to confirm or reject that nominee. The Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee may reject a nominee only on the basis that the nominee does not meet those director qualification standards.

If a director nominee of the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee is rejected, then the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee will be entitled to nominate additional candidates until a nominee is confirmed by the other. If no replacement nominee is confirmed for a director who was expected to depart from the Board and that director does not resign, that director shall be re-nominated.

The Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee will use commercially reasonable efforts to confirm director nominees prior to the date by which proxy solicitation materials must be mailed for the purposes of Hydro One Limited's next annual meeting of shareholders. If insufficient nominees are confirmed by that date, then the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee will consider alternatives so that each nominates the number of directors each is entitled to nominate at that annual meeting. These alternatives may include reducing the number of directors to be elected at that annual meeting or delaying the annual meeting so that sufficient nominees may be confirmed.

If there are disputes as to whether a particular director nominee satisfies the director qualification standards as described under "– Governance Agreement – Nomination of Directors – Director Qualification Standards", either the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee may request that the dispute be resolved by arbitration.

Election and Replacement of Directors

The Governance Agreement provides for how:

- the Province will vote with respect to director nominees, including its nominees and those of the Nominating, Corporate Governance, Public Policy & Regulatory Committee,
- the Province may vote at contested elections,
- the Province may seek to replace the Board by withholding votes or voting for removal, and
- Board vacancies will be filled.

Voting on Director Elections

At any meeting of shareholders to elect directors, the Province is required to vote in favour of the nominees nominated as described under "– Governance Agreement – Nomination of Directors – Board Nominees and – Board Nomination Process" except in the case of contested director elections and where the Province seeks to replace the Board in accordance with the Governance Agreement by withholding votes or voting for removal. See "– Governance Agreement – Election and Replacement of Directors – Contested Elections," "– Right to Withhold Votes" and "– Province's Right to Replace the Board".

Contested Elections

At any meeting of shareholders to elect directors of Hydro One Limited at which there are more nominees for directors than there are directors to be elected, the Province may vote its Voting Securities in its sole discretion (including to vote in favour of other candidates instead of the Province's nominees), except that the Province will vote in favour of the election of the Chief Executive Officer as a director.

Right to Withhold Votes

The Province is required under the Governance Agreement to vote in favour of all director nominees of Hydro One Limited. That obligation is subject, however, to the Province's overriding right to withhold from voting in favour of all director nominees and its right to seek to remove and replace the entire Board, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In the case of an annual meeting of shareholders, the Province will notify Hydro One Limited of its intent to withhold from voting in favour of director nominees prior to the date by which proxy solicitation materials must be mailed for the purposes of that annual meeting.

Depending on the number of withheld votes a director nominee receives at a meeting of shareholders at which directors are to be elected, that director nominee may be required to tender his or her resignation to the Board in accordance with Hydro One Limited's majority voting policy. In this circumstance, the Board shall take whatever actions it determines are appropriate in the circumstances, including accepting resignations sequentially after replacement directors are identified and confirmed in accordance with the Governance Agreement, accepting some but not all resignations until sufficient replacement directors have been identified and confirmed in accordance with the Governance Agreement, calling a shareholders' meeting and accepting the resignations only upon the election of their replacements at that meeting, not accepting the resignations until the next annual meeting of shareholders, or rejecting the resignations. See "Directors and Management of the Company". However, for so long as the Province holds Voting Securities sufficient for it to withhold at least 50% of the votes that may be cast at that meeting of shareholders, the Province's withholding of votes will be sufficient to ensure that each of the directors with the exception of the Chief Executive Officer and, at the discretion of the Province, the Chair, are required to tender their resignation to the Board in accordance with Hydro One Limited's majority voting policy.

Province's Right to Replace the Board

The Province may at any time notify Hydro One Limited that it intends to request that Hydro One Limited hold a meeting of shareholders for the purposes removing all of the directors in office, including those nominated by the Province, with the exception of the Chief Executive Officer and, at the sole discretion of the Province, the Chair (a "**Removal Notice**").

If the Province gives Hydro One a Removal Notice, then the Chair shall coordinate the establishment of an ad hoc nominating committee comprising each of the five largest beneficial owners of Voting Securities known to the Company, excluding the Province, willing to provide representatives to serve on that committee. If at least three beneficial owners of Voting Securities are not willing to provide representatives to serve on the ad hoc nominating committee within 30 days of the Province giving a Removal Notice, then the individuals that the Province proposes to nominate as replacement directors, as described in the next paragraph, will serve as the ad hoc nominating committee.

The Province and the ad hoc nominating committee will identify and confirm replacement directors to be nominated at the shareholders' meeting pursuant to a process substantially equivalent to that described under "– Governance Agreement – Nomination of Directors – Board Nomination Process", with the ad hoc nominating committee taking the place of the Nominating, Corporate Governance, Public Policy & Regulatory Committee. For clarity, each replacement director nominee must meet the same qualification standards under the Governance

Agreement as for any director nominee, including the fact that all of them, other than the Chief Executive Officer, in each case, must be independent of Hydro One Limited within the meaning of Ontario securities laws governing the disclosure of corporate governance practices and be independent of the Province. See "– Governance Agreement – Nomination of Directors – Director Qualification Standards." Hydro One Limited will call the shareholders' meeting once the replacement director nominees are confirmed pursuant to this process, and will hold the shareholders' meeting within 60 days of this confirmation.

At the shareholders' meeting, the Province will vote in favour of removing the current directors with the exception of the Chief Executive Officer and, at the Province's discretion, the Chair, and will vote in favour of the independent director nominees described in the preceding paragraph.

From the time that the Province delivers a Removal Notice, the directors will, in exercising their fiduciary duties, take into account the Province's intention to cause a new Board to be constituted and the desirability that the actions of the current Board not interfere with the ability of a new Board to exercise its responsibility to oversee the business and affairs of Hydro One Limited in accordance with Hydro One Limited's governance principles. See "– Governance Agreement – Governance Principles".

The voting results of the shareholders' meeting will determine which individuals are elected as directors. However, for so long as the Province holds more than 50% of the outstanding common shares (and, depending on the number of shares represented at the meeting, possibly where the Province holds less than 50% of the outstanding common shares), the Province's votes will be sufficient to remove the current directors with the exception of the Chief Executive Officer and, at the Province's discretion, the Chair, and to replace them with the new Board as described above.

Filling Board Vacancies

If a vacancy on the Board arises, then a replacement will be nominated by the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee, whichever nominated the departing director, and approved by the other in accordance with a process that is substantially equivalent to the process described under "– Governance Agreement – Nomination of Directors – Board Nomination Process". For clarity, each replacement director nominee must meet the same qualification standards under the Governance Agreement as for any director nominee, including the fact that all of them, other than the Chief Executive Officer, in each case, must be independent of Hydro One Limited within the meaning of Ontario securities laws governing the disclosure of corporate governance practices and be independent of the Province. For this purpose, until the first meeting of shareholders to consider the election of directors that is held after the completion of this offering, the Province has designated Ian Bourne, Marc Caira, George Cooke, Kathryn Jackson, Jane Peverett and Gale Rubenstein as its nominees.

If the Chief Executive Officer ceases to be Chief Executive Officer for any reason, the new Chief Executive Officer appointed to take his or her place will fill that vacancy on the Board.

Subsidiary Governance

Subject to applicable law, the board of directors of each of Hydro One Inc. and Hydro One Networks Inc. will be constituted to have the same members as the Board unless the Board determines otherwise.

Company to Cause Compliance

Any obligations of the Board, the Nominating, Corporate Governance, Public Policy & Regulatory Committee, the Chair or any other representative of Hydro One Limited provided for in the Governance Agreement are deemed to be obligations of Hydro One Limited and Hydro One Limited will ensure those obligations are complied with. If Hydro One Limited is unable to comply with the Governance Agreement without being in breach of its by-laws, Hydro One Limited is required to amend its by-laws to enable the performance of its obligations under, and its compliance with, the terms of the Governance Agreement. Any such amendment to Hydro One Limited's by-laws must be submitted to the shareholders for approval at the next meeting of shareholders.

Board Approvals Requiring a Special Resolution of the Directors

<u>Annual Confirmation of Chair and Chief Executive Officer</u>

The appointment of a new Chair at any time must be approved by a resolution of the Board passed by at least two-thirds of the votes cast at a meeting of the directors, or consented to in writing by all of the directors (a "**Special Board Resolution**"). The Chair will be nominated and confirmed annually by a Special Board Resolution at the first meeting of the Board after each annual meeting of shareholders. If the Board does not confirm the Chair at that meeting by a Special Board Resolution, then the Board will remove the Chair as soon as practicable and appoint a new Chair. The Chair may also be removed between annual confirmation meetings by a majority of the votes cast at a meeting of the directors.

The appointment of a new Chief Executive Officer at any time must be approved by a Special Board Resolution. The Chief Executive Officer must be confirmed annually by a Special Board Resolution at the first meeting of the Board after each annual meeting of shareholders. If the Board does not confirm the Chief Executive Officer at that meeting by a Special Board Resolution, then the Board shall remove the Chief Executive Officer as soon as practicable and appoint a replacement Chief Executive Officer. The Chief Executive Officer may also be removed between annual confirmation meetings by a majority of the votes cast at a meeting of the directors.

<u>Changes in Governance Standards</u>

Hydro One Limited has established a number of governance standards, some of which are specified in the Governance Agreement to be "Hydro One's governance standards". As such, no addition, supplement or amendment to these specified governance standards can be effective unless approved by a Special Board Resolution. The governance standards that are subject to this special approval requirement include the Board's skills matrix, the Ombudsman's Mandate, the Diversity Policy and the Majority Voting Policy, the Corporate Governance Guidelines, the mandates of the Board and its committees, position descriptions for the Chief Executive Officer, the Chair, the directors and committee chairs, and the Stakeholder Engagement Policy.

Restrictions on Province's Right to Initiate Fundamental Changes

The Province has agreed not to initiate a fundamental change to Hydro One Limited (as defined in Part XIV of the OBCA), including not to initiate any arrangement or amalgamation involving Hydro One Limited or any amendment to the articles of Hydro One Limited. The Province may, however, vote its Voting Securities as it sees fit in the event any fundamental change is initiated by Hydro One Limited or another shareholder of Hydro One Limited.

Restrictions on Province Acting Jointly or in Concert

The Province has agreed not to act jointly or in concert with any person in connection with the exercise of that person's rights as a holder of Voting Securities in a manner that the Province would be prohibited from directly doing itself. The Province is not, however, restricted from soliciting proxies to vote a person's Voting Securities in a particular manner, if the Province is itself permitted to vote its Voting Securities in that manner. Any pension plan or related pension fund which the Province or any "public entity" (as defined in the *Financial Administration Act* (Ontario)) establishes, sponsors, administers or contributes to will not be treated as a joint actor of the Province except to the extent the Province solicits the administering entity or governing body of the pension plan or related pension fund to take a particular action or step.

Pre-emptive Rights

Hydro One Limited has granted to the Province a pre-emptive right to acquire additional Voting Securities as part of future offerings by Hydro One Limited of Voting Securities. If Hydro One Limited proposes to issue Voting Securities in the future, whether pursuant to a public offering or a private placement, Hydro One Limited must notify the Province of the proposal at least 30 days in advance and must offer the Province the right to purchase up to 45% of the Voting Securities being offered. The offer must also specify the proposed outside date for completing the proposed offering, which cannot be more than 60 days from the date of the offer. If the offer is being delivered in connection with a proposed best-efforts or fully underwritten public offering (including an offering proposed on a "bought deal" basis) through an agent or underwriter, the offer may include a size range and may state that the actual price per Voting

Security will be the offering price agreed to by Hydro One Limited in the agency agreement, bid letter or underwriting agreement, as the case may be, relating to the offering. Otherwise, the offer must specify the price at which the Voting Securities are to be issued and the number of Voting Securities the Province is entitled to purchase. If the offer to the Province is in connection with a proposed best-efforts or fully underwritten public offering (including an offering proposed on a "bought deal" basis), then the Province may specify in its response a maximum price or range of prices at which it will purchase Voting Securities. Otherwise, the Province must specify in its response the number of Voting Securities it wishes to purchase. Any Voting Securities not purchased by the Province pursuant to the offer may be purchased by any other person pursuant to the proposed offering. If Hydro One Limited is continuing in good faith to contemplate a proposed offering after the outside date, it may extend the outside date by up to four months. After that date, including any extensions, Hydro One Limited may not deliver an offer for a further proposed offering for at least 90 days.

The pre-emptive right also applies with respect to any proposed issuance by Hydro One Limited of securities convertible into or exchangeable for Voting Securities. The pre-emptive right does not apply with respect to an issuance of Voting Securities or securities convertible into or exchangeable for Voting Securities: (i) pursuant to employee or director compensation plans existing on the date of the Governance Agreement or plans adopted after the date of the Governance Agreement that comply with the rules of the TSX and, if required, have been approved by the TSX; (ii) pursuant to any dividend re-investment arrangement of the Company that is consistent with dividend reinvestment arrangements of other publicly traded utilities in Canada (including as to discount rates) and that does not include a cash purchase option; (iii) pursuant to a rights offering that is open to all shareholders of Hydro One Limited; or (iv) pursuant to any business combination, take-over bid, arrangement, asset purchase transaction or other acquisition of assets or securities of a third party.

Confidentiality of Information Provided to the Province

The Province and Hydro One Limited will enter into a confidentiality agreement pursuant to which the Province will agree to keep confidential information provided to the Province pursuant to the Governance Agreement and/or the Registration Rights Agreement, subject to certain customary exceptions. The confidentiality obligations of the Province will, subject to certain procedural requirements, permit disclosure by the Province where it is required by applicable law, including pursuant to the *Freedom of Information and Protection of Privacy Act* (Ontario). The Company will similarly agree to keep confidential certain information provided by the Province pursuant to the Governance Agreement and/or the Registration Rights Agreement, subject to certain customary exceptions.

The Province will also agree to use such information only for certain specified purposes relating to the exercise or enforcement of the Province's rights under the Governance Agreement and the Registration Rights Agreement, and in connection with the evaluation, oversight and management of the Province's investment in Hydro One Limited, including the exercise of its rights as a shareholder, in each case in accordance with the Governance Agreement, the Registration Rights Agreement and applicable law. The confidentiality agreement will also require the Province to, among other things, have instituted reasonable internal controls to restrict disclosure of non-public material information of Hydro One Limited and Hydro One Inc. and to restrict trading in their securities by the Province and persons who may receive access, directly or indirectly from the Province, to non-public material information about Hydro One Limited and/or Hydro One Inc.

Termination of Governance Agreement

The Governance Agreement provides that it may be terminated only with the mutual agreement of the Province and Hydro One Limited. If there are changes in circumstances in the future that impact the original purpose and intention of the Province and Hydro One Limited in entering into the Governance Agreement, the Province and Hydro One Limited will cooperate in good faith to amend the Governance Agreement to reflect those changes in circumstances.

Termination of Existing Shareholder Declarations and Resolutions

As the sole shareholder of Hydro One Inc., the Province has from time to time directed corporate actions or strategies through unanimous shareholder declarations that removed authority from the board of Hydro One Inc. In the past, the Province has made unanimous shareholder declarations that, among other things: (i) restricted the rights, powers and duties of the Hydro One Inc. board in relation to the off-shoring of certain jobs and the outsourcing of certain services; (ii) prevented Hydro One Inc. from seeking cost recovery through the regulatory process for upgrades for certain transmission stations from either Micro FIT or Small FIT generators; and (iii) restricted the rights, powers and duties of the Hydro One Inc. board with respect to whether, how and when to proceed with the Hydro One Brampton Networks Inc. transaction. Immediately prior to the closing of the offering, the Province will terminate all existing unanimous shareholder declarations relating to Hydro One Inc. and its subsidiaries. Following the completion of the offering, the Province will no longer be able to make such shareholder declarations.

Ombudsman

The Electricity Act requires the Company to appoint an ombudsman to act as a liaison with customers and to establish procedures for the ombudsman to inquire into and report to the Board on matters raised with the ombudsman by or on behalf of customers. These procedures are set out in a written mandate (the "**Ombudsman's Mandate**") together with, among other things, the ombudsman's other duties and responsibilities. On October 22, 2015, the board of directors of Hydro One announced the appointment of Fiona Crean to the role of Ombudsman for the Company. Her appointment will be effective November 17, 2015 and the Office of the Ombudsman is expected to be operative in the first quarter of 2016.

Statutory Oversight and Transitional Provisions for Officers of the Assembly

Pursuant to legislation which came into force in 2015, Hydro One Inc. and its subsidiaries ceased to be subject to a number of Ontario statutes that apply to entities owned by the Province, including the *Broader Sector Public Accountability Act, 2010,* the *Broader Public Sector Executive Compensation Act, 2014*, the *Financial Accountability Officer Act, 2013*, the *Freedom of Information and Protection of Privacy Act*, the *Management Board of Cabinet Act*, the *Ombudsman Act*, the *Trillium Trust Act, 2014*, the *Public Sector Expenses Review Act, 2009* and the *Public Sector Salary Disclosure Act, 1996*. Hydro One Limited will similarly not be subject to those statutes.

In addition, the Company's obligations under the *Financial Administration Act* (Ontario) and the *Auditor General Act* (Ontario) have been limited to those described under "– Province's Ownership of Common Shares and Preferred Shares – Provision of Financial Information to the Province and Auditor General of Ontario".

The Auditor General of Ontario, the Financial Accountability Officer, the Information and Privacy Commissioner and the Provincial Ombudsman can continue to exercise certain of their powers with respect to the Company. The Information and Privacy Commissioner may also issue orders with respect to those matters until June 4, 2016.

Ontario Electricity Financial Corporation Indemnity

At the time that Hydro One Inc. and certain of its subsidiaries acquired their respective assets from the former Ontario Hydro pursuant to the transfer orders under the Electricity Act, as described under "Interests of Management and Others in Material Transactions – Relationship with the Province and Other Parties – Transfer Orders", the Ontario Electricity Financial Corporation agreed to indemnify Hydro One Inc. and those subsidiaries with respect to:

(a) the failure of the transfer orders to transfer to Hydro One Inc. or those subsidiaries any asset, right or thing or any interest in any asset, right or thing related to their business (the "**Hydro One Entitlements**"); and

(b) adverse claims or interests of third parties (including the Crown) to Hydro One Entitlements or based on any deficiency or lack of title in respect of any Hydro One Entitlement.

The indemnity only applies when the total value of all claims exceeds $10 million. The indemnity also contains certain thresholds and exclusions. This indemnity contains, among other matters, an exclusion for any claim related to any Aboriginal title or rights or the absence of a permit, right of way easement or similar right in respect of lands forming part of a Reserve. The indemnity is guaranteed by the Province.

Hydro One Inc. is required to pay the Ontario Electricity Financial Corporation an annual fee for the indemnity until the indemnity terminates. Hydro One Inc. and its subsidiaries have not made any claim under the indemnity since it was put in place in 1999. The parties, with the consent of the Minister of Finance, have agreed to terminate the indemnity effective October 31, 2015. Any claims for which Hydro One Inc. provides notice to the Ontario Electricity Financial Corporation by the termination date will be covered by the indemnity, subject to the restrictions and exclusions in the indemnity.

DIRECTORS AND MANAGEMENT OF THE COMPANY

Directors and Executive Officers

The following table sets forth information regarding the directors and executive officers of Hydro One Limited at the closing of this offering. Each of the directors was first appointed on August 31, 2015 and is a director of Hydro One Limited as of the date of this prospectus. Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Name, Province or State and Country of Residence	Age	Position/Title	Independent[1]	Principal Occupation[2]	Committees
Mayo Schmidt Ontario, Canada	58	President and Chief Executive Officer and Director		President and Chief Executive Officer, Hydro One Limited	—
Michael Vels Ontario, Canada	54	Chief Financial Officer		Chief Financial Officer, Hydro One Limited	—
Alexander (Sandy) Struthers Ontario, Canada	56	Chief Operating Officer		Chief Operating Officer, Hydro One Inc.	—
David Denison Ontario, Canada	63	Director and Chair of the Board	Yes	Chair, Hydro One Limited	—
Ian Bourne[3] Alberta, Canada	67	Director	Yes	Chair, Ballard Power Systems Inc.	Human Resources Committee (Chair); Nominating, Corporate Governance, Public Policy & Regulatory Committee
Charles Brindamour Ontario, Canada	45	Director	Yes	Chief Executive Officer, Intact Financial Corporation	Audit Committee; Human Resources Committee
Marcello (Marc) Caira[3] Ontario, Canada	61	Director	Yes	Vice-Chairman, Restaurant Brands International Inc	Human Resources Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
Christie Clark Ontario, Canada	61	Director	Yes	Corporate Director	Human Resources Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
George Cooke[3] Ontario, Canada	62	Director	Yes	President, Martello Associates Consulting / Chair, OMERS Administration Corporation	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee
Margaret (Marianne) Harris Ontario, Canada	57	Director	Yes	Corporate Director	Human Resources Committee; Health, Safety, Environment and First Nations & Métis Committee (Chair)
James Hinds Ontario, Canada	58	Director	Yes	Corporate Director	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee

Name, Province or State and Country of Residence	Age	Position/Title	Independent[(1)]	Principal Occupation[(2)]	Committees
Kathryn Jackson[(3)] Pennsylvania, United States	58	Director	Yes	Corporate Director	Nominating, Corporate Governance, Public Policy & Regulatory Committee; Health, Safety, Environment and First Nations & Métis Committee
Roberta Jamieson Ontario, Canada	62	Director	Yes	President and Chief Executive Officer, Indspire	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee
Frances Lankin Ontario, Canada	61	Director	Yes	Corporate Director	Audit Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
Philip Orsino Ontario, Canada	61	Director	Yes	Consultant and Corporate Director	Audit Committee (Chair); Nominating, Corporate Governance, Public Policy & Regulatory Committee
Jane Peverett[(3)] British Columbia, Canada	57	Director	Yes	Corporate Director	Human Resources Committee, Nominating, Corporate Governance, Public Policy & Regulatory Committee (Chair)
Gale Rubenstein[(3)] Ontario, Canada	62	Director	Yes	Partner, Goodmans LLP	Human Resources Committee; Health, Safety, Environment and First Nations & Métis Committee

Notes:

(1) See "– Independence of the Board of Directors".

(2) See "– Biographical Information" for the five year history of each director and executive officer.

(3) These directors have been designated as the Province's nominees for the purpose of filling any vacancies arising until the first meeting of shareholders to consider the election of directors after the completing of this offering. See "Governance and Relationship with Principal Shareholder – Governance Agreement – Election and Replacement of Directors – Filling Board Vacancies".

Biographical Information

The following includes a brief profile of each of the executive officers and directors of Hydro One Limited, which include a description of their present occupation and their principal occupations for the past five years.

Mayo Schmidt

Mr. Mayo Schmidt is the President and Chief Executive Officer of both Hydro One Limited and Hydro One Inc. and a director of both Hydro One Limited and Hydro One Inc. Prior to joining Hydro One, Mr. Schmidt served as President, Chief Executive Officer, and director at Viterra Inc., the global food ingredients company from January 2000 to December 2012. Early in his career, Mr. Schmidt held a number of key management positions of increasing responsibility at General Mills, Inc. until he joined ConAgra Grain, Canada as President and spearheaded ConAgra's expansion. He was promoted to Executive Vice-President, Domestic and International Operations with KBC Trading and Processing Company, a global subsidiary of ConAgra Inc. In 2000, he was appointed Chief Executive Officer of Saskatchewan Wheat Pool, the leading Canadian agriculture corporation and predecessor to Viterra Inc. In 2005, he was named President, joined the Board of Directors, and led Saskatchewan Wheat Pool to become a listed public corporation. In 2007, he led a $2.0 billion acquisition of Agricore United, then a $2.2 billion acquisition of ABB, Australia's leading agriculture corporation. Mr. Schmidt is a transformative leader with a track record of improving operations and efficiencies while building a performance-driven culture. He was the architect of Viterra Inc.'s transformation from a regional agriculture and food business to a global leader, with Viterra Inc. more than tripling revenue to almost $12 billion. Under Mr. Schmidt's leadership, the total enterprise value of Viterra Inc. increased from under $200 million in 2000 to $7.48 billion. Mr. Schmidt currently sits on the Board of Directors of Agrium Inc., a global agriculture firm and the Global Transportation Hub Authority. He was a member of the Canadian Council of Chief Executive Officers, Executive Committee Member of The Conference Board of Canada, Trustee of The Conference Board Inc. USA, and Harvard's Private and Public, Scientific, Academic and Consumer Food Policy Group, and is on Washburn University's Foundation board of Trustees. Mr. Schmidt received his B.B.A. from Washburn in 1980.

Michael H. Vels

Mr. Michael Vels is the Chief Financial Officer of both Hydro One Limited and Hydro One Inc. Prior to joining the Company, Mr. Vels served as Maple Leaf Foods Inc.'s Chief Financial Officer (2004 to 2014), responsible for overseeing the company's finance, mergers and acquisitions, information technology and communications functions, and, in 2014, served as the Chief Transition Officer, responsible for leading the restructuring of management and back office functions of the Company. From 1991 to 2004, Mr. Vels took on increasing roles and responsibility at Maple Leaf Foods. While at Maple Leaf Foods, Mr. Vels drove business transformation and productivity gains in information technology and shared services. He guided Maple Leaf Foods through numerous M&A transactions, including divestitures totaling approximately $3 billion, realizing premium value for shareholders. Prior to 1991, he worked in public accounting in Canada and mergers and acquisitions in the United Kingdom. Mr. Vels brings considerable executive level experience in public company governance, debt and equity capital raising, mergers and acquisitions and information technology. Mr. Vels currently serves as Director of Canada's National Ballet School and formerly served on the board of directors for Canada Bread Company, Ltd. (2007-2014) and Country Style Food Services Inc. (2007-2009). He is a past member of the OSC Continuous Disclosure Advisory Committee. Mr. Vels earned a Bachelor of Accountancy from the University of Witwatersrand, in Johannesburg, South Africa. He is a Chartered Accountant (South African Institute of Chartered Accountants).

Alexander (Sandy) Struthers

Mr. Alexander (Sandy) Struthers is the Chief Operating Officer and Executive Vice President Strategic Planning of Hydro One Inc. and Hydro One Networks Inc. Mr. Struthers previously served as Hydro One Inc.'s Chief Financial Officer and Chief Administrative Officer (2013-2014), overseeing the company's finance, regulatory and corporate support functions. Mr. Struthers first joined Hydro One Inc. in 2000 as a Finance Director responsible for mergers and acquisitions and has since held a number of senior management positions as Chief Financial Officer (2009-2012), and as Vice President and Chief Information Officer (2004-2008), where he was accountable for the information technology organization and information technology strategy. Prior to joining the Company, Mr. Struthers was a partner in the Corporate Finance group of a national accounting firm. Mr. Struthers holds a Masters of Business Administration from York University and a Bachelor of Commerce (Honours) from Queen's University. He is a member of the Institute of Corporate Directors, a Chartered Professional Accountant and a member of the Institute of Chartered Accountants of Ontario, and a past member of the Canadian Institute of Chartered Business Valuators.

David Denison, O.C., FCPA, FCA

Mr. David Denison was appointed the Chair of the Board of Hydro One Inc. on April 16, 2015. Mr. Denison is also a Corporate Director and previously served as President and Chief Executive Officer of the Canada Pension Plan Investment Board from 2005 to 2012. Prior to that, Mr. Denison was President of Fidelity Investments Canada Limited. Mr. Denison is a Director of the Royal Bank of Canada, Bell Canada, Allison Transmission and serves as Vice-Chair of Sinai Health Systems. He had previously also served as Chair of the Board of Bentall Kennedy Limited Partnership. He is also a member of the Investment Board and International Advisory Committee of the Government of Singapore Investment Corporation, the International Advisory Council of China Investment Corporation, the World Bank

Treasury Expert Advisory Committee and the University of Toronto Investment Advisory Committee. In April 2014, Mr. Denison was appointed a member of the Council whose mandate was to review and identify opportunities to modernize government business enterprises. Mr. Denison earned Bachelor degrees in mathematics and education from the University of Toronto and is a Chartered Professional Accountant and a Fellow of the Institute of Chartered Accountants of Ontario. Mr. Denison was appointed an Officer of the Order of Canada on June 30, 2014.

Ian Bourne, ICD.D, F.ICD

Mr. Ian Bourne is the Chair of the Board of Directors of Ballard Power Systems, Inc. (2006-present), a global leader in proton exchange membrane fuel cell technology, and a member of the Board of Directors of the Canada Pension Plan Investment Board, Canadian Oil Sands Limited, Wajax Corporation, and the Canadian Public Accountability Board. He is also the former Chair of SNC-Lavalin Group Inc. (2013-2015) and was a director from 2009 to 2015 during which time he also served as that company's Interim Chief Executive Officer from March 2012 to October 2012. Mr. Bourne has also held a variety of senior financial and executive roles in Canada and internationally with a number of Canadian corporations including: GE Canada, Inc. (1969-1992) where he served as Chief Financial Officer; Canada Post Corporation (1992-1997) where he served as Senior Vice-President and Chief Financial Officer; and TransAlta Corporation (1998-2005) where he served as Executive Vice President and Chief Financial Officer and as President of TransAlta Power LP between 1998-2006. Mr. Bourne has been active in serving a variety of community based organizations including the Calgary Philharmonic Orchestra, The Glenbow Museum, and The Calgary Foundation. He holds a Bachelor of Commerce degree from Mount Allison University and is a Fellow of the Institute of Corporate Directors.

Charles Brindamour

Mr. Charles Brindamour is the Chief Executive Officer of Intact Financial Corporation, Canada's largest provider of home, auto and business insurance. Under his leadership, Intact Financial Corporation became an independent and widely-held Canadian company in 2009 and engineered, two years later, the largest acquisition in the history of the property and casualty insurance industry in the country. With a market capitalization of more than $12 billion, Intact Financial Corporation ranks among the largest companies listed on the TSX. Mr. Brindamour began his career with Intact in 1992 as an actuary and held over the years a number of progressive management positions. He also served in management and executive roles in Europe with ING Groep, Intact's former majority shareholder. Upon his return to Canada in 1999, he led the company's acquisition, strategic planning and capital management functions. Two years later, he became Senior Vice-President of Personal Lines and, in 2004, he was appointed Executive Vice-President, responsible for underwriting, claims, planning, corporate development and investor relations. In 2007, he became Chief Operating Officer, a position he held until his appointment as President and Chief Executive Officer in January 2008. A graduate of Laval University in Actuarial Sciences, Mr. Brindamour is also an Associate of the Casualty Actuarial Society. Mr. Brindamour is a board member of Intact Financial Corporation, of the C.D. Howe Institute, and of the Insurance Bureau of Canada where he was Chair for the past four years. He is also a member of the Advisory Committee of the Climate Change Adaptation Project, an initiative of the University of Waterloo. Mr. Brindamour is a member of the Campaign Cabinet of the CHU Sainte-Justine, Co-Chair of the Grande Campagne de financement de l'Universite Laval, and a past member of the Campaign Cabinet of the United Way of Greater Toronto, where he chaired a number of insurance industry campaigns.

Marcello (Marc) Caira

Mr. Marc Caira is a director and Vice-Chairman of the Board of Directors of Restaurant Brands International Inc., a multinational quick service restaurant company formed by the merger of Tim Hortons Inc. and Burger King Worldwide Inc. He is also a director of the Minto Group. Prior to his appointment as Vice Chairman in December 2014, Mr. Caira was President and Chief Executive Officer of Tim Hortons Inc. (July 2013-December 2014). During his approximate 37-year career within the food and beverage industry, Mr. Caira also held senior management and executive roles with both Nestlé S.A. and Parmalat North America, Inc. Beginning his career with Nestlé Canada in 1977, Mr. Caira took on positions of increasing responsibility becoming Vice-President of Foodservice (1990-1996), and President – Foodservice & Nescafé Beverages (1997-2000). In 2000, he joined Parmalat Canada, Inc. as Chief Operating Officer and assumed the role of President and CEO of Parmalat North America in 2004. In 2006, Mr. Caira returned to Nestlé S.A. in Switzerland as a member of the Executive Board and as Chief Executive Officer of Nestlé Professional until his return to Canada in 2013. Mr. Caira holds a Diploma in Marketing Management from Seneca College, Toronto (1977) and is a graduate of the Director Program at The International Institute for Management Development, Lausanne, Switzerland.

Christie J.B. Clark, FCA, FCPA

Mr. Christie Clark is a Corporate Director and serves as a member of the Board of Directors of Loblaw Companies Limited, Air Canada, and Choice Properties Real Estate Investment Trust. He served as the Chief Executive Officer and Senior Partner of PricewaterhouseCoopers LLP from July 2005 to July 2011. Prior to being elected Chief Executive Officer, Mr. Clark served as National Managing Partner and as a member of the firm's Executive Committee from 2001 to 2005. Mr. Clark is a Fellow Chartered Professional Accountant, and in addition to his public company board memberships, he is on the Board of Alpine Canada and a member of the Advisory Council of Queen's University School of Business. Mr. Clark holds a Bachelor of Commerce degree from Queen's University and a Master of Business Administration degree from the University of Toronto.

George L. Cooke

Mr. George Cooke is President, Martello Associates Consulting, a business strategy consulting firm, and on October 1, 2013 he was appointed as Chair of the Board of Directors of the OMERS Administration Corporation. OMERS is one of Canada's largest pension funds and OMERS Administration Corporation is responsible for pension services and administration, investments, and plan valuation. Mr. Cooke is the former President and CEO, The Dominion of Canada General Insurance Company ("The Dominion"), a position he held from 1992 when he joined the company to August 2012. In August 2012, Mr. Cooke retired from his role as President of The Dominion and continued to hold the position of Chief Executive Officer of the company until December 31, 2012. Prior to his appointment with The Dominion, Mr. Cooke was Vice-President (Ontario Division), S.A. Murray Consulting Inc. (a government relations consulting firm) between 1990 and 1992. His previous experience includes Special Advisor, Policy to the Ontario Deputy Premier and Treasurer (1989-1990), General Manager, Ontario Automobile Insurance Board (1988-1989), and positions with the Ontario Energy Board (1980-1988). Mr. Cooke obtained a Bachelor of Arts degree (Hons.) in Political Studies (1975) and a Masters of Business Administration degree (1977) from Queen's University. He also holds an Honorary Doctor of Laws degree (1999) from Assumption University in Windsor. Mr. Cooke was a member of the Board of Directors of The Dominion (1992-2013), the Insurance Bureau of Canada (1992-2013), E-L Financial Corporation (1992-2012), Empire Life (1992-2002) and Atomic Energy of Canada Limited (1995-1999), and he was also Executive Vice-President with E-L Financial Corporation Limited (1992-2013). He is currently the Chair of the Board of Directors of CANATICS (Canadian National Insurance Crime Services). Mr. Cooke has been a Director of Hydro One Inc. since January 26, 2010.

Margaret (Marianne) Harris

Ms. Marianne Harris is a Corporate Director and the Chair of the Board of Directors of the Investment Industry Regulatory Organization of Canada (IIROC) and a member of its Finance, Audit and Risk Committee. Prior to becoming a Corporate Director, Ms. Harris was Managing Director of the Bank of America Merrill Lynch and President, Corporate and Investment Banking for Merrill Lynch Canada Inc. (2010 – 2013). She has extensive corporate and investment banking experience gained from over 29 years of advisory work in the U.S. and Canada. During her career, Ms. Harris has worked on a wide range of assignments including mergers and acquisitions, takeover defense, unsolicited offers, demutualizations, initial public offerings, secondary equity offerings, and a number of other advisory and corporate finance mandates. Prior to joining Merrill Lynch in 2000, Ms. Harris was Head of the Financial Institutions Group at RBC Capital Markets. In addition to her position as Chair of IIROC, she is a member of the Board of Sun Life Financial Inc. and Sun Life Assurance Company of Canada. Ms. Harris is also a Director and Chair of the Investment Committee of the Princess Margaret Cancer Foundation Board, a Director of the Dean's Advisory Council at the Schulich School of Business (York University), and a member of the Advisory Council of the Hennick Centre for Business and Law (York University). Ms. Harris holds a Masters of Business Administration degree from the Schulich School of Business, a Juris Doctor degree from Osgoode Hall Law School (York University) and a B.Sc. (Honours) from Queen's University.

James Hinds

Mr. James Hinds is a retired investment banker, having specialized in public equity markets underwriting and advice for media, industrial, mining and real estate companies. Mr. Hinds previously served as Managing Director of TD Securities Inc. and has also held positions with CIBC Wood Gundy Inc. and Newcrest Capital Inc. Mr. Hinds was the past Chair of the IESO and has also served as Chair of the former Ontario Power Authority Board of Directors (2010-2014) until its merger with the IESO effective January 1, 2015. Prior to joining the Ontario Power Authority

Board, he served as a Director on and as Chair of the IESO Board of Directors (2005-2010). A native of Sudbury, Ontario, Mr. Hinds received a Bachelor of Arts degree from Victoria University at the University of Toronto, a Master of Business Administration from the Wharton School of Business at the University of Pennsylvania, and a law degree from the University of Toronto.

Kathryn J. Jackson, Ph.D

Dr. Kathryn Jackson is a Corporate Director and former Senior Vice President and Chief Technology Officer of RTI International Metals Inc. (2014 – 2015). In her capacity as RTI's former Top Scientist, Dr. Jackson's responsibilities included oversight of all advanced metallurgical technology, product and process innovation, including additive manufacturing activities. She also served as Head of Overall Research and Development Activities and as a corporate director at RTI. Prior to joining RTI, Dr. Jackson was Senior Vice President and Chief Technology Officer at Westinghouse Electric Company where she was responsible for research and development as well as environmental sustainability initiatives. Dr. Jackson has also held various positions at the Tennessee Valley Authority, including Executive Vice President of River System Operations and Environment, and Corporate Environmental Officer. She also worked for Alcoa Corporation as a technology forecaster and was a post-doctoral fellow at the National Academy of Engineering. Dr. Jackson serves on the Board of Directors of Portland General Electric and previously served as Chair of the Independent System Operator New England. She is also an advisor to Carnegie Mellon University's Engineering School and the Complex Engineered Systems program, and is a member of the advisory board of the Carnegie Mellon Electricity Industry Center. Dr. Jackson received a Doctorate and a Master's degree in Engineering and Public Policy from Carnegie Mellon University. She also holds a Master's degree in Industrial Engineering Management from the University of Pittsburgh and a Bachelor's degree in Physics from Grove City College.

Roberta L. Jamieson

Ms. Roberta Jamieson is a Mohawk woman from the Six Nations of the Grand River Territory in Ontario, where she still resides. In November 2004, she was appointed President and Chief Executive Officer of Indspire, Canada's premiere Indigenous-led charity, and Executive Producer of the Indspire Awards, a nationally broadcast gala honoring Indigenous achievement. Indspire's annual award disbursements have increased seven-fold since Ms. Jamieson's appointment. She has extended Indspire's youth career conferences to all regions of Canada and launched a recognition program for the education of Indigenous students. Ms. Jamieson also led the development of the K-12 Indspire Institute, a virtual resource centre focused on increasing high school completion rates and K-12 success. Under Ms. Jamieson's leadership, Indspire launched an unprecedented $20 million fundraising campaign in 2013 to support Indspire's Building Brighter Futures: Bursaries and Scholarships Awards program. Ms. Jamieson has enjoyed a distinguished career of firsts. She was the first First Nations woman to earn a law degree; the first non-parliamentarian appointed an ex-officio member of a House of Commons Committee; the first woman Ombudsman of Ontario (1989-1999); and in December 2011, she was the first woman elected Chief of the Six Nations of the Grand River Territory. She also served as Commissioner of the Indian Commission of Ontario from 1986 to 1989. She was also a Director of the Ontario Power Generation Inc. Board of Directors (2012 – 2015). Ms. Jamieson has earned numerous awards, including the National Aboriginal Achievement Award (Law and Justice 1998); the Indigenous Bar Association's highest award, Indigenous Peoples Council Award (IPC); the Council of Ontario Universities' 2014 David C. Smith Award; and 24 honorary degrees. She also serves as a member of the Elections Canada Advisory Board and has been named three times to the Women's Executive Network's Top 100 list. Ms. Jamieson was appointed a Member of the Order of Canada in 1994.

Hon. Frances L. Lankin, P.C., C.M.

Hon. Frances Lankin P.C., C.M. is a former President and CEO of the United Way – Toronto (2001-2010) and a former Member of Provincial Parliament for the Toronto (Ontario) riding of Beaches – East York (1990-2001). Ms. Lankin is a recognized leader in the non-profit sector and has been widely honoured for her contributions to the community, including Honorary Doctorate of Laws degrees from Queen's University and Ryerson University, and an Honorary Doctorate of Education from Nipissing University. In 2009, Ms. Lankin was appointed to the Queen's Privy Council for Canada and served for five years as a member of the Security Intelligence Review Committee. In 2012, she was appointed a Member of the Order of Canada. In 2014, Ms. Lankin was appointed to the Council whose mandate was to review and identify opportunities to modernize government business enterprises, and in 2011 and 2012, she co-led a review of Ontario's social assistance system as part of the province's poverty reduction strategy. During her first term as an elected Member of Provincial Parliament, Ms. Lankin served in a variety of Cabinet roles including Chair of

Management Board, Minister of Health and Long-Term Care, and Minister of Economic Development and Trade. Ms. Lankin is currently Chair of the National NewsMedia Council, a member of the Board of Directors of the Ontario Lottery and Gaming Corporation, and a member of the Institute of Corporate Directors.

Philip S. Orsino, O.C., CPA, FCA

Mr. Philip Orsino is a consultant and corporate director and the former President and Chief Executive Officer of Jeld-Wen Inc. (2011-2014), a global integrated manufacturer of building products, and now serves as Corporate Vice Chairman. In addition to other business interests he is a Consultant to Onex Corporation for the building products industry. Mr. Orsino is a Director of The Bank of Montreal and Chair of the Audit and Conduct Review Committee. He is also a Director of The Minto Group and member of the Audit Committee. Mr. Orsino began his professional career in 1979 as a Partner with Hilborn Ellis Grant, Chartered Accountants in Toronto. From 1984 until 2005, Mr. Orsino was the President and Chief Executive Officer of Masonite International Corporation. He was formerly a Director and Chair of the Audit Committee of Clairvest Group Inc. and a Director and Board Chair of Biox Corporation. Mr. Orsino was also formerly the Chairman of the Board of Trustees of the University Health Network. He is responsible for the establishment of The Philip S. Orsino Hematology Centre and Chair in Leukemia Research, and he is an Honorary Trustee. He was appointed an Officer of the Order of Canada in 2004, was the recipient of the 2003 Canada's Outstanding CEO of the Year Award and received the University of Toronto's Distinguished Business Alumni Award for 2002. He is a Fellow of the Institute of Chartered Accountants and holds a degree from Victoria College at the University of Toronto.

Jane L. Peverett, ICD.D, FCMA

Ms. Jane Peverett is a Corporate Director and former President and Chief Executive Officer (2005-2009) of the British Columbia Transmission Corporation (BCTC). She also served as the company's Chief Financial Officer (2003 to 2005). Prior to joining BCTC, Ms. Peverett held progressively senior finance, regulatory and executive roles with Westcoast Energy Inc. between 1988 to 2003, and in 2001, was appointed President and Chief Executive Officer of Union Gas Limited, a Westcoast Energy company, becoming the first woman president of a natural gas company in Canada. Ms. Peverett is also a Director of the Canadian Imperial Bank of Commerce and Chair of its Audit Committee, and a Director of Encana Corporation where she is also Chair of the Audit Committee. She is also a Director of AEGIS Insurance Services Inc., Postmedia Network Canada Corporation, and Northwest Natural Gas Company located in Portland, Oregon. Ms. Peverett's former board service also included the B.C. Ferry Corporation, the Canadian Electricity Association, and the United Way of Lower Mainland (Greater Vancouver). Ms. Peverett earned a Bachelor of Commerce degree from McMaster University and a Master of Business Administration degree from Queen's University. She is also a Certified Management Accountant, a Fellow of the Society of Management Accountants, and holds the ICD.D designation from the Institute of Corporate Directors.

Gale Rubenstein

Ms. Gale Rubenstein is a partner of the law firm Goodmans LLP and a member of the firm's Executive Committee. She practices law primarily in the areas of commercial insolvency and restructuring with emphasis on financial institutions, both domestic and international, and on pension restructurings. Ms. Rubenstein was senior counsel to the liquidators of numerous financial institutions and has been counsel to the Superintendent of Financial Institutions (Canada) and the Superintendent of Financial Services (Ontario). She has authored numerous papers on the insolvency of insurance companies and banks, and is an update author of LexisNexis Canada's Insurance Companies Act: Legislation and Commentary. She obtained her Bachelor of Law degree from Osgoode Hall Law School (York University) and is a current Director of the Insolvency Institute of Canada; a member of Insol International; and a Director of the Osgoode Hall Alumni Association. She has been a Director of Hydro One Inc. since March 30, 2007.

Information Regarding Certain Directors and Executive Officers

None of the directors or executive officers of Hydro One Limited will beneficially own, or control, directly or indirectly, any common shares upon completion of this offering and the pre-closing transactions.

Corporate Cease Trade Orders

None of the directors or executive officers of Hydro One Limited has, within the 10 years prior to the date of this prospectus, been a director, chief executive officer or chief financial officer of any company (including Hydro

One Limited) that, while such person was acting in that capacity (or after such person ceased to act in that capacity but resulting from an event that occurred while that person was acting in such capacity) was the subject of a cease trade order, an order similar to a cease trade order, or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days.

Bankruptcies

Other than as described below, none of the directors or executive officers of Hydro One Limited is, as at the date of this prospectus, or has been within 10 years before the date of this prospectus, a director or executive officer of any company (including Hydro One Limited) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Saskatchewan Wheat Pool Inc., a predecessor to Viterra Inc., initiated a disposition of one of its businesses in 2004 through a court supervised process under the *Companies' Creditors Arrangement Act* (Canada). The securities of certain of the entities that owned and operated this business on behalf of the Saskatchewan Wheat Pool Inc. and other shareholders were cease traded by the Saskatchewan Financial Services Commission. Substantially all of the assets related to this business were sold under the court supervised process in May 2004. Mr. Schmidt served as an officer and/or director of these entities at the time.

None of the directors or executive officers of Hydro One Limited, nor any shareholder holding shares sufficient to materially affect control of Hydro One Limited, has, within the 10 years prior to the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

None of the directors or executive officers of Hydro One Limited, nor the Province, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

To the best of the Company's knowledge, there are no existing potential conflicts of interest among the Company and the directors or executive officers of the Company as a result of their outside business interests as at the date of this prospectus. Certain of the directors and executive officers serve as directors and executive officers of other public companies. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of the Company.

Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One Limited or any of its subsidiaries had any outstanding indebtedness to Hydro One Limited or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One Limited or any of its subsidiaries.

Independence of the Board of Directors

Upon closing of this offering, the Board will consist of 15 directors, 14 of whom are "independent" within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices and stock exchange requirements imposing a number or percentage of independent directors. Pursuant to Canadian securities laws, an independent director is one who is free from any direct or indirect relationship which could, in the view of the Board, be reasonably expected to interfere with a director's independent judgment, with certain specified relationships deemed to be non-independent. The Governance Agreement also requires each of the directors other than the Chief Executive Officer to be independent of the Province. See “Governance and Relationship with Principal Shareholder – Nomination of Directors – Director Qualification Standards”. The initial Chair of the Board is an independent director. Mr. Schmidt, who is a member of the Board, is not independent as he is the President and Chief Executive Officer of Hydro One Limited. Mr. Hinds was previously a director and the Chair of IESO and Ms. Jamieson was previously a director of Ontario Power Generation Inc., but because those relationships ended before August 31, 2015, they are independent of the Province within the meaning of the Governance Agreement.

The Board has separated the roles of Chair of the Board and Chief Executive Officer. The primary responsibility of the Chair is to provide leadership to the Board and to enhance Board effectiveness. The Chair, as the presiding member of the Board, also seeks to ensure that the relationships between the Board, management, the shareholder and other stakeholders are effective, efficient and further the best interests of Hydro One. The Chair also encourages input and significant participation of independent directors in the leadership of Hydro One. See “Position Descriptions”.

At each meeting of the Board, the independent directors will hold an in camera meeting (being a meeting at which members of management and those directors who are not independent directors are not in attendance) unless the Chair otherwise determines. At each meeting of each committee of the Board, the committee will also hold regular in camera meetings, unless the chair of the applicable committee determines otherwise. As well, the Audit Committee is expected to meet at least quarterly with the Chief Financial Officer, the head of the internal audit function (if other than the Chief Financial Officer) and the external auditors in separate in camera executive sessions to discuss any matters that the Audit Committee or any of these groups believes should be discussed privately. The Audit Committee shall also hold in camera sessions at least quarterly to meet without management or non-independent directors present. These sessions encourage open and candid discussion among the directors including among independent directors.

Directors’ Board Memberships in Other Reporting Issuers

Director	Reporting Issuer
Ian Bourne	Hydro One Inc. Ballard Power Systems Inc. Canadian Oil Sands Limited Wajax Corporation
Charles Brindamour	Hydro One Inc. Intact Financial Corporation
Marcello (Marc) Caira	Hydro One Inc. Restaurant Brands International Inc.
Christie Clark	Hydro One Inc. Loblaw Companies Limited Air Canada Choice Properties Real Estate Investment Trust
George Cooke	Hydro One Inc.
David Denison	Hydro One Inc. Royal Bank of Canada BCE Inc. Bell Canada Allison Transmission Holdings Inc.
Margaret (Marianne) Harris	Hydro One Inc. Sun Life Financial Inc. Sun Life Assurance Company of Canada
James Hinds	Hydro One Inc. Allbanc Split Corp.
Kathryn Jackson	Hydro One Inc. Portland General Electric
Roberta Jamieson	Hydro One Inc.
Frances Lankin	Hydro One Inc.
Philip Orsino	Hydro One Inc. Bank of Montreal
Jane Peverett	Hydro One Inc. Encana Corporation Northwest Natural Gas Company CIBC Postmedia Network Canada Corporation
Gale Rubenstein	Hydro One Inc.
Mayo Schmidt	Hydro One Inc. Agrium Inc.

Board Mandate

The mandate of the Board is to oversee the business and affairs of Hydro One. The Board seeks to discharge such responsibility by reviewing, discussing and approving Hydro One's strategic planning and organizational structure and supervising management, with a view to preserving and enhancing the business of Hydro One and its underlying value. The Board has adopted a written mandate, in the form set out under Appendix "A" to this prospectus.

Position Descriptions

The Board has adopted a written position description for the Chair of the Board, which sets out the Chair's key responsibilities, including to provide leadership to the Board to enhance the Board's effectiveness for certain accountabilities. This entails supervision of management of the Company and oversight of the relationships between the Board, management, shareholders, customers and other stakeholders. The Board has similarly adopted a written position description for the committee chairs which sets out each committee chair's key responsibilities, including of providing leadership to their respective committees. The Board has also adopted a written position description for the directors which sets out the Board's expectations of the directors for service on the Board.

The Board has adopted a written position description for the Chief Executive Officer which provides, among other matters, that the primary responsibility of the Chief Executive Officer is to manage and provide strategic direction including the development and implementation of plans, policies, strategies and budgets for the growth and profitable operation of the Company.

Orientation and Continuing Education

Following the closing of this offering, the Company will implement an orientation and continuing education program for new directors in accordance with the mandates of the Board and the Nominating, Corporate Governance, Public Policy & Regulatory Committee and the Corporate Governance Guidelines. New directors will be presented with a director manual that contains Board policies and procedures, the Company's current strategic plan, financial plan and capital plan, the most recent annual and quarterly reports and materials relating to key business issues and overview of the key organizational, financial, regulatory, and operational aspects of Hydro One.

The Board and the Nominating, Corporate Governance, Public Policy & Regulatory Committee will also be responsible for overseeing ongoing educational opportunities for the directors.

Ethical Business Conduct

The Company has a written code of conduct (the "**Code of Conduct**") that applies to all employees, directors and officers of Hydro One Limited and its subsidiaries. In addition, Hydro One requires each of its contractors, suppliers, business partners, consultants and agents to comply with the Code of Conduct, to the extent feasible, in their dealings with or on behalf of Hydro One.

The Code of Conduct sets out Hydro One's core values and establishes standards to define how employees, officers and directors of Hydro One should act. The Code of Conduct addresses, among other things, health and safety matters, conflicts of interest, discrimination and harassment, confidentiality, insider trading, environmental protection, safeguarding Hydro One's assets (including accounting and financial reporting) and relationships with outside stakeholders including investors, customers, public officials and third parties, conduct during investigations and compliance and reporting obligations. Hydro One has a Corporate Ethics Officer who is responsible for investigating actual, potential or suspected violations of the Code of Conduct, monitoring and making determinations regarding potential conflicts of interest between employees, officers and directors and Hydro One and for tracking and reporting violations to the Audit Committee in accordance with Hydro One's Whistleblower Policy. The Board monitors compliance with the Code through the Audit Committee, to whom the Corporate Ethics Officer reports. The Code of Conduct will be filed with the Canadian securities regulatory authorities on SEDAR.

Nomination of Directors

The Nominating, Corporate Governance, Public Policy & Regulatory Committee identifies qualified candidates for election to the Board and maintains an evergreen list of such potential candidates, having regard for the independence, background, employment and qualifications of possible candidates and the alignment of such candidates' competencies, skills and personal qualities with Hydro One's needs, and communicates with and makes recommendations to the Province respecting potential candidates for nomination by the Province to serve as directors of Hydro One, subject to the Governance Agreement.

The Nominating, Corporate Governance, Public Policy & Regulatory Committee also communicates with the Board and makes determinations with respect to: (i) the Committee's proposed nominees for election to the Board; and (ii) the confirmation or rejection of nominees proposed by the Province for election to the Board, in each case in accordance with the Governance Agreement.

The process for nomination of directors is set out in the Governance Agreement. See "Governance Agreement – Nomination of Directors".

Majority Voting Policy

The Company has adopted a majority voting policy as a measure to ensure that each director serving on the Board is supported in his or her role by the shareholders. Any nominee for director in an uncontested election who has more votes cast by ballot at a meeting of shareholders of the Company at which directors are to be elected (an "**Election Meeting**"), or, if no ballot is conducted, votes represented by proxies validly deposited prior to that meeting, "withheld" from his or her election (a "**Majority Withheld Vote**"), than are cast in favour of his or her election at that meeting must, immediately following that meeting, tender his or her resignation to the Board for consideration.

Under the Governance Agreement, the Province may not withhold from voting for the nominees proposed for election in accordance with the Governance Agreement in an uncontested election unless the Province withholds from voting for all the nominees other than the Chief Executive Officer and, at the Province's discretion, the Chair. Where directors have received a Majority Withheld Vote as a result of the Province withholding its vote from their election in an uncontested election and have tendered a resignation for consideration, the Board shall take whatever actions it determines are appropriate, and the directors who received a Majority Withheld Vote may participate in that determination. See "– Governance Agreement – Election and Replacement of Directors – Right to Withhold Votes".

In any other case where directors have received a Majority Withheld Vote, directors other than those who received a Majority Withheld Vote at the same Election Meeting shall consider, and within 90 days of the Election Meeting determine, whether or not to accept the resignation. The resignation shall be accepted absent exceptional circumstances and is effective when accepted by the Board. A press release disclosing the directors' determination shall be issued promptly following such determination, and if the resignation is not accepted, will include the reasons for non-acceptance. The majority voting policy does not apply to a contested election where the number of candidates for director validly nominated exceeds the number of directors to be elected at that meeting.

Board Renewal

Hydro One Limited's Board is committed to a process of renewal and succession planning for directors. In order to assist the Nominating, Corporate Governance, Public Policy & Regulatory Committee and the Board in succession planning for directors and appropriate Board renewal, the Board has adopted limits on Board service and a mandatory retirement age, which are set out in Hydro One's corporate governance guidelines (the "**Corporate Governance Guidelines**").

The Corporate Governance Guidelines provide that no non-executive director will stand for re-election at the first annual meeting of shareholders after 12 years following the date on which the director first began serving on the Board; provided that such a non-executive director may continue to stand for re-election, in special circumstances (including if necessary to facilitate orderly board renewal) and on the recommendation of the Nominating, Corporate Governance, Public Policy & Regulatory Committee, if the director continues to receive solid annual performance assessments and meets other Board policies or legal requirements for Board service. The Corporate Governance Guidelines also provide that no director shall be appointed or elected as a director after that person has reached 75 years of age unless otherwise determined by the Board.

Diversity

The Board has adopted a written board diversity policy (the "**Diversity Policy**") which formalizes the Company's commitment to diversity and its desire to maintain a Board comprising talented and dedicated directors whose skills and backgrounds reflect the diverse nature of the business environment in which it operates. Accordingly, the composition of the Board is intended to reflect a diverse mix of skills, experience, knowledge and backgrounds, including an appropriate number of women directors. The Board aspires towards a Board composition in which at least 40% of the directors of the Board are women and, initially, 40% of the directors of the Board are women (6 out of the 15). In considering the composition of the Board and the identification of qualified nominees for election as directors, the Nominating, Corporate Governance, Public Policy & Regulatory Committee has regard to, among other things, the Diversity Policy, and will assess the Diversity Policy's effectiveness in promoting a diverse Board, which includes an appropriate number of women directors, on an annual basis.

In addition to the Board's formal Diversity Policy, Hydro One strives for an inclusive corporate culture where all employees are valued and have equal access to opportunities and, in particular, Hydro One strives to ensure that its gender diversity is appropriately reflected at all levels of the organization, including executive officer positions after taking into account all relevant factors, such as merit, capability and equal treatment of employees. Of the executive officers across Hydro One, as at June 30, 2015, approximately 26%, or 6 of 23 executive officer positions, are women. Targets are not currently in place for the number of women in executive officer positions, and the Board has not yet made any determination as to whether or not targets should be set for the number of women in executive officer positions. As a new board of directors and senior leadership team were appointed in advance of this offering, the new directors and management require an appropriate amount of time to make any determination as to whether or not such targets should be set. For instance, in order to make such determination, it may be necessary to work with and assess the Company's management team, consult with the appropriate board committee(s), review the level of gender diversity below the executive officer level and succession plans for management and to consider the relevant needs and opportunities of the Company, its business and industry. It is anticipated that the new board of directors and management will make such determination in due course.

Committees of the Board

The Board has established four committees: (i) the Audit Committee; (ii) the Nominating, Corporate Governance, Public Policy & Regulatory Committee; (iii) the Health, Safety, Environment and First Nations & Métis Committee; and (iv) the Human Resources Committee. All members of these committees will be persons determined by the Board to be "independent" directors within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices, stock exchange rules applicable to service on the relevant committee (if any) and the Governance Agreement. A majority of the members of each committee will be residents of Canada.

Audit Committee

The Audit Committee will consist of at least three directors, all of whom are persons determined by Hydro One to be both "independent" (within the meaning of all Canadian securities laws and stock exchange requirements and the Governance Agreement) and "financially literate" (within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including National Instrument 52-110 – *Audit Committees*). At least one member of the Audit Committee will qualify as an "audit committee financial expert" as defined by the applicable rules of the United States Securities and Exchange Commission. The Audit Committee will initially comprise Philip Orsino (Chair), Charles Brindamour, George Cooke, James Hinds, Roberta Jamieson and Frances Lankin. Each of the Audit Committee members has an understanding of the accounting principles used to prepare Hydro One's financial statements and varied experience as to the general application of such accounting principles, as well as an understanding of the internal controls and procedures necessary for financial reporting. For additional details regarding the relevant education and experience of each member of the Audit Committee, see "Directors and Management of the Company – Biographical Information".

The Board has adopted a written charter for the Audit Committee, in the form set out under Appendix "B" to this prospectus, which sets out the Audit Committee's responsibilities. The Audit Committee's responsibilities will include overseeing: (i) the independence, qualification and appointment of external auditors; (ii) the integrity of Hydro One's financial statements and financial reporting process, including the audit process and Hydro One's internal control over financial reporting, disclosure controls and procedures and compliance with other related legal and regulatory requirements; (iii) the performance of Hydro One's finance function, internal auditors and external auditors; and (iv) the auditing, accounting and financial reporting process. The Audit Committee is also responsible for reviewing with the external auditors and management and recommending to the Board for approval Hydro One's annual and quarterly results.

External Auditor Service Fees

In 2013 and 2014, Hydro One Inc. was billed the following fees by its external auditor, KPMG LLP:

	Fiscal 2014		Fiscal 2013	
Type of Fees	**Fees**	**% of Total**	**Fees**	**% of Total**
Audit Fees	$735,776	84.1%	$ 807,176	78.1%
Audit-Related Fees	$139,083(1)	15.9%	$ 204,083(2)	19.8%
Tax Fees	—	—	—	—
All Other Fees(3)	—	—	$ 21,714	2.1%
Total	$874,859	100%	$1,032,973	100%

Notes:

(1) The nature of services rendered were: audit of the Hydro One Inc. Pension Plan, audit of the Hydro One Inc. Employees' and Pensioners' Charity Trust, audit of the Apprenticeship Enhancement Fund Audit, French translations, and executive expense reviews.

(2) The nature of services rendered were: audit of the Hydro One Inc. Pension Plan, audit of the Hydro One Inc. Employees' and Pensioners' Charity Trust, audit of the Apprenticeship Enhancement Fund Audit, French translations, incremental procedures performed over implementation of the Customer Information System, and executive expense reviews.

(3) These fees were related to a review of the sufficiency of Hydro One Inc.'s documentation of the controls and procedures identified as addressing certain additional laws and regulations as a result of becoming an SEC registrant.

Nominating, Corporate Governance, Public Policy & Regulatory Committee

The Nominating, Corporate Governance, Public Policy & Regulatory Committee will consist of at least three directors, all of whom must be "independent" (within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices, stock exchange rules applicable to service on this committee and the Governance Agreement). These individuals will be charged with reviewing, overseeing and evaluating the corporate governance and nominating policies of Hydro One. The Nominating, Corporate Governance, Public Policy & Regulatory Committee will initially comprise Jane Peverett (Chair), Ian Bourne, Marc Caira, Christie Clark, Kathryn Jackson, Frances Lankin and Philip Orsino.

The Board has adopted a written charter for the Nominating, Corporate Governance, Public Policy & Regulatory Committee setting out its responsibilities for: (i) managing and overseeing the process for nominating new directors to the Board in accordance with the Governance Agreement; (ii) making recommendations respecting the Board's approach to corporate governance; (iii) planning for Chair succession; (iv) overseeing director orientation and continuing education; (v) overseeing the Board and director performance evaluation process; (vi) making recommendations with respect to director compensation and protection; (vii) overseeing Hydro One's relationship with shareholders, communities, stakeholders, electricity regulators, customers, and the Province; and (viii) the Company's approach to corporate social responsibility, including its sponsorship and donation program.

The Nominating, Corporate Governance, Public Policy & Regulatory Committee is also responsible for the identification and nomination of qualified nominees for election to the Board and for making recommendations regarding committee assignments, director compensation, and corporate governance policy for the committees and the Board as a whole. See "– Nomination of Directors". The Nominating, Corporate Governance, Public Policy & Regulatory Committee is also responsible for: (i) assessing, on an annual basis, the effectiveness of the Board as a whole, each committee of the Board, the Chair, each committee chair and each individual director (having regard to the mandate of the Board and the mandate of the relevant committee, as the case may be) and making recommendations to the Board; (ii) reviewing the annual Board and committee performance evaluation process itself; and (iii) reporting to the Chair the results of both the annual assessment and performance evaluation process.

The Board believes that the members of the Nominating, Corporate Governance, Public Policy & Regulatory Committee individually and collectively possess the requisite knowledge, skill and experience in governance and compensation matters, including executive compensation matters and general business leadership, to fulfill the committee's mandate.

Health, Safety, Environment and First Nations & Métis Committee

The Health, Safety, Environment and First Nations & Métis Committee will consist of at least three directors, all of whom must be "independent" (within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices, stock exchange rules applicable to service on this committee and the Governance Agreement). The Health, Safety, Environment and First Nations & Métis Committee will initially comprise Marianne (Margaret) Harris (Chair), George Cooke, James Hinds, Kathryn Jackson, Roberta Jamieson and Gale Rubenstein. The Health, Safety, Environment and First Nations & Métis Committee is responsible for assisting the Board in discharging its oversight responsibilities relating to: (i) effective occupational health and safety and environmental policies and practices at Hydro One; and (ii) Hydro One's relationship with First Nations and Métis communities.

Human Resources Committee

The Human Resources Committee will consist of at least three directors, all of whom must be "independent" directors (within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices, stock exchange rules applicable to service on this committee and the Governance Agreement). The Human Resources Committee will initially comprise Ian Bourne (Chair), Charles Brindamour, Marc Caira, Christie Clark, Marianne Harris, Gale Rubenstein and Jane Peverett. All of the committee members have gained experience in human resources and compensation by serving as an executive officer (or equivalent) of a major organization and/or prior service on the compensation committee of a stock exchange listed company. For additional disclosure regarding the skills and experience that enable the members of the Human Resources Committee to make decisions on the suitability of the Company's compensation policies and practices, as well as the direct experience that is relevant to each committee member's responsibilities in executive compensation, see "Directors and Management of the Company – Biographical Information".

The Human Resources Committee is responsible for assisting the Board in fulfilling its oversight responsibilities relating to the compensation, attraction and retention of key senior management. The Human Resources Committee is responsible for assisting the Board in discharging its oversight responsibilities relating to: (i) reviewing and recommending to the Board compensation payable, including appropriate performance incentives, to the Chief Executive Officer and certain designated employees; (ii) reviewing the administration of employee compensation and incentive plans and programs; and (iii) reviewing executive and director compensation disclosure to be made in the Company's management information circular prepared in connection with the Company's annual meeting of shareholders and other public disclosure as appropriate. The Human Resource Committee's responsibilities also include reviewing the compensation policies of the Company, ensuring that the Company's compensation programs are aligned with the Company's strategic plans and risk profile, and reviewing the Company's succession planning and talent management processes.

EXECUTIVE COMPENSATION

Since the appointment of a new independent Board, Hydro One has been focused on recruitment of experienced executive leadership to lead the Company through this offering, and formulate a strategy for future growth. It has also recognized a need to implement a compensation system for incumbent management employees that is performance-based and reflects compensation systems appropriate for similarly-situated public companies.

Hydro One's compensation strategy is to attract, motivate and retain highly qualified executives with the skills to sustain and develop safe, reliable and affordable services for the Company's customers, while also aligning the interests of executives with the Company's shareholders. The compensation philosophy for Hydro One will reflect a stronger alignment between pay and performance, especially over the longer term, to provide a foundation to drive growth, deliver strong financial performance and create and sustain shareholder value. Leading compensation practices have been adopted for new management hires, including:

- a peer group for benchmarking Chief Executive Officer and Chief Financial Officer compensation prepared, with the assistance of the independent compensation advisor to the Human Resources Committee of the Board, following a careful review of power generation, transmission and distribution industry peers and comparably-sized companies with a similar business model within the broader energy industry;
- a substantially larger portion of executive compensation being variable and tied to performance over multiple years;

- provisions for the clawback of compensation in the event the executive is overpaid as a result of an error resulting in a restatement of reported financial results or due to inaccurate financial data;
- no incremental benefits if there is a change in control unless there has been a termination of employment without cause or for good reason; and
- significant share ownership requirements (which extend past retirement).

The Board also decided to introduce a new, lower cost defined contribution pension plan for externally hired executives to be implemented in 2016 in place of Hydro One's Defined Benefit Pension Plan.

Although some new executives have been hired on the basis of Hydro One's new approach to executive compensation, adjustments to the Company's structure and compensation system have not yet been implemented as the complexity and change related to these new structures is significant and the Board will introduce these changes for incumbent management employees during 2016. As such, transitional arrangements are in place for 2015 and in some cases into 2016, pending the determination and implementation of detailed initiatives consistent with the Company's new approach. Therefore, longer-serving members of the senior leadership team will continue to receive compensation in line with the Company's historic approach, pending their transition to new arrangements.

Compensation Governance

Human Resources Committee

The Human Resources Committee is responsible for assisting the Board in fulfilling its oversight responsibilities relating to the compensation, attraction and retention of key senior management, and it will consist of at least three directors, all of whom must be "independent" directors (within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices, stock exchange rules applicable to service on this committee and the Governance Agreement). See "Directors and Management of the Company—Committees of the Board – Human Resources Committee" for additional information regarding the Human Resources Committee, its mandate, composition and the relevant experience of its members. All of the committee members have gained experience in human resources and compensation by serving as an executive officer (or equivalent) of a major organization and/or prior service on the compensation committee of a stock exchange listed company. For additional disclosure regarding the skills and experience that enable the members of the Human Resources Committee to make decisions on the suitability of the Company's compensation policies and practices, see "Directors and Management of the Company".

Compensation Consultant

In 2014, Hugessen Consulting Inc. ("**Hugessen**"), an independent consulting firm that provides advice to boards and compensation committees on executive compensation, was retained to provide advice to the former corporate governance and human resources committee of Hydro One Inc. with respect to the approval of Hydro One Inc.'s performance scorecard for that year and the assessment of the year end scorecard results. In 2015, Hugessen was engaged to assist in the development of the compensation structure for the new Board, to review and make recommendations with respect to the development of a new compensation peer group in anticipation of the leadership changes and this offering, conduct comparative analyses of compensation arrangements, provide advice on the new compensation structures and arrangements for the new Chief Executive Officer and Chief Financial Officer, and more broadly provide advice on the development of the new compensation framework to be considered for introduction in 2016.

Hugessen's fees incurred to date during 2015 and during 2014 regarding services provided to the Company and Hydro One Inc. are as follows:

Fiscal Year Ended	Executive Compensation-Related Fees	All Other Fees
December 31, 2015(1)	$183,222	$21,639(2)
December 31, 2014	$ 33,845	$ 0

Notes:

(1) Fees incurred up until July 31, 2015, inclusive of taxes and administration fees.

(2) Fees incurred for advice regarding director compensation.

Compensation Discussion and Analysis

As noted above, since the appointment of the new Board, Hydro One's approach to executive compensation has been focussed on recruitment and retention of experienced executive leadership. Initially, with the help of its independent compensation advisor, the Human Resources Committee focussed on developing a market competitive approach to compensation targeting total direct compensation for executives consistent with similarly-positioned executives at comparable publicly-traded companies. Thus far, the Board of Hydro One has successfully recruited Mayo Schmidt as President and Chief Executive Officer and Michael Vels as Chief Financial Officer.

The following section discusses the compensation structure, programs and significant elements of compensation for Mayo Schmidt and Michael Vels and the Company's approach to executive compensation going forward. This section also references compensation arrangements for the three next most highly compensated executive officers who are continuing to provide services to the Company and its subsidiaries, being: Carmine Marcello, Special Advisor to the Chief Executive Officer and to Chair of the Board; Sandy Struthers, Chief Operating Officer; and Robert Cultraro, Senior Vice President and Chief Investment and Pension Officer. Collectively, these five executive officers are the Company's Named Executive Officers ("**NEOs**").

Approach to Compensation

Hydro One's compensation strategy is to attract, motivate and retain highly qualified executives with the skills to sustain and develop safe, reliable, and affordable services for the Company's customers while also aligning the interests of the executives with the Company's shareholders. The Company's executive compensation framework is based on the following objectives and principles:

- *Support Business Strategy* – support the achievement of Hydro One's short term and long term corporate objectives, future work and infrastructure program, and be consistent with Hydro One's vision, mission and core values;
- *Market Competitive* – facilitate attraction of new talent and foster retention of existing employees;
- *Performance Focus* – reflect a strong pay-for-performance philosophy by delivering a substantial proportion of total compensation using variable pay primarily tied to the Company's performance with some element of individual performance, and the majority of variable compensation tied to long term performance; and
- *Shareholder Alignment* – focus on specific performance objectives that contribute to the enhancement of shareholder value in the long term.

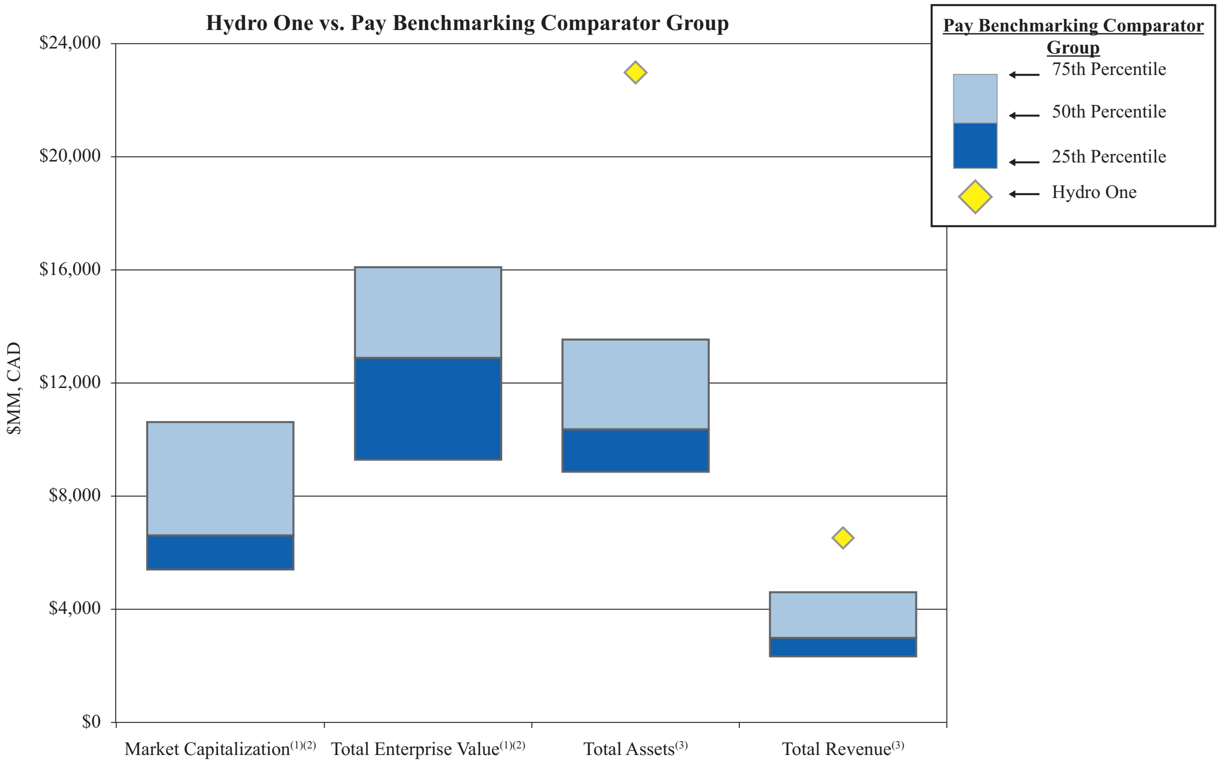
Benchmarking and Pay Positioning for New Chief Executive Officer and New Chief Financial Officer

The Company's compensation philosophy is to provide total compensation opportunities that are competitive in the context of relevant peer groups for various management levels. For purposes of recruiting Hydro One's new Chief Executive Officer and Chief Financial Officer, the Company identified a primary reference group consisting of the four largest utilities listed on the TSX plus four other TSX listed companies within the broader energy industry of comparable size and scope of operations to Hydro One. These eight companies are listed in the following table:

Compensation Peer Group

Fortis Inc.	ATCO Inc.
Emera Incorporated	TransAlta Corp.
Pembina Pipeline Corporation	Keyera Corp.
AltaGas Ltd.	Inter Pipeline Ltd.

In selecting this group of peers, the Company considered scoping criteria that are reflective of the size, scale and complexity of the businesses, including revenue, assets, market capitalization and enterprise value. Companies were selected generally based on a range of approximately 0.5x to 2.0x Hydro One's positioning on specific criteria. Following the closing of this offering, Hydro One is expected to be relatively large by all such metrics, as summarized in the following chart (attributable to the fact that there are few Canadian publicly traded similar businesses).



Notes:

(1) As at May 1, 2015. "Market Capitalization" is calculated based on the number of common voting shares multiplied by the closing share price and "Total Enterprise Value" is calculated based on Market Capitalization, plus net debt.

(2) It is expected that the "Market Capitalization" and "Total Enterprise Value" of Hydro One following completion of this offering will be in the upper quartile of its comparator group.

(3) Last twelve months' total assets and total revenues are calculated as at June 30, 2015.

(4) Information in this chart was prepared by Hugessen using data from S&P Capital IQ.

For additional context, the Human Resources Committee also considered a subgroup of members of the S&P/TSX 60 index companies consisting of the 30 members of such index with the lowest market capitalization, as Hydro One was expected to be of comparable size to such companies (the "**Smaller Subgroup S&P/TSX60**"). These 30 members are listed in the following table:

Smaller Subgroup S&P/TSX60 Companies	
Agnico Eagle Mines Limited	Gildan Activewear Inc.
ARC Resources Ltd.	Kinross Gold Corporation
BlackBerry Limited	Metro Inc.
Bombardier Inc.	National Bank of Canada
Cameco Corporation	Pembina Pipeline Corporation
Canadian Oil Sands Limited	Penn West Petroleum Ltd.
Canadian Tire Corp. Ltd.	Power Corporation of Canada
Cenovus Energy Inc.	Saputo Inc.
CGI Group, Inc.	Shaw Communications, Inc.
Eldorado Gold Corporation	Silver Wheaton Corp.
Encana Corporation	SNC-Lavalin Group Inc.
Enerplus Corporation	Talisman Energy Inc.
First Quantum Minerals Ltd.	Teck Resources Limited
Fortis Inc.	TransAlta Corp.
George Weston Limited	Yamana Gold, Inc.

The target total direct pay for 2016 for the new Chief Executive Officer and Chief Financial Officer was set by the new Board, taking a range of factors into account, including the benchmarking results, and the fact that arrangements were agreed upon with each candidate in the context of a thorough executive search process with specific requirements for each role requiring a high level of skill and proven experience with large, complex publicly traded enterprises. Target total direct pay includes base salary, target short term incentive and target long term incentive. The target total direct pay for the Chief Executive Officer for 2016 is positioned close to the average of the four other large utilities (although Hydro One is the largest of them all based on the various metrics noted above), and is in the bottom quartile of the Smaller Subgroup S&P/TSX60. Similarly, the target total direct pay for the Chief Financial Officer is in the bottom quartile of the Smaller Subgroup S&P/TSX60. The target total direct pay for 2016 for each of these two executive officers is summarized in the table below.

	Base Salary	Target Short Term Incentive	Target Long Term Incentive	Target Total Direct Compensation
Chief Executive Officer	$850,000	$765,000	$2,385,000	$4,000,000
Chief Financial Officer	$500,000	$300,000	$ 700,000	$1,500,000

Components of Compensation

Overall compensation will include base salary, annual short term incentives, and long term incentives, as well as benefits. Realized compensation will be dependent on achieved Company and individual performance. The Human Resources Committee has not yet made any determination as to the types of awards to be granted and the performance objectives to be used in respect of both the Long Term Incentive Plan (described below under "– Long Term Incentive Plan") and the Short Term Incentive Plan (described below under "– Short Term Incentive Plan"). The Company expects that these determinations will be made in 2016.

The table below describes the proposed components of compensation for the Company's Chief Executive Officer and Chief Financial Officer for 2016. As described under "– Transitional Arrangements" below, for 2015 the Chief Executive Officer and Chief Financial Officer are entitled to receive a cash payment equal to the sum of their annualized target short term incentive and annualized long term incentive pro rated for the length of their service in 2015. Compensation for 2015 for the other NEOs, by contrast, does not include any long term incentive component and a substantially higher proportion of compensation is fixed.

	Component	Objectives
Fixed	Base Salary	• Attract and retain talent, as well as provide a predictable and steady income. • Annual base salaries are based on job function, individual performance and experience, market competitiveness, and internal equity considerations.
	Pension and Benefits	• NEOs participate in benefit programs (including registered pension plans and supplementary pension plans) and flexible benefits plans available to all employees. • Provide market-competitive benefits to attract and retain talent.
Variable	Short Term Incentive	• Primarily motivate and reward achievement of annual corporate business and financial performance objectives. In addition, a portion of annual incentives are tied to an element of individual performance. • Incentive targets are based on market competitiveness, measured with reference to business and industry performance benchmarks set by the Board.
	Long Term Incentive	• Motivate and align executives with long term strategy and shareholders' interests.

Fixed Compensation

Base Salary

Base salary is provided as a fixed source of compensation for the NEOs in connection with their day-to-day ongoing performance. Initial base salary levels for the NEOs have been determined after review of the competitive compensation practices of peer groups giving consideration to the overall level of pay competitiveness and the performance of the NEO. Adjustments to base salaries will be determined annually and may be increased based on the executive's success in meeting or exceeding individual objectives and an assessment of the competitiveness of current compensation. Additionally, base salaries can be adjusted as warranted throughout the year to reflect promotions or other changes in the scope of breadth of an executive's role or responsibilities, as well as to maintain market competitiveness.

Pension and Benefits

The Board has decided to introduce a new, lower cost defined contribution pension plan. The Chief Executive Officer and Chief Financial Officer are entitled to participate in such defined contribution pension plan and supplementary executive retirement plan when they are established in 2016. NEOs other than the Chief Executive Officer and Chief Financial Officer currently participate in Hydro One's Defined Benefit Pension Plan. The Company has closed participation in Hydro One's Defined Benefit Pension Plan to externally hired Company management entrants. See "– Existing Pension Arrangements".

The NEOs participate in benefit programs and in a flexible benefits plan, which is also available to all other management employees. The flexible benefits plan provides various benefits, including life insurance, vacation and health care benefits. Hydro One provides to each executive and management employee certain core benefits, which include basic life insurance, accident insurance, extended health benefits, dental, sick leave and long term disability, pension and basic vacation. However, benefits are not intended to be a significant element of compensation for the NEOs.

Variable Compensation

Short Term Incentives

The Company will adopt for 2016 a short term incentive plan ("**Short Term Incentive Plan**") designed to motivate NEOs to achieve the Company's short term corporate goals, and rewards individual and overall Hydro One performance. See "– Short Term Incentive Plan".

Incentives will have a high degree of focus on key drivers of shorter term success and will be linked to the annual business planning cycle. Bonus targets will vary by position and will be reviewed periodically to ensure market competitiveness. Performance is intended to be measured based on a combination of both Company and individual performance measures.

Long Term Incentives

The Company's Long Term Incentive Plan, described below under "– Long Term Incentive Plan", allows the Board to grant long term incentives to the NEOs, senior executive team, and other management executives consistent with the provisions of the plan. Long term incentives are designed to align executive long term interests with those of the Company's shareholders. The mix of long term incentive vehicles has not been determined and, accordingly, the Long Term Incentive Plan provides flexibility to award a range of vehicles, including restricted share units ("**RSUs**"), performance share units ("**PSUs**"), stock options ("**Options**"), share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance, but for the executive officers is intended to include some combination of:

- Grants of Options to be used in a targeted way, to focus the NEOs and senior executive team on activities aimed at maximizing long term shareholder value;
- Performance-vesting PSUs to be used to encourage the NEOs, senior executive team and other executives to achieve specific corporate objectives; and
- Time-vesting RSUs to be used to attract and retain executives and other management employees.

Transitional Arrangements

Hydro One has for several years applied compensation practices that are consistent with the *Broader Public Sector Accountability Act, 2010* (Ontario) (the "**BPSAA**"). The BPSAA imposes compensation restraint measures on the compensation plans of defined designated executives from March 31, 2012 until such time as the Province proclaims that the restraint measures have expired, which cannot be before the fiscal year in which the Province no longer has a deficit. Effective from June 4, 2015, the BPSAA is no longer applicable to Hydro One. In addition, as of June 4, 2015, the *Broader Public Sector Executive Compensation Act, 2014* (Ontario) (the "**BPSECA**"), legislation which would otherwise have applied to Hydro One in the place of the BPSAA, also does not apply to Hydro One. Hydro One's Chief Executive Officer and Chief Financial Officer were retained after the BPSAA ceased to apply to the Company and their compensation arrangements reflect Hydro One's new approach to executive compensation.

While the legislative requirements of the BPSAA and BPSECA no longer apply to the Company, the compensation of the other NEOs continues to be governed by Hydro One's prior arrangements and practices. Compensation for 2015 for the other NEOs also reflects consideration of a separate compensation peer group consisting of 30 Canadian-based entities (15 public and 15 private) selected based on criteria such as organizations with revenue of at least $1 billion, reporting in the heavy industrial sector, with a large unionized workforce, a pay-for-performance culture, and many engineering/technologist job positions.

These 30 companies are listed in the following table:

Public Sector	Private Sector
Atomic Energy of Canada Limited	ArcelorMittal Canada
Business Development Bank of Canada	Amec Americas Limited
Canada Mortgage and Housing Corporation	Barrick Gold Corporation
Canadian Standards Association/CSA Group	Bombardier Transportation Canada Inc.
Enersource Hydro Mississauga Inc.	Bruce Power LP
Farm Credit Canada	Canadian National Railway Company
Government of Ontario	Fortis Inc.
Hydro Ottawa Limited	FortisBC Energy Inc.
NB Power Holding Corporation	Glencore
Ontario Power Authority	Goldcorp Inc.
Ontario Power Generation	Newfoundland Power Inc.
Royal Canadian Mint	Siemens Canada Limited
SaskEnergy Incorporated	Suncor Energy Inc.
Sask Tel	Ultramar Ltée
Toronto Hydro	Vale Canada
Total: 15	**Total: 15**

For 2015, the NEOs other than the Chief Executive Officer and Chief Financial Officer have a maximum allowable short term incentive fixed at a percentage of their salary. Also, such NEOs are not entitled to long term incentive compensation as for 2015 Hydro One did not have a long term incentive compensation component in its compensation program.

Certain transitional arrangements are in place in respect of short term incentives and long term incentives for the Chief Executive Officer and the Chief Financial Officer for 2015, as they were both hired in the second half of the current year. Pursuant to the terms of their employment arrangements, the Chief Executive Officer and the Chief Financial Officer are entitled to receive a cash payment equal to their target short term incentive payment pro rated for the length of their service in 2015. No long term incentive payments will be awarded for 2015. However, under their employment agreements, the Chief Executive Officer and the Chief Financial Officer are each entitled to receive a cash payment in lieu of a long term incentive award equal to his annualized target long term incentive award pro rated for his length of service in 2015. Cash received in lieu of a long term incentive award for 2015 will be paid in early 2016. Each of the Chief Executive Officer and the Chief Financial Officer will be required to take the after-tax amount received from such payment in lieu of a long term incentive award to purchase shares on the open market in order to accelerate achievement of share ownership guidelines.

For NEOs other than the Chief Executive Officer and the Chief Financial Officer, no target compensation levels were established for 2015. The Company's intention is that in time all of its executive officers will be compensated in a manner generally consistent with the philosophy and direction reflected in the Company's arrangements with its Chief Executive Officer and Chief Financial Officer. For 2016, it is anticipated that the Board will set business and industry performance benchmarks for incentive awards, the Company will establish target awards for all executive officers measured with reference to such benchmarks and the Board will grant awards to executive officers under the Long Term Incentive Plan.

Compensation Mix

For the Chief Executive Officer and Chief Financial Officer, target total direct compensation will consist of the elements noted below. Determinations for the other NEOs have not yet been made.

	Chief Executive Officer		Chief Financial Officer	
	Target	Percentage total direct compensation	Target	Percentage of total direct compensation
Base Salary	$850,000	21%	$500,000	33%
Short Term Incentive(1)	90% of base salary	19%	60% of base salary	20%
Long Term Incentive(2)	280% of base salary	60%	140% of base salary	47%

Notes:

(1) Each of the Chief Executive Officer and the Chief Financial Officer may elect to receive up to 100% of his annual incentive bonus as deferred share units.

(2) In addition to its general discretion with respect to long term incentive awards, the Board has the discretion to vary the actual award level for the long term incentive from 75% to 125% of the target award level based on a range of factors, including individual executive performance and company performance.

Compared to existing compensation arrangements in place for the other NEOs, the compensation mix for the Chief Executive Officer and Chief Financial Officer reflects relatively lower salaries and short term incentives, but a relatively greater proportion of variable "at risk" compensation, in each case as a percentage of total direct compensation awarded.

Compensation Risk Management

Hydro One intends to structure its compensation program to employ the procedures designed to avoid any excessive risks which may result from the implementation of its executive compensation policy and practices. Such procedures are intended to include:

Pay Mix	The variable component of Hydro One's compensation program (which includes both short term and long term incentives) represents a sufficient percentage of "at-risk" compensation to motivate executives and other employees of the Company to focus on both short term and long term results and performance criteria. Elements of compensation, together, ensure a balance in the mix of fixed and variable compensation, short term and long term incentives, cash versus equity, and performance-based versus time-based awards.
Capped Payouts	The maximum amount an executive can receive under the Short Term Incentive Plan is intended to be capped at not more than 200% of the target level.
Effective Design of Long Term Incentive Mix	Long term incentives will vest over time, either in instalments or via cliff-vesting. A balance of time-vesting and performance-vesting long term incentives and varied performance measures mitigate against taking short term risks and aligns management with longer-term shareholder interests.

Hydro One intends to implement a compensation program which provides an appropriate balance of risk and reward consistent with the risk profile of the Company. Hydro One seeks to ensure that its compensation practices do not encourage excessive risk-taking behaviour by the executive team.

All of Hydro One's directors, officers (including the NEOs) and employees will be subject to the Company's insider trading policy, which will, among other things, prohibit trading in the securities of the Company while in possession of material undisclosed information concerning the Company. Further, such individuals will be prohibited from undertaking certain types of trades in securities of the Company which can raise particular concerns about potential breaches of applicable securities law or that the interests of the persons making the trade are not aligned with those of the Company.

All grants under the Long Term Incentive Plan will be subject to clawback by the Company in certain circumstances. See "– Long Term Incentive Plan".

Summary Compensation Table

The following table summarizes the compensation the Company intends to pay its NEOs for the year ending December 31, 2015, Hydro One Limited's first fiscal year as a public company.

					Non-equity incentive plan compensation ($)				
Name and Principal Position	**Year**	**Salary[1] ($)**	**Share-based awards ($)**	**Option-based awards ($)**	**Annual incentive plans ($)**	**Long-term incentive plans ($)**	**Pension value ($)**	**All other compensation[2][3] ($)**	**Total compensation ($)**
Mayo Schmidt *President and Chief Executive Officer*	2015	281,154	Nil	Nil	253,038[4]	Nil	37,956[5]	787,231[4]	1,359,379
Michael Vels *Chief Financial Officer*	2015	253,846	Nil	Nil	152,308[6]	Nil	34,269[5]	355,385[6]	795,808
Carmine Marcello *Special Advisor to the Chief Executive Officer and Chair of the Board*	2015	525,000	Nil	Nil	205,542[7]	Nil	(619,000)[8]	407,500[9]	519,042
Sandy Struthers *Chief Operating Officer*	2015	435,000	Nil	Nil	161,333[7]	Nil	(2,000)[8]	Nil	594,333
Robert Cultraro *SVP, Chief Investment and Pension Officer*	2015	250,000	Nil	Nil	116,667[7]	Nil	54,000[8]	Nil	420,667

Notes:

(1) Base salaries presented are amounts expected to be paid for fiscal 2015 (pro rated in the case of the Chief Executive Officer and the Chief Financial Officer to reflect their respective start dates).

(2) As a percentage of annualized base salary, represents grant date target fair value (and financial statement amounts) of awards under the Long Term Incentive Plan at 280% for Mr. Schmidt and 140% for Mr. Vels. See "– Long Term Incentive Plan".

(3) None of the NEOs are entitled to perquisites or other personal benefits which, in the aggregate, are worth over $50,000 or over 10% of their annualized base salary for 2015.

(4) For 2015 only, in place of his long term incentive, Mr. Schmidt will receive a cash payment in respect of his target long term incentive award of 280% of base salary and a payment in respect of his target short term incentive award of 90% of base salary, in each case pro-rated from his September 3, 2015 start date.

(5) The 2015 compensatory value is equal to the expected contribution in respect of expected 2015 earnings expected to be remitted to a defined contribution supplementary executive retirement plan established following the closing of this offering. The terms of the defined contribution supplementary executive retirement plan are not currently known. The Company anticipates that the 2015 contribution will be credited to the defined contribution supplementary executive retirement plan during 2016 and it is not expected that this contribution will be increased with interest. Accordingly, no interest has been included in the non-compensatory element of the pension table.

(6) For 2015 only, in place of his long term incentive, Mr. Vels will receive a cash payment in respect of his target long term incentive award of 140% of base salary and a payment in respect of his target short term incentive award of 60% of base salary, in each case pro-rated from his July 1, 2015 start date.

(7) Represents the three-year average of the actual percentage of base salary paid on short term incentive, multiplied by the base salary for the respective NEO for 2015. Short term incentive payable to incumbent management executives is capped as a percentage of base salary at 65% for Mr. Marcello, 60% for Mr. Struthers and 60% for Mr. Cultraro. Incumbent management executives have historically received short term incentive awards at below the capped amounts.

(8) The pension value will include a combination of annual current service cost as well as the past service impact of other compensating amounts. The pension plan provides a benefit, in respect of all years of service, which is based on each plan member's highest average earnings at the time of his or her termination or retirement. The value of the increase or decrease in the present value of the defined benefit obligation is affected by differences between actual compensation for the year and the earnings increase assumptions for the year, assumed at the end of the prior year. When the actual earnings increase is not in line with the assumed level, it impacts the total defined benefit obligation in respect of past service. If the expected highest average earnings based on the most recent information is lower than the highest average earnings based on the prior year estimate, it results in a decrease in the defined benefit obligation. For certain NEOs, this has resulted in a negative pension value. See "– Existing Pension Arrangements".

(9) Mr. Marcello will receive payment on December 31, 2015 for an amount equivalent to 6-months of his base salary plus 50% of his short term incentive payment for 2014 with respect to his provision of continuity services to the Chief Executive Officer and to the Chair of the Board, provided he continues to devote his full time and attention to his responsibilities at Hydro One to such date.

Long Term Incentive Plan ("Long Term Incentive Plan")

The Board has adopted the Long Term Incentive Plan effective August 31, 2015 and all equity-based awards to be settled in newly-issued shares will be granted under the Long Term Incentive Plan. In the future, the Company may consider adopting other long term incentive plans where awards will be settled in cash or market-purchased shares. The following summary describes the material terms of the Long Term Incentive Plan. This summary of the Long Term Incentive Plan is not a complete description of all provisions of the Long Term Incentive Plan and is qualified in its entirety by reference to the Long Term Incentive Plan.

Administration

The Long Term Incentive Plan is administered by the Human Resources Committee. The Human Resources Committee has the authority to, among other things, determine eligibility for awards to be granted, determine, modify or waive the type or types of, form of settlement (whether in cash, common shares or other property) of, and terms and conditions of awards, to accelerate the vesting or exercisability of awards, to adopt rules, guidelines and practices governing the operation of the Long Term Incentive Plan as the Human Resources Committee deems advisable, to interpret the terms and provisions of the Long Term Incentive Plan and any award agreement, and to otherwise do all things necessary or appropriate to carry out the purposes of the Long Term Incentive Plan. The Human Resources Committee's decisions with respect to the Long Term Incentive Plan and any award under the Long Term Incentive Plan are binding upon all persons.

Eligibility

Hydro One's key employees who, in the opinion of the Human Resources Committee, have the capacity to contribute to the Company's and the Company's affiliates' success are eligible to participate in the Long Term Incentive Plan. Non-employee directors on the Board are not entitled to receive awards under the Plan.

Authorized Shares

Subject to adjustment, as described below, the maximum number of common shares that are available for issuance under the Long Term Incentive Plan is 11,900,000 common shares, representing 2% of the common shares issued and outstanding on the completion of this offering. The maximum number of common shares which may be issued as RSUs, PSUs or deferred share units ("**DSUs**") is 4,760,000 common shares, representing 0.8% of the common shares issued and outstanding on the completion of this offering.

Common shares subject to an award that, for any reason expires without having been exercised, is cancelled, forfeited or terminated or otherwise is settled without the issuance of shares, will again be available for grant under the Long Term Incentive Plan. The grant of a tandem award of an Option and a share appreciation right ("**SAR**") will reduce the number of common shares available for awards under the Long Term Incentive Plan by the number of common shares subject to the related Option (and not as to both awards). To the extent consistent with applicable legal requirements (including applicable stock exchange requirements), common shares issued under awards of an acquired company that are converted, replaced or adjusted in connection with the acquisition will not reduce the number of shares available for awards under the Long Term Incentive Plan.

Types of Awards

The Long Term Incentive Plan provides for awards of Options, SARs, RSUs, PSUs, restricted shares, DSUs, and other share-based awards. Eligibility for Options is limited to the Company's employees. Dividend equivalents may also be provided in connection with an award under the Long Term Incentive Plan.

- *Options and SARs*. The exercise price of a stock option, and the base price against which a SAR is to be measured, may not be less than the fair market value of the common shares on the date of grant. The Human Resources Committee will determine the time or times at which Options or SARs become exercisable and the terms upon which such awards remain exercisable. The maximum term of Options and SARs is ten years. However, if an award is scheduled to expire during, or within five business days after, a period imposed by Hydro One Limited restricting employees from engaging in any open-market sales of the common shares, then the award shall expire ten business days after such restricted trading period is lifted by Hydro One Limited.

  A SAR that is granted in tandem with a stock option will become vested and exercisable on the same date or dates as the related stock option and may only be exercised upon the surrender of the right to exercise the related option for an equivalent number of common shares.

- *RSUs*. An RSU award is an award that entitles the participant to receive common shares in the future. The delivery of common shares under an RSU award may be subject to the satisfaction of performance conditions or other vesting conditions.
- *PSUs.* A performance share unit is an award that entitles the participant to receive common shares in the future, but the vesting, settlement or exercisability of which is subject to specified performance criteria.
- *Restricted shares*. A restricted share award is an award of common shares subject to forfeiture restrictions.
- *DSUs*. A DSU is an award that entitles the participant to receive common shares following termination of employment or service with the Company. DSUs may be subject to performance conditions or other vesting conditions.
- *Other awards*. Other awards are awards that are convertible into or otherwise based on the common shares.

Performance Awards

The Long Term Incentive Plan provides for the grant of PSUs and allows awards to be made based upon, and subject to achieving, performance objectives. Performance objectives may relate to any, or any combination, of the following: shareholder return; net income or earnings measures, whether or not on an adjusted basis; return on equity; one or more operating ratios; share price; cash flow measures, whether or not on an adjusted basis; expenses; capital expenditures; working capital levels; borrowing levels, leverage ratios or credit rating measures; workplace safety goals; workforce satisfaction and diversity goals; employee retention; completion of key projects; implementation and achievement of synergy targets; joint ventures and strategic alliances; customer satisfaction measures; acquisitions and divestitures; and financings (issuance of debt or equity). When establishing performance objectives, the Human Resources Committee may exclude any or all "extraordinary items" as determined under applicable accounting standards. The foregoing list is for illustration only and is not exclusive.

Performance objectives may be measured either in absolute terms or relative to the performance of one or more similarly situated companies or a published index covering the performance of a number of companies and determined either on a consolidated basis or, as the context permits, with respect to one or more business units, divisions, subsidiaries, products, projects or geographic locations, or on combinations thereof.

The Human Resources Committee may provide that performance objectives will be adjusted in an objectively determinable manner to reflect events occurring during the performance period that affect the applicable performance objective.

Limits on Grants of Awards

The maximum aggregate number of common shares issuable to insiders of Hydro One at any time and the maximum aggregate number of common shares issued to an insider of Hydro One within any one year period under the Long Term Incentive Plan, and any other Hydro One security based compensation arrangements involving the newly-issued common shares, is 10% of the issued and outstanding common shares.

Vesting; Termination of Employment or Service

The Human Resources Committee has the authority to determine the vesting schedule applicable to each award, and to accelerate the vesting or exercisability of any award. The Human Resources Committee will determine the effect of termination of employment or service on an award. Unless otherwise provided by the Human Resources Committee, upon a termination of a participant's employment or service under the following circumstances, the following treatment will apply:

- *Death and Disability*. A portion of the next instalment of any awards due to vest shall immediately vest, such portion to equal to the number of awards next due to vest multiplied by a fraction the numerator of which is the number of days elapsed since the date of vesting of the last instalment of the awards (or if none have vested, the date of grant) to the date of death or disability and the denominator of which is the number of days between the date of vesting (or date of grant) and the date of vesting of the next instalment. Any associated performance targets will be deemed to have been met at the target performance level. Awards that have vested but are subject to exercise will remain exercisable until the earlier of 90 days after the participant's death, disability, or the award's normal expiration date.
- *Retirement*. All unvested awards shall continue to vest and be settled and exercised in accordance with their terms. A "Retirement" means a termination of employment where (a) in the case of the Chief Executive Officer and the Chief Executive Officer's direct reports, the retirement has been approved by the Board and the participant complies with such conditions as the Board may require, and in the case of other participants participating in the Hydro One Defined Benefit Pension Plan, the participant qualifies for retirement according to Plan rules and takes an immediate pension without obtaining access to the commuted value, and in the case of other participants participating in the new Hydro One defined contribution pension plan, the participant has reached age 65 with a minimum of 5 years of service or such lesser age and/or service thresholds as Hydro One may determine; (b) the participant has given formal notice of their intention to retire six months in advance or such lesser period as the Human Resources Committee may approve; (c) no cash severance payment or retirement allowance or equivalent is paid; and (d) the participant has complied with such transitional activities as may be reasonably required by Hydro One until the date the participant has ceased active employment.
- *Resignation by Participant (other than pursuant to a Retirement)*. All unvested awards will be forfeited. Awards subject to exercise will remain exercisable until the earlier of 90 days after the participant's termination of employment or the award's normal expiration date.
- *Termination by the Company for cause.* All awards, whether vested or unvested, will be forfeited and cancelled.
- *Termination by the Company other than for cause*. Awards other than Options and SARs will be forfeited. Options and SARs, to the extent vested, will remain exercisable until the earlier of 90 days after the participant's termination of service or the award's normal expiration date.
- *Termination by the Company other than for cause within 12 months following a change in control.* To the extent granted prior to the time of the change in control and then outstanding, all time-based awards will vest and be exercised or settled in accordance with their terms.

Non-Transferability of Awards

Awards under the Long Term Incentive Plan may not be sold, assigned, transferred, pledged or otherwise encumbered other than by the laws of succession or descent and distribution or, in the case of awards other than Options, to a permitted assign (within the meaning of the National Instrument 45-106 *Prospectus Exemptions* of the Canadian Securities Administrators).

Recovery of Compensation

The Human Resources Committee may provide that an award may be subject to potential cancellation, recoupment, rescission, payback or other action in accordance with the terms of any clawback, recoupment or similar policy adopted by the Company or as otherwise required by law or applicable stock exchange listing standards.

Change in Control

Subject to certain exceptions, in the event of a transaction pursuant to which a person or group (other than Hydro One Limited or a subsidiary of Hydro One Limited or the Province of Ontario) acquires direct or indirect beneficial ownership of, or acquires the right to exercise control or direction over, more than 50% of the outstanding voting securities of Hydro One Limited, including as a result of a take-over bid, an exchange of securities, an amalgamation, an arrangement, a capital reorganization or any other business combination or reorganization; the sale of all or substantially all of the assets of Hydro One Limited, other than to a wholly-owned subsidiary of Hydro One Limited; certain instances involving the dissolution or liquidation of Hydro One Limited; the acquisition of Hydro One in certain situations via consolidation, merger, exchange of securities, purchase of assets, amalgamation, statutory arrangement or otherwise; or as the Board may determine, the Human Resources Committee may provide for the conversion or exchange of outstanding awards for new awards or other securities of substantially equivalent value (or greater value) in any entity participating in or resulting from the change in control, or, if no equivalent awards are available, for the accelerated vesting or delivery of shares under awards, or for a cash-out of outstanding awards. The ownership of common shares of Hydro One Limited by the Province, together with the 10% ownership restriction referred to in "Governance and Relationship with Principal Shareholders", makes it less likely that such a change of control would occur.

Certain Adjustments

In the event of an extraordinary dividend, share dividend, share split or share combination (including a reverse stock split) or any recapitalization, business combination, merger, consolidation, spin-off, exchange of shares, liquidation or dissolution of Hydro One Limited or other similar transaction affecting the common shares, the Human Resources Committee will make adjustments as it determines in its sole discretion to the number of shares available for issuance under the Long Term Incentive Plan and/or the terms of any award, and the maximum number of shares that may be issued. The Human Resources Committee may also make adjustments of the type described in the preceding sentence to take into account distributions and events other than those listed above if it determines that adjustments are appropriate to avoid distortion in the operation of the Long Term Incentive Plan.

Amendment; Termination

The Human Resources Committee may amend the Long Term Incentive Plan or outstanding awards, or terminate the Long Term Incentive Plan as to future grants of awards, except that the Human Resources Committee will not be able to alter the terms of an award if it would affect materially and adversely a participant's rights under the award without the participant's consent (unless expressly provided in the Long Term Incentive Plan or the right to alter the terms of an award was expressly reserved by the Human Resources Committee at the time the award was granted). Shareholder approval will be required for any amendment to the Long Term Incentive Plan that increases the number of common shares available for issuance under the Long Term Incentive Plan or the individual award limitations specified in the Long Term Incentive Plan (except with respect to certain adjustments described above), permits non-employee directors to receive awards under the Long Term Incentive Plan, allows Options to be issued with an exercise price below fair market value on the date of grant, extends the term of any award granted under the Long Term Incentive Plan beyond its original expiration date or permits an award to be exercisable beyond 10 years from its grant date (except where an expiration date would have fallen within a blackout period of Hydro One Limited), permits awards to be transferred other than for normal estate settlement purposes, or deletes or reduces the range of amendments which require approval of the holders of voting shares of Hydro One Limited.

Short Term Incentive Plan

The Board will adopt a Short Term Incentive Plan for 2016 and future years. Cash award opportunities for executive officers, including the NEOs, and other management employees will be granted under the Short Term Incentive Plan. This summary is not a complete description of all provisions of the Short Term Incentive Plan and is qualified in its entirety by reference to the Short Term Incentive Plan.

For 2015, the short term incentive entitlement of NEOs other than the Chief Executive Officer and Chief Financial Officer will be determined in accordance with Hydro One's existing short term incentive plan. On a transitional basis, the Chief Executive Officer and Chief Financial Officer will receive a fixed amount in lieu of short term incentive equal to a pro rated portion of their respective annual target short term incentive opportunity.

Administration

The Short Term Incentive Plan will be administered by the Human Resources Committee. The Human Resources Committee has authority to interpret the Short Term Incentive Plan and awards granted under it, to determine eligibility for awards and to do all things necessary to administer the Short Term Incentive Plan. Any interpretation or decision by the Human Resources Committee will be final and conclusive on all participants.

Short Term Incentive Plan Participation

Executive officers and other management employees of the Company will be selected from time to time by the Human Resources Committee to participate in the Short Term Incentive Plan.

Awards

With respect to each award granted under the Short Term Incentive Plan, the Human Resources Committee will establish the performance criteria applicable to the award and the period over which performance will be measured, the amount or amounts payable if the performance criteria are achieved, and such other terms and conditions as the Human Resources Committee deems appropriate.

Performance Criteria

Awards under the Short Term Incentive Plan will be made based on, and subject to achieving, performance criteria established by the Human Resources Committee, which may be applied to a participant or participants on an individual basis, to a business unit or division, or to the Company as a whole.

Payment under an Award

A participant will be entitled to payment under an award only if all conditions of payment have been satisfied in accordance with the Short Term Incentive Plan and the terms of the award. The Human Resources Committee will determine the payment date or dates for awards under the Short Term Incentive Plan, which will generally be no later than mid-March of the calendar year following the year in which the relevant performance period ended. Following the close of the performance period, the Human Resources Committee will determine whether and to what extent the applicable performance criteria have been satisfied. The Human Resources Committee will then determine the actual payment, if any, under each award. The Human Resources Committee has the sole and absolute discretion to reduce the actual payment to be made under any award. A participant may defer payment of an award subject to the requirements of applicable law.

Recovery of Compensation

Awards under the Short Term Incentive Plan will be subject to forfeiture, termination and rescission, and a participant who receives a payment pursuant to the Short Term Incentive Plan may be obligated to return such payment to the Company, in accordance with the terms of any clawback, recoupment or similar policy adopted by the Company, or as otherwise required by law or applicable stock exchange listing standards.

Amendment

The Human Resources Committee may amend the Short Term Incentive Plan at any time.

Pension Plan Benefits

New Pension Arrangements

The Company intends to establish a defined contribution registered pension plan for employees in respect of services provided. The Company will match the contributions of participating employees to the defined contribution pension plan on the basis and to the extent of the percentages specified in the plan. The Chief Executive Officer and Chief Financial Officer will participate in the defined contribution pension plan and supplementary executive retirement plan when they are established in 2016.

The Company expects to make a contribution to Mr. Schmidt's and Mr. Vels' pension arrangements in respect of 2015, once these are established following closing of this offering. In each case, the contribution will be based on 9% of his base salary plus short term incentive (up to a maximum of 50% of base salary) pro rated for the period since his date of hire. The terms of the defined contribution supplementary executive retirement plan are not currently known. The Company anticipates that the 2015 contribution will be credited to the defined contribution supplementary executive retirement plan during 2016 and it is not expected that this contribution will be increased with interest.

Existing Pension Arrangements

The Company established a defined benefit registered pension plan (the "**Hydro One Defined Benefit Pension Plan**") on December 31, 1999. Hydro One Inc. manages and invests the assets and liabilities of the pension fund as plan sponsor and administrator of the plan.

The current NEOs (other than the Chief Executive Officer and Chief Financial Officer) participate in the Hydro One Defined Benefit Pension Plan. The benefits for these individuals are calculated in a manner consistent with all other Hydro One employees, as described below. The Company has closed participation in the Hydro One Defined Benefit Pension Plan to externally hired Company management entrants. It is intended that new externally hired executive officers of the Company will participate in the Company's defined contribution pension plan.

For each year of credited service under the Hydro One Defined Benefit Pension Plan, to a maximum of 35 years, the benefit provided for each of the employees who participate in the plan is equal to 2% of the member's average base annual earnings during the 36 consecutive months (60 consecutive months for management employees hired on or after January 1, 2004) when his or her base annual earnings were highest. Base annual earnings consist of the member's salary and 50% of his or her short term incentive.

The approximate projected credited years of service that each applicable NEO will have if he or she works until the age of 65 is as follows: Carmine Marcello – 35 years, Sandy Struthers – 24 years and Robert Cultraro – 28.2 years. This pension is reduced by 0.625% of the member's average base annual earnings up to the average year's maximum pensionable earnings during the 36 consecutive months (60 consecutive months for management employees hired after January 1, 2004) when his or her base earnings were highest. The reduction is intended to offset Canada Pension Plan benefits.

The plan terms also include a bridge pension which is payable from the date of retirement to age 65 for all members except for management employees hired on or after January 1, 2004. The Hydro One Defined Benefit Pension Plan provides for early retirement with an unreduced pension at the earlier of age 65 and the attainment of years of age plus continuous employment totalling 82 or more (years of age plus credited service totalling 85 for management employees hired on or after January 1, 2004). A plan member who is not eligible for an unreduced pension can retire with a reduced pension any time after attaining age 55.

Pension benefits payable to pensioners, beneficiaries and terminated employees with deferred pensions are increased annually, effective January 1 of each year equal to 100% of the increase in the Ontario consumer price index for the 12 month period ending in June of the previous year (75% for management employees hired on or after January 1, 2004). The normal form of pension for a member who does not have a spouse at retirement is a pension payable for life and guaranteed for five years, payable to an estate if not paid to the retiree. The normal form of pension for a member who has a spouse at retirement is a pension payable for the life of the member, and continuing after the member's death to his or her spouse at the rate of 66 2/3% of the amount the member was receiving.

The following table summarizes the following projected information for the NEOs intended to be participating in the Company's defined benefit pension plan arrangements as at December 31, 2015:

Named Executive Officer	Number of years credited service[(1)]	Annual benefits payable[(2)] ($) At Dec 31/15	At age 65	Opening present value of defined benefit obligation[(3)] ($)	Compensatory Change[(4)] ($) Service Cost[(5)]	Other[(6)]	Non-Compensatory Change[(7)] ($)	Closing present value of defined benefit obligation[(8)] ($)
Carmine Marcello . . . . *Special Advisor to the Chief Executive Officer and Chair of the Board*	28.1	344,000	428,000	8,595,000	299,000	(918,000)	375,000	8,351,000
Sandy Struthers . . . . *Chief Operating Officer*	15.9	145,000	219,000	2,968,000	181,000	(183,000)	145,000	3,111,000
Robert Cultraro . . . . *SVP, Chief Investment and Pension Officer*	9.8	55,000	158,000	886,000	83,000	(29,000)	58,000	998,000

Notes:

(1) As at December 31, 2015.

(2) For service up to December 31, 2015 and up to the normal retirement age of 65.

(3) The opening present value of the defined benefit obligation is the value of the projected pension earned for service as of December 31, 2014. The values have been determined using the same actuarial assumptions used for determining the pension plan obligations at December 31, 2014 as disclosed in the notes to Hydro One Inc.'s 2014 consolidated financial statements, based on the actual earnings for 2014 and adjusted to reflect expected increases in pensionable earnings.

(4) Reconciliation of the present value of the defined benefit obligation from December 31, 2014 to December 31, 2015. The present value of the defined benefit obligations reflects the impact of the annual bonus earned in the year even though it is paid in the following year.

(5) Value of the projected pension earned for service in the current fiscal year (reduced by the NEO's own contributions).

(6) Value of the increase or decrease in the present value of the defined benefit obligation that relates to service prior to the current fiscal year is due to the differences between actual compensation for the year and the earnings increase assumptions for the year, assumed at the end of the prior year. When the actual earnings increase is not in line with the assumed level, it impacts the total defined benefit obligation in respect of past service. If the expected highest average earnings based on the most recent information is lower than the highest average earnings based on the prior year estimate, it results in a decrease in the defined benefit obligation.

(7) Value includes the impact of amounts attributable to interest accruing on the beginning-of-year obligation, changes in the actuarial assumptions, the NEO's own contributions and any other experienced gains and losses.

(8) The closing present value of the defined benefit obligation is the value of the projected pension earned for service to December 31, 2015. The values have been determined using the same actuarial assumptions used for determining the pension plan obligations at December 31, 2014 as disclosed in the notes to the 2014 consolidated financial statements, based on the actual earnings for 2014 and adjusted to reflect expected increases in pensionable earnings.

The amounts above make no allowance for the different tax treatment of the portion of pension not paid from the registered or qualified pension plans. All amounts shown above are estimated based on assumptions and represent contractual entitlements that may change over time.

The method and assumptions used to determine estimated amounts will not be identical to the method and assumptions used by other issuers and, as a result, the figures may not be directly comparable to other issuers.

Supplementary Pension Plan Benefits

Like benefits paid under registered pension plans of other Canadian companies, benefits payable under the Hydro One Defined Benefit Pension Plan and its planned new defined contribution registered pension plan will be restricted by the Tax Act. For example, in 2014, this limit on benefits would have affected members whose average annual earnings exceed approximately $155,000. Participants whose pensions would otherwise be restricted by the Tax Act participate in an unregistered supplementary pension plan that provides benefits equal to the difference between the Tax Act maximum pension benefits and the benefits determined in accordance with the formula set out in Hydro One's registered pension plan. The supplementary pension plan is unfunded and the additional retirement income is paid from general revenues. Hydro One's obligations to participants under the supplementary pension plan are secured by a letter of credit.

Effective December 31, 1999, the Company established the Hydro One Inc. Supplementary Pension Plan to provide supplementary pension benefits. On October 30, 2001, this plan was amended to require the establishment of a trust for the purpose of creating security for payment of the supplementary pension benefits provided for therein. This trust was constituted as a retirement compensation arrangement under the provisions of the Tax Act, and security was issued in the form of a letter of credit.

Termination and Change of Control Benefits

Each of the NEOs is a party to an employment agreement with Hydro One governing the terms of their employment. None of the NEOs have any rights or receive benefits that will be triggered on the closing of this offering.

Under their employment agreements, on termination of employment without cause each of Mr. Schmidt and Mr. Vels will be entitled to 24 months' pay in lieu of notice of termination, consisting of base salary and an amount in respect of short term incentive. For each of Messrs. Schmidt and Vels, the amount in respect of short term incentive will reflect the lower of his actual average annual bonus for the three prior years and his target bonus for the year in which termination occurs. Their awards under the Long Term Incentive Plan continue to vest for 90 days following termination. They will also be permitted to receive group health and welfare benefits for the lesser of 24 months or when alternative coverage has been secured. Payment of such amounts are conditional upon delivery of a full and final release document to the Company and compliance with post-employment covenants respecting non-competition, non-solicitation and non-disparagement and the maintaining the confidentiality of Hydro One's confidential information. For further details respecting the treatment of awards granted under the Long Term Incentive Plan in the event of termination without cause, see "– Long Term Incentive Plan".

Neither Mr. Schmidt nor Mr. Vels is entitled to receive any payment in the event of termination for cause or voluntary resignation. In the event either of them retires after giving six months prior notice with the approval of the Board, complies with such conditions as the Board may require in connection with its approval and as may be reasonably required to facilitate transitional matters and is paid no cash severance payment or retirement allowance or equivalent, then his long term incentive awards will continue to vest and be paid in accordance with their terms.

In the event that within 24 months following a change in control of the Company the employment of Mr. Schmidt or Mr. Vels is terminated by the Company without cause or by the executive with good reason, he will be entitled to the same benefits as on a termination without cause except that the provisions respecting unvested long term incentive awards will only apply to long term incentive awards which were rolled over on the change in control or were granted subsequently. "Change in control" has the meaning given in the Long Term Incentive Plan. As a result of limitations on the ownership of the Company's shares under the Electricity Act, there would have to be an amendment to such statute for a change in control to occur. "Good reason" means a material change in title, responsibilities or authority or a material reduction in salary or in short term and long term incentive opportunity.

With respect to the other NEOs, if their employment is terminated by Hydro One without cause, the following will apply: Mr. Marcello and Mr. Struthers are entitled to receive an amount equal to his base salary at the date of termination in equal monthly instalments for a period of 24 months and to receive benefits over the same period (including Short Term Incentive Plan payments equal to the average of the three previous Short Term Incentive Plan payments, payable in monthly instalments). Each of Mr. Marcello and Mr. Struthers would continue to earn credited service under the Hydro One Defined Benefit Pension Plan during such 24-month period. Continuation of benefits will also continue until expiry of the severance period, except for disability insurance and accrual of vacation. Regarding Mr. Cultraro, if his employment were terminated by Hydro One without cause, he is entitled to a lump sum payment equivalent to 12 months of base salary and to no other entitlements.

Upon retirement, NEOs other than the Chief Executive Officer and Chief Financial Officer are entitled to group health and welfare benefits identical to the retirement benefits provided to other management employees. No benefits are provided in the event of a termination of employment for any other reason in such NEOs' employment contracts.

The table below shows the incremental payments that would be made to the Company's NEOs upon the occurrence of certain events, if such events were to occur immediately following the completion of this offering.

Name	Event	Severance[(1)]
Mayo Schmidt *President and Chief Executive Officer*	Termination without Cause	$3,230,000
Michael Vels *Chief Financial Officer*	Termination without Cause	$1,600,000
Carmine Marcello *Special Advisor to the Chief Executive Officer and Chair of the Board*	Termination without Cause	$1,461,083
Sandy Struthers *Chief Operating Officer*	Termination without Cause	$1,192,667
Robert Cultraro *SVP, Chief Investment and Pension Officer*	Termination without Cause	$ 250,000

Notes:

(1) In the case of the Chief Executive Officer and Chief Financial Officer, severance payments are calculated based on the annualized salary and target short term incentive for fiscal 2015. For other NEOs, severance reflects their entitlements based on their current base salary and average short term incentive plan payments over the prior three years. The calculation of severance payments does not include any amounts payable with respect to the Long Term Incentive Plan as previously referenced.

Executive Officer Share Ownership Guidelines and Anti-Hedging Policy

Hydro One strongly supports share ownership by its Chief Executive Officer and senior executive team and, accordingly, has introduced minimum share ownership guidelines. The Chief Executive Officer and senior executive team can meet share ownership requirements through direct or beneficial ownership of the Company's common shares, including RSUs subject to time-vesting only granted under the Company's Long Term Incentive Plan. Individuals have until the later of five years from: (a) the closing date of this offering; and (b) the date they first became subject to these requirements in order to satisfy the share ownership requirements. Employees who were subject to these requirements and are promoted or appointed into a position that is subject to a higher share ownership requirement have three years from the date of their promotion or appointment to meet the higher minimum requirement.

The ownership requirements as a multiple of annual base salary are set forth in the table below:

Position	Multiple of Base Salary
Chief Executive Officer	5x
Chief Financial Officer and other direct reports to the Chief Executive Officer	3x
Other Senior Executive Officers	1x

Executives are prohibited from purchasing financial instruments that are designed to hedge, offset or otherwise reduce or limit their economic risk, including with respect to a decrease in market value of equity securities of the Company granted as compensation or held, directly or indirectly, by such individuals. Prohibited transactions include hedging strategies, equity monetization transactions, transactions using short sales, puts, calls, exchange contracts, derivatives and other types of financial instruments (including, but not limited to, prepaid variable forward contracts, equity swaps, collars and exchange funds), and the pledging of or granting of any other security interest in equity securities of the Company as security for any loan where recourse is limited to the pledged security.

DIRECTORS' COMPENSATION

Director Compensation

The by-laws of the Company provide that directors may receive such remuneration for their services as the Board may determine, together with reimbursement for all expenses incurred in fulfilment of their duties, including travel expenses.

Directors will receive 50% of their annual director retainer as an equity component in the form of common shares or director deferred share units ("**Director DSUs**"). Following completion of this offering, Hydro One will adopt a non-employee director deferred share unit plan providing for awards of Director DSUs to Hydro One directors other than the Chief Executive Officer. A Director DSU is an award that entitles the participant to receive following termination of service with Hydro One and its subsidiaries an amount equivalent to the value of a common share at settlement. Director DSUs vest immediately and accrue dividend equivalents when dividends are paid on the common shares. Directors may also elect to receive 100% of their compensation in DSUs. Pending the adoption of the non-employee director deferred share unit plan, the full amount of the director retainer payable shall be paid in cash.

The chart below outlines Hydro One's director compensation program.

	Cash Component	Equity Component	Total
Chair of the Board	$130,000	$130,000	$260,000
All Other Directors	$ 80,000	$ 80,000	$160,000
Committee Chair Retainers	$ 20,000	—	$ 20,000
Board / Committee Meeting Attendance		No Meeting Fees	

Directors also receive a reasonable per meeting allowance for travel time to attend meetings in accordance with the Company's approved policy. No additional compensation will be paid to the directors to prepare for Board or committee meetings.

Director Share Ownership Guidelines

Directors who are not also executive officers of Hydro One are subject to share ownership guidelines of 3x their total Board retainer (calculated including the equity portion), valued at the original grant value or acquisition cost, to be achieved within six years of the closing of this offering or the date of appointment to the Board. Directors can meet share ownership requirements through direct or beneficial ownership of Company common shares and Director DSUs.

SHARE GRANT PLANS

Hydro One Limited intends to establish an employee share grant plan for the benefit of certain members of the Power Workers' Union (the "**PWU Share Grant Plan**") and an employee share grant plan for the benefit of certain employees represented by The Society of Energy Professionals (the "**Society Share Grant Plan**").

Under the PWU Share Grant Plan, employees of Hydro One who are employees represented by the Power Workers' Union and who have been contributing to the Hydro One Defined Benefit Pension Plan as of April 1, 2015 will be eligible to receive common shares effective April 1 of each year (each, a "**Grant Date**") beginning April 1, 2017 up until the earlier of April 1, 2028 and the earlier of the date such eligible employee has more than 35 years of pensionable service under the Hydro One Defined Benefit Pension Plan and the date on which the eligible employee must, due to age, cease contributing to such plan under the current provisions of the Tax Act. The number of common shares granted to each eligible employee on each Grant Date will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by the offering price of the common shares being distributed under this prospectus. The aggregate number of common shares issuable under the PWU Share Grant Plan is expected to be limited to approximately 4,086,000 common shares.

Under the Society Share Grant Plan, employees of Hydro One who are employees represented by The Society of Energy Professionals and who have been contributing to the Hydro One Defined Benefit Pension Plan as of September 1, 2015 will be eligible to receive common shares effective April 1 of each year, beginning April 1, 2018 up until the earlier of April 1, 2029 and the earlier of the date such eligible employee has more than 35 years of pensionable service under the Hydro One Defined Benefit Pension Plan and the date on which the eligible employee must, due to age, cease contributing to such plan under the current provisions of the Tax Act. The number of common shares granted to each eligible employee on each Grant Date will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by the offering price of the common shares being distributed under this prospectus. The aggregate number of common shares issuable under the Society Share Grant Plan is expected to be limited to approximately 1,470,000 common shares.

The PWU Share Grant Plan and the Society Share Grant Plan are each expected to include customary anti-dilution provisions providing that the number of shares to which an employee is entitled shall be adjusted in the event that the common shares of Hydro One Limited are split, consolidated or reclassified, or in the event that there is a declaration of a special dividend or a dividend payable in common shares (other than a share dividend paid in lieu of ordinary cash dividends) or in the event of a merger or reorganization of Hydro One Limited in order to prevent dilution or enlargement of the share grants under the plan. Both plans will also include customary tax or other withholding provisions.

The Board may amend the PWU Share Grant Plan and the Society Share Grant Plan from time to time, without shareholder approval, provided however that shareholder approval will be required for the following amendments: (i) an increase in the number of common shares reserved for issuance under each plan; (ii) an amendment to the definition of "Eligible Employee" under each plan that would permit the inclusion and participation by non-employee directors; (iii) an amendment that permits equity based awards other than grants of common shares to be made under each plan; and (iv) an amendment to the provisions of the plan respecting matters requiring shareholder approval, other than the addition of matters to be subject to shareholder approval. Amendments to each of the PWU Share Grant Plan and the Society Share Grant Plan may not prejudice the right of any eligible employees to be granted common shares under such plan without the consent of the eligible employee. Any amendment to the PWU Share Grant Plan requires the approval of the Power Workers' Union and any amendment to the Society Share Grant Plan requires the approval of The Society of Energy Professionals.

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement between Hydro One Limited, Hydro One Inc., the Selling Shareholder and the Underwriters (the "**Underwriting Agreement**"), the Selling Shareholder has agreed to sell and the Underwriters have agreed to severally purchase, as principals, on the Closing Date, subject to the terms and conditions of the Underwriting Agreement, 81,100,000 common shares from the Selling Shareholder, at a price of $20.50 per share, for aggregate gross proceeds of $1,662,550,000 payable in cash to the Selling Shareholder against delivery of the common shares. The offering price of Hydro One Limited's common shares has been determined by negotiation between the Province and the Underwriters.

This offering is being made in each of the provinces and territories of Canada. Hydro One Limited's common shares will be offered in each of the provinces and territories of Canada through those Underwriters or their affiliates who are registered to offer the shares for sale in such provinces and territories and such other registered dealers as may be designated by the Underwriters. Subject to applicable law and the provisions of the Underwriting Agreement, the Underwriters may offer Hydro One Limited's common shares outside of Canada.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint, are subject to certain closing conditions and may be terminated upon written notice to Hydro One Limited and the Province upon the occurrence of certain stated events, including: (i) any material change or any change in a material fact in relation to Hydro One Limited which could be expected to result in the purchasers of a material number of common shares exercising their rights to withdraw from their purchase or would be expected to have a significant adverse effect on the market price or value of the common shares; (ii) certain events affecting the state of the financial markets; (iii) certain investigations, proceedings or orders made by a governmental authority in relation to Hydro One Limited which may prevent or restrict the distribution or trading of the common shares; (iv) any order is made by a securities regulatory authority which may restrict the distribution of the common shares, or proceedings are announced for such order which have not been rescinded or withdrawn; (v) any changes or proposed changes in law which could be expected to materially adversely affect the trading or distribution of the common shares or any other securities of Hydro One Limited; or (vi) the state of financial markets in Canada or the United States is such that, in the reasonable opinion of any of the Underwriters, the common shares cannot be marketed profitably. The Underwriters are, however, obligated to take up and pay for all of the common shares if any common shares are purchased under the Underwriting Agreement. The Province has agreed to pay the Underwriters' Fee, which will be equal to 1.0% of the gross proceeds of this offering for each common share sold to institutional investors and equal to 3.0% of the gross proceeds of this offering for each common share sold to other investors. The Underwriters are entitled under the Underwriting Agreement to customary indemnification against certain liabilities and expenses, including certain liabilities and related expenses under applicable securities legislation in connection with this offering.

There is currently no market through which Hydro One Limited's common shares may be sold, and purchasers may not be able to resell common shares purchased under this prospectus. This may affect the pricing of the common shares in the secondary market, the transparency and availability of trading prices, the liquidity of the common shares, and the extent of issuer regulation. The TSX has conditionally approved the listing of the common shares distributed under this prospectus on the TSX under the symbol "H". Listing will be subject to Hydro One Limited fulfilling all of the requirements of the TSX on or before January 25, 2016.

Hydro One Limited's common shares offered under this prospectus have not been, and will not be, registered under the 1933 Act or any U.S. state securities laws, and may not be offered or sold within the U.S. absent registration or an exemption from the registration requirements of the 1933 Act, and applicable U.S. state securities laws. Accordingly, except to the extent permitted by the Underwriting Agreement, the common shares may not be offered or sold within the U.S. Each Underwriter has agreed that it will not offer or sell common shares within the U.S., except in transactions exempt from the registration requirements of the 1933 Act and applicable U.S. state securities laws. The Underwriting Agreement provides that the Underwriters may re-offer and re-sell the common shares that they have acquired pursuant to the Underwriting Agreement to qualified institutional buyers in the U.S. in accordance with Rule 144A under the 1933 Act. The Underwriting Agreement also provides that the Underwriters may offer and sell the common shares outside the U.S. in accordance with Regulation S under the 1933 Act.

In addition, until 40 days after the commencement of this offering, an offer or sale of Hydro One Limited's common shares within the U.S. by any dealer (whether or not participating in this offering) may violate the registration requirements of the 1933 Act, unless such offer is made pursuant to an exemption from registration under the 1933 Act.

The common shares may also be sold internationally as permitted pursuant to private placement exemptions under local securities laws.

RBC Dominion Securities Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., TD Securities Inc., National Bank Financial Inc. and Desjardins Securities Inc. are subsidiaries or affiliates of lenders that have made the Liquidity Facility available to Hydro One Inc., which will become a subsidiary of Hydro One Limited prior to the closing of this offering. Hydro One will not receive any proceeds from the sale of the common shares by the Province. As such, none of the proceeds of this offering will be applied, directly or indirectly, by Hydro One to repay any indebtedness under the Liquidity Facility. As of the date of this prospectus, there was no outstanding indebtedness under the Liquidity Facility. In addition, RBC Dominion Securities Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., TD Securities Inc., National Bank Financial Inc. and Desjardins Securities Inc. are subsidiaries or affiliates of lenders that are anticipated to make the Operating Credit Facility available to Hydro One Limited and the New Term Facility available to Hydro One Inc. See "Pre-Closing Transactions". Although Hydro One Limited is not offering common shares pursuant to this offering, it may be considered a connected issuer of the Underwriters who are affiliates of such lenders for purposes of securities laws in Canada.

Price Stabilization, Short Positions and Passive Market Making

In connection with this offering, the Underwriters may over-allocate or effect transactions which stabilize or maintain the market price of Hydro One Limited's common shares at levels other than those which otherwise might prevail on the open market, including:

- stabilizing transactions,
- short sales,
- purchases to cover positions created by short sales,
- imposition of penalty bids, and
- syndicate covering transaction.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of Hydro One Limited's common shares while this offering is in progress. These transactions may also include making short sales of the common shares, which involve the sale by the Underwriters of a greater number of common shares than they are required to purchase in this offering. Short sales may be "covered short sales", which are short positions in an amount not greater than the Over-Allotment Option, or may be "naked short sales", which are short positions in excess of that amount.

The Underwriters may close out any covered short position either by exercising the Over-Allotment Option, in whole or in part, or by purchasing common shares in the open market. In making this determination, the Underwriters will consider, among other things, the price of common shares available for purchase in the open market compared with the price at which they may purchase common shares through the Over-Allotment Option.

The Underwriters must close out any naked short position by purchasing common shares in the open market. A naked short position is more likely to be created if the Underwriters are concerned that there may be downward pressure on the price of the common shares in the open market that could adversely affect prospective purchasers who purchase in this offering.

Any naked short position would form part of the Underwriters' over-allocation position and a prospective purchaser who acquires common shares forming part of the Underwriters' over-allocation position acquires such common shares under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

In addition, in accordance with policy statements of certain Canadian securities regulatory authorities and the Universal Market Integrity Rules for Canadian Marketplaces ("**UMIR**"), the Underwriters may not, at any time during the period of distribution, bid for or purchase common shares. The foregoing restriction is, however, subject to certain exceptions as permitted by such policy statements and UMIR. These exceptions include a bid or purchase permitted under the provisions of such policy statements and the UMIR relating to market stabilization and market balancing activities and a bid or purchase on behalf of a customer where the order was not solicited.

As a result of these activities, the price of Hydro One Limited's common shares may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the Underwriters at any time. The Underwriters may carry out these transactions on any stock exchange on which the common shares are listed, in the over-the-counter market, or otherwise.

The Selling Shareholder has granted to the Underwriters the Over-Allotment Option, exercisable, in whole or in part, for a period of 30 days from the Closing Date, to purchase up to 8,150,000 additional common shares, at the offering price, payable in cash against delivery of such additional common shares. The Over-Allotment Option is exercisable only for the purpose of covering over-allotments, if any. The Selling Shareholder will pay the Underwriters' Fee in respect of common shares sold pursuant to the exercise of the Over-Allotment Option.

The Underwriters propose to offer Hydro One Limited's common shares initially at the offering price stated on the cover page of this prospectus. After the Underwriters have made a reasonable effort to sell all of the common shares offered by this prospectus at that price, the initially stated offering price may be decreased, and further changed from time to time, by the Underwriters to an amount not greater than the initially stated offering price and, in such case, the compensation realized by the Underwriters will be decreased by the amount that the aggregate price paid by the purchasers for the common shares is less than the gross proceeds paid by the Underwriters to the Selling Shareholder.

Lock-Up Arrangements

Each of Hydro One Limited and the Selling Shareholder will agree in the Underwriting Agreement that, during the period beginning on the closing date of this offering and ending on the date that is 180 days following the closing date of this offering, each of Hydro One Limited and the Selling Shareholder will not, directly or indirectly, without the prior written consent of RBC Dominion Securities Inc. and Scotia Capital Inc., issue, sell, offer, grant any option, warrant or other right to purchase or agree to issue or sell, or otherwise lend, transfer, assign, pledge or dispose of (including without limitation by making any short sale, engaging in any hedging, monetization or derivative transaction or entering into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of common shares or other securities of the Hydro One Limited or securities convertible into, exchangeable for, or otherwise exercisable into common shares or other securities of Hydro One Limited, whether or not cash settled), in a public offering or by way of private placement or otherwise, any equity securities of Hydro One Limited or other securities convertible into, exchangeable for, or otherwise exercisable into common shares or other equity securities of Hydro One Limited, or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, other than: (i) the common shares sold to the Underwriters pursuant to this prospectus; (ii) common shares or other securities of Hydro One Limited issued as part of the Pre-Closing Steps; (iii) common shares issued or delivered under Hydro One Limited's dividend reinvestment plan; (iv) common shares sold pursuant to the transactions with the parties described under "Principal and Selling Shareholder" (provided that the transferee is subject to a resale restriction ending not later than the expiry of the 180 day period); or (v) as may be granted or issued in the ordinary course of business under Hydro One Limited's security-based compensation arrangements, or employee share ownership plans, or pursuant to the conversion, exchange or exercise of any securities so granted or issued.

OPTIONS TO PURCHASE SECURITIES

The Board has adopted the Long Term Incentive Plan as described in "Executive Compensation". Hydro One Limited has not to date granted any options or other entitlements to purchase its securities, whether under the Long Term Incentive Plan or otherwise.

Hydro One Inc. does not have a stock option or other form of equity-based compensation plan.

PRIOR SALES

On August 31, 2015, in connection with the incorporation of Hydro One Limited, Hydro One Limited issued 100,000 common shares to the Province for $1.00 per common share. In connection with the Pre-Closing Steps, prior to the closing of this offering, the Province will subscribe for an additional 2,600,000,000 common shares for $1.00 per common share in connection with the funding of amounts to pay the departure tax. The Province will also receive common shares and 16,720,000 Series 1 preferred shares from Hydro One Limited in consideration for the purchase of all of the issued and outstanding shares of Hydro One Inc. held by the Province by Hydro One Limited. The outstanding common shares of Hydro One Limited will be consolidated such that 595,000,000 common shares will be issued and outstanding immediately prior to the closing of this offering. The Province has entered into an agreement to sell, immediately following the closing of this offering, between 3,666,667 and 4,052,632 common shares to trusts for the benefit of the Power Workers' Union and between 1,840,000 and 2,033,684 common shares to trusts for the benefit of The Society of Energy Professionals, in each case, at the same price as the offering price of the common shares sold in this offering. See "Pre-Closing Transactions – Province's Share Purchase Arrangements".

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to Hydro One Limited, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, provided that on the Closing Date the common shares are listed on a "designated stock exchange" as defined in the Tax Act (which currently includes the TSX), the common shares acquired on the Closing Date pursuant to this offering will be qualified investments under the Tax Act for trusts governed by a registered retirement savings plan ("**RRSP**"), deferred profit sharing plan, registered retirement income fund ("**RRIF**"), registered education savings plan, registered disability savings plan, and a tax-free savings account ("**TFSA**").

Notwithstanding that the common shares may be qualified investments for a trust governed by an RRSP, RRIF or TFSA, the annuitant of an RRSP or RRIF or the holder of a TFSA will be subject to a penalty tax on the common shares held in such trust (and other tax consequences may result) if the common shares are a "prohibited investment" for the RRSP, RRIF or TFSA, as the case may be. The common shares will not be a "prohibited investment" in respect of such RRSP, RRIF or TFSA held by a particular holder or annuitant provided the holder or annuitant deals at arm's length with Hydro One Limited for purposes of the Tax Act and does not have a "significant interest" (as defined in the Tax Act for purposes of the prohibited investment rules) in Hydro One Limited. In addition, the common shares will generally not be a prohibited investment if such shares are "excluded property" as defined in the Tax Act for purposes of the prohibited investment rules. Shareholders should consult their own tax advisors as to whether the common shares will be a prohibited investment in their particular circumstances.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following summary describes the principal Canadian federal income tax considerations generally applicable to a purchaser who acquires as beneficial owner common shares pursuant to this offering and who, at all relevant times, for purposes of the Tax Act, (1) is, or is deemed to be, resident in Canada, (2) deals at arm's length with Hydro One Limited and the Underwriters; (3) is not affiliated with Hydro One Limited or any of the Underwriters; and (4) holds the common shares as capital property (a "**Holder**"). Generally, the common shares will be capital property to a Holder provided the Holder does not acquire or hold those common shares in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain Holders may be entitled to make or may have already made the irrevocable election permitted by subsection 39(4) of the Tax Act the effect of which may be to deem to be capital property any common shares (and all other "Canadian securities", as defined in the Tax Act) owned by such Holder in the taxation year in which the election is made and in all subsequent taxation years. Holders whose common shares might not otherwise be considered to be capital property should consult their own tax advisors concerning this election.

This summary is not applicable to (i) a purchaser that is a "specified financial institution"; (ii) a purchaser an interest in which is a "tax shelter investment"; (iii) a purchaser that is, for purposes of certain rules (referred to as the mark-to-market rules) applicable to securities held by financial institutions, a "financial institution"; (iv) a purchaser that reports its "Canadian tax results" in a currency other than Canadian currency; or (v) a purchaser that enters into, with respect to their common shares, a "derivative forward agreement", each as defined in the Tax Act. Such purchasers should consult their own tax advisors.

This summary is based on the current provisions of the Tax Act, and an understanding of the current administrative policies and assessing practices of the Canada Revenue Agency published in writing prior to the date hereof. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "**Proposed Amendments**") and assumes that all Proposed Amendments will be enacted in the form proposed. No assurances can be given that the Proposed Amendments will be enacted as proposed, or at all. This summary does not otherwise take into account or anticipate any changes in law or administrative policy or assessing practice whether by legislative, administrative or judicial action nor does it take into account tax legislation or considerations of any province, territory or foreign jurisdiction, which may differ from those discussed herein.

This summary is of a general nature only and is not, and is not intended to be, legal or tax advice to any particular shareholder. This summary is not exhaustive of all Canadian federal income tax considerations. Accordingly, prospective purchasers of common shares should consult their own tax advisors having regard to their own particular circumstances.

Taxation of Holders of Common Shares

Dividends

A Holder will be required to include in computing its income for a taxation year any dividends received or deemed to be received on the common shares. In the case of a Holder that is an individual (other than certain trusts), such dividends will be subject to the gross-up and dividend tax credit rules applicable to taxable dividends received or deemed to be received from taxable Canadian corporations, including the enhanced gross-up and dividend tax credit applicable to any dividends designated by Hydro One Limited as an eligible dividend in accordance with the provisions of the Tax Act. A dividend received by a Holder that is a corporation will generally be deductible in computing the corporation's taxable income. In certain circumstances, subsection 55(2) of the Tax Act (as proposed to be amended by Proposed Amendments released on July 31, 2015) will treat a taxable dividend received by a Holder that is a corporation as proceeds of disposition or a capital gain. Holders that are corporations should consult their own tax advisors having regard to their own circumstances.

A Holder that is a "private corporation", as defined in the Tax Act, or any other corporation controlled, whether because of a beneficial interest in one or more trusts or otherwise, by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), will generally be liable to pay a refundable tax of 33⅓% under Part IV of the Tax Act on dividends received or deemed to be received on the common shares to the extent such dividends are deductible in computing the Holder's taxable income for the taxation year.

The cost to a Holder of common shares for purposes of the Tax Act purchased on the reinvestment of dividends pursuant to the dividend reinvestment plan will be the price paid for such common shares. For the purpose of computing the adjusted cost base of such common shares to the Holder, the cost of such common shares will be averaged with the adjusted cost base of all other common shares held by the Holder as capital property at that time.

Dispositions

Generally, on a disposition or deemed disposition of a common share, a Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Holder of the common share immediately before the disposition or deemed disposition.

Generally, a Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "**taxable capital gain**") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Holder is required to deduct one-half of the amount of any capital loss (an "**allowable capital loss**") realized in a taxation year from taxable capital gains realized by the Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years, to the extent and under the circumstances prescribed by the Tax Act.

The amount of any capital loss realized by a Holder that is a corporation on the disposition or deemed disposition of a common share may be reduced by the amount of any dividends received by the Holder on such common share to the extent and under the circumstances prescribed by the Tax Act. Similar rules may apply where a common share is owned by a partnership or trust of which a corporation, trust or partnership is a member or beneficiary. Such Holders should consult their own tax advisors.

RISK FACTORS

Investing in Hydro One Limited's common shares involves risk. You should carefully consider the risks and uncertainties described below, together with all of the other information contained in this prospectus, including the consolidated financial statements and the related notes appearing at the end of this prospectus, before deciding to invest in Hydro One Limited's common shares. If any of the following risks actually occurs, the Company's business, prospects, operating results and financial condition could be materially adversely affected, the trading price of the common shares could decline and you could lose all or part of your investment. The risks and uncertainties described below are not the only ones the Company faces. Additional risks and uncertainties not presently known to the Company or that the Company currently believes to be immaterial may also adversely affect the Company's business.

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the Ontario Energy Board will not approve the Company's transmission and distribution revenue requirements requested in future applications for rates. Rate applications for revenue requirements are subject to the Ontario Energy Board's review process, which may involve participation from intervenors and, in certain circumstances, a litigated public hearing process. There can be no assurance that resulting decisions or rate orders issued by the Ontario Energy Board will permit Hydro One to recover all costs actually incurred, including operations, maintenance and administration costs, costs accumulated in other regulatory accounts (including, for instance, deferral and variance accounts), costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed return on equity depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance and administration costs above those included in the Company's approved revenue requirement, higher capital expenditures than those approved in rate decisions, or additional financing charges because of increased debt amounts or higher interest rates. The inability to obtain acceptable rate decisions or to otherwise recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations. Further, the Ontario Energy Board approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors.

If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the Ontario Energy Board would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler-than-normal summer or warmer-than-normal winter may reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful CDM programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The Ontario Energy Board's rate-setting model for distributors requires that the term of a custom rate application (distribution business) be a minimum five-year period. There are risks associated with forecasting over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable in future rates. This could have a material adverse effect on the Company.

The Ontario Energy Board has stated its intention to examine the policies that may apply to transmission rate-setting, and this may result in changes to the rate-setting model for transmission services. No specific changes have been proposed, and it is therefore too early to assess the impact of any such changes on the Company. However, a change to the rate-setting model for transmission services could result in a decrease in the Company's revenues or financial performance.

The Ontario Energy Board approves and periodically changes the return on equity for transmission and distribution businesses. The Ontario Energy Board may in the future decide to reduce its allowed return on equity for either of these businesses, or to modify the formula or methodology it uses to determine the return on equity. Any such reduction could reduce the net income of the Company.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the Ontario Energy Board, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the Ontario Energy Board. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the Ontario Energy Board may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While the Company expects all of its expenditures and regulatory assets to be fully recoverable after Ontario Energy Board review, any future regulatory decision to disallow or limit the recovery of such costs would lead to a lower-than-expected approved revenue requirement or rate base, potential asset impairment and charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Deferred Tax Asset

As a result of leaving the PILs regime and entering the corporate tax regime, Hydro One will recognize a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. Management believes this will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One. There is a risk that, in future rate applications, the Ontario Energy Board will reduce the Company's revenue requirement by all or a portion of those net cash savings. If the Ontario Energy Board were to reduce the Company's revenue requirement in this manner, it could have a material adverse effect on the Company.

Risks Relating to Other Applications to the Ontario Energy Board

The Company is also subject to the risk that it will not obtain required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the Ontario Energy Board are subject to Ontario Energy Board approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the Ontario Energy Board.

First Nations and Métis Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on Reserve lands, and lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although the Company has a recent history of successful negotiations and engagement with First Nations and Métis communities in Ontario, some First Nations and Métis leaders, communities and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may, on occasion, give rise to the Crown's duty to consult and potentially accommodate First Nations and Métis communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult a First Nations or Métis community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its members. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that the Company will manage them until it has obtained necessary authorizations to complete the title transfer. To occupy Reserves, the Company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal government (presently Aboriginal Affairs and Northern Development Canada) issuing a permit. Where the agreement and permit are for transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements and obtain federal permits, it may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if it is not able to recover them in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "– Health, Safety and Environmental Risk".

For instance, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licenses, with codes and rules issued by the Ontario Energy Board and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the NERC and NPCC. The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the Ontario Energy Board will approve the recovery of all of such incremental costs. Failure to obtain such approval could have a material adverse effect on the Company.

There is the risk that new legislation, regulations or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks or any other potentially catastrophic events. Although constructed, operated and maintained to industry standards, the Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity. Hydro One's risk is partly mitigated because its transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss, Hydro One would apply to the Ontario Energy Board for recovery of such loss; however, there can be no assurance that the Ontario Energy Board would approve any such applications, in whole or in part, which could have a material adverse effect on the Company.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain lower levels of information technology security for its assets that are not subject to these mandatory standards. Unauthorized access to corporate and information technology systems or cyber-attacks could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. In addition, in the normal course of its operations, the Company may collect, process or retain access to confidential customer, supplier, counterparty or employee information, which could be exposed in the event of a cyber-security incident.

Hydro One mitigates these risks, including through the use of security event management tools on its power and business systems, by separating its transmission and distribution system networks from its other business system networks, by performing scans of its systems for known cyber threats and by providing company-wide awareness training to Hydro One personnel. Hydro One also engages the services of external experts to evaluate the security of its information technology infrastructure and controls. Hydro One performs vulnerability assessments on its critical cyber assets and it ensures security and privacy controls are incorporated into new information technology capabilities. Although these security and system disaster recovery controls are in place, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2014, approximately 17% of the Company's employees were eligible for retirement and by the end of 2015 up to 19% could be eligible. These percentages are not evenly spread across the Company's workforce, but tend to be most significant in the most senior levels of the Company's staff and especially among management and executive staff. Accordingly the Company's continued success will be tied to its ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and to meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry to be highly competitive in the future. Many of the Company's current employees and many of the potential employees it would seek in the future possess skills and experience that would also be highly sought after by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the Power Workers' Union or The Society of Energy Professionals. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company recently reached an agreement with the Power Workers' Union for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with The Society of Energy Professionals with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a three-year term, covering the period from May 1, 2014 to April 30, 2017, although this remains subject to ratification by the Canadian Union of Skilled Workers. However, there can be no assurance that future collective agreement renewals with these unions or that collective agreements with the other unions with which Hydro One has contractual relationships, will be renewed on acceptable terms. The Company faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its license requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness, to fund the payment of an $800 million cash dividend or make a return of capital to the Province prior to the closing of this offering, and to fund a portion of capital expenditures. Hydro One Inc. has substantial amounts of existing debt, including $550 million maturing in 2015, $500 million maturing in 2016, and $600 million maturing in 2017. The Company plans to incur capital expenditures of approximately $1,564 million in 2015 and $1,535 million in 2016. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow substantial amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The Ontario Energy Board-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2016 net income by approximately $21 million and its distribution business' 2016 net income by approximately $14 million. The Company's net income is adversely impacted by rising interest rates as the Company's maturing long-term debt is refinanced at market rates. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, entering into master agreements which enable net settlement**,** and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the Ontario Energy Board's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments or replacements of its transmission and distribution infrastructure. The risk of distribution equipment failures is higher due to the lack of real-time monitoring of these assets. The connection of large amounts of distributed generation on the distribution network has resulted in more equipment usage than in the past for the Company. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. Approvals may also include *Environmental Assessment Act* (Ontario), approvals which require public meetings, and appropriate engagement with First Nations and Métis communities or receipt of Ontario Energy Board approvals which may require early access to property or expropriation. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required regulatory approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality, both of which could have a material adverse effect on the Company.

External factors are considered in the Company's planning process. However, if the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce transmission capacity, compromise the reliability of the Company's transmission system or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Competitive bidding processes may become a more common means of selecting developers of large transmission projects. To date, there has been only one transmission project, the East-West Tie Line, which has been the subject of a competitive bidding process initiated by the Ontario Energy Board. However, this may change in the future. Increased competition for the development of large transmission projects could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, this would reduce the Company's share of Ontario's transmission network.

Health, Safety and Environmental Risk

Hydro One's health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of the Board that has governance over health, safety and environmental matters (see "Directors and Management of the Company – Committees of the Board – Health, Safety, Environment and First Nations & Métis Committee"). However, given the territory that the Company's system encompasses and the amount of equipment that it owns, the Company cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to the Company. The following are some of the areas that may have a significant impact on the Company's operations.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Hydro One currently has a voluntary land assessment and remediation program for off-site migration in place to identify and, where necessary, remediate historical contamination that has resulted from past operational practices and uses of certain long-lasting chemicals at the Company's facilities. Any contamination of the Company's properties could limit its ability to sell these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

Although Hydro One is not a large emitter of greenhouse gases, the Company monitors all of these emissions and has a management plan in place to track and report on all sources, including sulphur hexafluoride or "SF6". In addition, the Company recognizes the risks associated with potential climate change and has developed plans to respond as appropriate.

The Company anticipates that all of its future environmental expenditures will continue to be recoverable in future rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are minimally required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2013, and was filed in June 2014, covering a three year period from 2014 to 2016. Hydro One contributed approximately $160 million in respect of 2013, approximately $174 million in respect of 2014, and will contribute approximately $174 million by the end of 2015 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2015 are expected to continue to be significant; actual amounts will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. A determination by the Ontario Energy Board that some of the Company's pension expenditures are not recoverable from customers could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

The Ontario Energy Board has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. See "– Other Post-Employment and Post-Retirement Benefits Risks". The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time.

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Should any element of total compensation costs be disallowed in whole or part by the Ontario Energy Board and not be recoverable from customers in rates, the costs could be material and could lead to changes to the Company's results of operations and decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. The Ontario Energy Board has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. The objectives of the consultation are to develop standard principles to guide the Ontario Energy Board's review of pension and other post-employment and post-retirement benefits costs in the future, to establish specific information requirements for application and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Consistent with Hydro One's strategy of reducing operating costs, it has entered into an outsourcing arrangement with Inergi LP. See "Business of Hydro One – Employees and Outsourced Services". If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected, the Company could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the Company's transmission corridor lands underlying its transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company.

Risks Relating to the Company's Relationship with the Province

Ownership by the Province and Voting Power

The Province will own approximately 85% of the common shares immediately following this offering and the share purchase arrangements referred to in "Principal and Selling Shareholder – Share Purchase Arrangements with the Province" (84% of the common shares if the Over-Allotment Option is exercised in full). See "Principal and Selling Shareholder". In addition, the Electricity Act restricts the Province from selling Voting Securities (including common shares) of any class or series if it would own less than 40% of the outstanding number of Voting Securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. See "Governance and Relationship with Principal Shareholder – Province's Ownership of Common Shares and Preferred Shares". Accordingly, the Province is expected to continue to maintain a significant ownership interest in Voting Securities of Hydro One Limited for an indefinite period.

As a result of its significant ownership of the common shares, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject only to the restrictions in the Governance Agreement. While, with respect to its ownership interest in Hydro One Limited, the Province has agreed to engage in the business and affairs of Hydro One Limited only as an investor and has stated its intention to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, the Governance Agreement preserves the Province's right to vote its common shares in its sole interest, which may not be aligned with the interests of other shareholders. See "Governance and Relationship with Principal Shareholder – Governance Agreement – Governance Principles".

The Share Ownership Restrictions and the Province's significant ownership of common shares together effectively prohibit one or more persons acting together from acquiring control of Hydro One Limited. They also may limit or discourage transactions involving other fundamental changes to Hydro One Limited and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement.

Continued Influence by the Province

Historically, as the sole shareholder of the Company, the Province has exercised significant influence over the business and affairs of the Company by directing corporate actions or strategies through unanimous shareholder declarations that removed authority from the board, by making appointments to the board and informally, through the interaction of Ministers, ministerial staff and officials with executives of the Company. In exercising this influence, the Province has been free to pursue its policy objectives rather than exclusively commercial interests of the Company. See "Interests of Management and Others in Certain Material Transactions – Relationships with the Province and Other Parties".

Under the Governance Agreement, the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager and has agreed to other restrictions and limitations with respect to the governance of the Company and the Province's rights as a holder of Voting Securities. See "Governance and Relationship with Principal Shareholder – Governance Agreement."

There is a risk, however, that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Under the Governance Agreement, the Province is entitled to nominate 40% of the directors of Hydro One Limited (except where the Province ceases to own 40% of the Voting Securities, in which case it will be entitled after a period of time to nominate its proportionate share of the directors of Hydro One Limited as set forth in "Governance and Relationship with Principal Shareholder – Governance Agreement – Nomination of Directors – Board Nominees") and all directors, other than the Chief Executive Officer, including those nominated by the Province, are required to be independent of the Province. See "Governance and Relationship with Principal Shareholder – Governance Agreement – Nomination of Directors – Director Qualification Standards". In addition, under the Governance Agreement, the appointment of both the Chief Executive Officer and the Chair of the Board must be approved (and confirmed annually) by a special resolution of the Board passed by at least two-thirds of the votes cast at a meeting of the Board. See "Governance and Relationship with Principal Shareholder – Governance Agreement – Board Approvals Requiring a Special Resolution of the Directors".

There is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One Limited. This, combined with the fact certain matters require a two-thirds vote of the Board could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights

The Province is required under the Governance Agreement to vote in favour of all director nominees of Hydro One Limited. That obligation is subject, however, to the Province's overriding right to withhold from voting in favour of all director nominees and its right to seek to remove and replace the entire Board, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. If the Province exercises those rights, any new nominees proposed for election or appointment must be nominated in accordance with the Governance Agreement and meet the independence and qualification standards, and the Province may not re-nominate any of the directors who have been removed. See "Governance and Relationship with Principal Shareholder – Governance Agreement – Election and Replacement of Directors". In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation

Under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One Limited as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario. As a result, the Province has restricted the manner in which it may seek to influence Hydro One Limited. See "Governance and Relationship with Principal Shareholder – Governance Agreement." Accordingly, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on Hydro One Limited.

Prohibitions on Selling the Company's Transmission or Distribution Business

The Electricity Act prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the Ontario Energy Board. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

10% Ownership Restriction

As a result of the Share Ownership Restrictions, no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities of Hydro One Limited, including the common shares, other than the Province and other than an underwriter who holds the Voting Securities solely for the purpose of distributing Voting Securities to purchasers who comply with the Share Ownership Restrictions. A holder of Voting Securities who contravenes the Share Ownership Restrictions may also have its Voting Securities sold or redeemed and have dividend and voting entitlements on its Voting Securities suspended. See "Governance and Relationship with Principal Shareholder – 10% Ownership Restriction". The Share Ownership Restrictions also effectively prohibit one or more persons acting together from acquiring control of Hydro One Limited, including pursuant to a change of control transaction in which holders of Voting Securities could otherwise receive a premium for their Voting Securities. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other Voting Securities.

Future Sales of Common Shares by the Province

The Province has indicated that it currently intends to sell further common shares over time, until it holds approximately 40% of the common shares, subject to the selling restrictions agreed with the Underwriters. See "Plan of Distribution". The Registration Rights Agreement also grants the Province the right to request that Hydro One Limited file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares. See "Governance and Relationship with Principal Shareholder – Province's Ownership of Common Shares and Preferred Shares – Registration Rights Agreement". Future sales of common shares by the Province, or the perception that such sales could occur, may materially adversely affect market prices for the common shares and impede Hydro One Limited's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One Limited may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of Voting Securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. See “Governance and Relationship with Principal Shareholder – Governance Agreement – Election and Replacement of Directors”. Hydro One Limited’s ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province’s actions. A remedy of damages would be available to Hydro One Limited, but damages may not be an effective remedy, depending on the nature of the Province’s non-compliance with the Governance Agreement.

Potential Difficulties in Enforcing Civil Liabilities Against the Province, Hydro One Limited and other Persons

Under the securities legislation of Ontario and Newfoundland and Labrador, the statutory remedies of rescission or damages where the prospectus or any amendment contains a misrepresentation are not available against the Province, as selling shareholder or as a promoter of Hydro One Limited. It is also possible, based on prior court decisions, that a claim against the Province based on these statutory remedies would have to be brought in the Ontario courts, rather than in the courts of the purchaser’s province or territory of residence. If the claim was brought in the Ontario courts, and Ontario law was applied in respect of the claim, the statutory remedies would not be available against the Province. Alternatively, if a purchaser of common shares were to successfully assert a statutory misrepresentation claim against the Province in a jurisdiction other than Ontario, the resulting judgment may not be enforceable in Ontario for reasons which include that an Ontario court could conclude that it would be contrary to Ontario public policy to do so. Nonetheless, recourse may continue to be available against Hydro One Limited and any other parties that may be liable for any such misrepresentation.

Hydro One Limited is incorporated under the laws of Ontario, Canada and substantially all of the Company’s assets are located in Canada. Substantially all of the directors and officers of Hydro One Limited, and some experts named in this prospectus reside or are located in Canada, and their assets are located in Canada. As a result, it may be difficult for non-Canadian or other investors to effect service of process outside of Canada against Hydro One Limited the directors and officers of Hydro One Limited or these experts or to sue Hydro One Limited or those others in the United States or other courts. If a lawsuit were successful, it may be difficult to collect any money awarded.

In relation to potential claims by U.S. investors, the *United States Foreign Sovereign Immunities Act of 1976* (the “**FSIA**”) provides that, subject to existing international agreements to which the United States was a party at the time of the enactment of the FSIA, a foreign state or any agency or instrumentality of a foreign state is immune from U.S. federal and state court jurisdiction unless a specific exception to the immunity applies. One such exception applies to claims arising out of “commercial activity” by a foreign state or its agency or instrumentality. However, it is not certain that a court would consider any acts or omissions by Hydro One Limited, Hydro One Inc. or the Province in connection with this offering or otherwise to be “commercial activities” under the FSIA. Absent an applicable exception from immunity under the FSIA, any attempt to assert a claim against Hydro One Limited, Hydro One Inc. or the Province alleging a violation of the U.S. securities laws resulting from an alleged material misstatement in or material omission from this prospectus, or any other act or omission in connection with this offering, may be barred. Further, absent an applicable exception from immunity under the FSIA, any attempt to assert a claim against Hydro One Limited, Hydro One Inc. or the Province or any of their respective agents or employees alleging any other complaint, including as a result of any future action by the Province as a shareholder of Hydro One Limited, may also be barred.

In addition, even if a U.S. judgment could be obtained in such an action, the results of such judgment may not be enforceable in Ontario.

Risks Relating to this Offering

Absence of a Prior Public Market

There is currently no public market for Hydro One Limited’s common shares. The offering price of the common shares offered hereunder has been determined by negotiation between the Province and the Underwriters. The Company cannot predict the price at which Hydro One Limited’s common shares will trade upon closing and there can be no assurance that an active trading market will develop after closing or, if developed, that such a market will be sustained. In addition, if an active public market does not develop or is not maintained, investors may have difficulty selling their common shares.

Potentially Volatile Market Price for Common Shares

The market price for Hydro One Limited's common shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Company's control, including, but not limited to, the following: (i) actual or anticipated fluctuations in the Company's quarterly results of operations; (ii) changes in forecasts, estimates or recommendations of securities research analysts regarding the Company's future results of operations or financial performance; (iii) changes in the economic performance or market valuations of other issuers that investors deem comparable to the Company; (iv) addition or departure of the Company's executive officers and other key personnel; (v) increases or decreases in the amount of dividends to be paid or expected to be paid by the Company; (vi) release or expiration of lock-up or other transfer restrictions on outstanding common shares; (vii) sales or anticipated sales of additional common shares by Hydro One Limited or the Selling Shareholder; (viii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Company or its competitors; and (ix) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Company's industry or target markets.

Financial markets may experience significant price and volume fluctuations that affect the market prices of equity securities of public entities, even though unrelated to the operating performance, underlying asset values or prospects of such entities. Accordingly, the market price of Hydro One Limited's common shares may decline even if its operating results, underlying asset values or prospects have not changed. As well, certain institutional investors may base their investment decisions on consideration of the Company's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to satisfy such criteria may result in limited or no investment in, or divestiture of the common shares by those institutions, which could materially adversely affect the trading price of the common shares. There can be no assurance that continuing fluctuations in price and volume will not occur. If such increased levels of volatility and market turmoil occur or continue for a protracted period of time, the Company's operations and the trading price of Hydro One Limited's common shares may be materially adversely affected.

Payment of Dividends

Payment of dividends is dependent on cash flows of the Company's business and subject to change. The declaration and payment of future dividends will be at the discretion of the Board, may be subject to restrictions under Hydro One Limited and Hydro One Inc.'s credit facilities and may be affected by various other factors, including the Company's revenues, financial condition, acquisitions and legal, regulatory or contractual restrictions. There can be no assurance that Hydro One Limited will be in a position to pay dividends at the rate anticipated in this prospectus (or at all) in the future. A reduction or cessation of the payment of dividends could materially adversely affect the trading price of the common shares.

Dilution

The issuance of additional common shares by Hydro One Limited may have a dilutive effect on the interests of Hydro One Limited's shareholders. The number of common shares that Hydro One Limited is authorized to issue is unlimited. Hydro One Limited may, in its sole discretion, subject to applicable laws and the rules of the TSX and any stock exchange on which its securities may be listed from time to time, issue additional common shares from time to time (including pursuant to the Company's Long Term Incentive Plan, the PWU Share Grant Plan and the Society Share Grant Plan), and the interests of shareholders may be diluted thereby.

Securities Analysts' Research or Reports Could Impact Price of Common Shares

The trading market for Hydro One Limited's common shares may be facilitated in part by the research and reports that industry or financial analysts publish about the Company or its business. If no or few analysts commence coverage of the Company, the trading price of the common shares could be lower than otherwise. Even if the Company does obtain analyst coverage, if one or more of the analysts covering the Company's business downgrade their evaluations of Hydro One Limited's common shares or share price, the price of the common shares could decline. If one or more of these analysts cease to cover Hydro One Limited's common shares, the Company could lose visibility in the market for its shares, which in turn could cause Hydro One Limited's common share price to decline.

Tax Risks Relating to this Offering

Hydro One Inc.'s liability for payment-in-lieu of tax under the Electricity Act for the taxation year that includes August 31, 2015 will be impacted by the fair market value of the shares and debt of Hydro One Brampton Networks Inc. transferred, at the Province's direction, to a company wholly-owned by the Province on August 31, 2015 by way of a dividend-in-kind and a return of capital, respectively. No advance ruling has been obtained from the Ministry of Finance (Ontario) as to the valuation of such shares and debt at the time of these dispositions. The Company could be materially adversely affected if the valuation of such shares and debt is reassessed or challenged.

As a result of this offering, Hydro One Limited and each of its subsidiaries will lose its tax exempt status and will be subject to income tax under the Tax Act, the *Taxation Act, 2007* (Ontario), and any other provincial or income tax statute applicable after the loss of such status. Despite the fact that Hydro One has made payments in lieu of tax, certain taxation issues may arise as a result of Hydro One's change in tax status which could negatively impact Hydro One and which may subject Hydro One to various types of tax. Hydro One has taken, and expects in the future to take, actions to minimize these potential impacts. No advance income tax ruling has been obtained from the Canada Revenue Agency in respect of any potential impacts.

Holding Company Risk

Following completion of this offering, Hydro One Limited will be a holding company and a substantial portion of its assets will be the shares of its subsidiaries. As a result, prospective purchasers of common shares are subject to the risks attributable to Hydro One Limited's subsidiaries. As a holding company, Hydro One Limited will conduct substantially all of its business through its subsidiaries, which will generate substantially all of its revenues. Consequently, Hydro One Limited's cash flows and ability to complete current or desirable future enhancement opportunities are dependent on the earnings of its subsidiaries and the distribution of those earnings to Hydro One Limited. The ability of these entities to pay dividends and other distributions will depend on their operating results and will be subject to applicable laws and regulations which require that solvency and capital standards be maintained by such companies and contractual restrictions contained in the instruments governing their debt. In the event of a bankruptcy, liquidation or reorganization of any of Hydro One Limited's subsidiaries, holders of indebtedness and other creditors will generally be entitled to payment of their claims from the assets of such subsidiaries before any assets are made available for distribution to Hydro One Limited.

Pro Forma Financial Information

In preparing the unaudited pro forma condensed consolidated financial statements of Hydro One Inc. appearing elsewhere in this prospectus, the Company has given effect to certain transactions, as described in the notes to such financial statements. While management believes that the estimates and assumptions underlying the pro forma condensed consolidated financial statements are reasonable, such assumptions and estimates, including with respect to the annual net cash savings due to the reduction of cash taxes payable by Hydro One, may be materially different than the Company's actual results and experience in the future.

First Nations and Métis Proceedings

Certain First Nations and Métis organizations have asserted that the Province has an obligation to consult with them in respect of asserted potential adverse effects of the Province's proposed sale of common shares in this offering on their Aboriginal and treaty rights. Whether the Province has a duty to consult or not, it has indicated that it is in discussions regarding potential equity participation by the First Nations. The Company understands that these discussions focus on facilitating equity participation for such communities through future offerings by the Province. These discussions are ongoing and are not expected to affect the number of shares available for purchase in this offering. In addition, the Métis Nation of Ontario has expressed an interest in a dialogue with the Province in relation to this offering. The Province has indicated that it is also prepared to engage in a dialogue with the Métis in relation to broadened ownership of the Company. See "Principal and Selling Shareholder".

In addition, if a duty to consult exists in respect of this offering, it would rest with the Province and not Hydro One Limited and its subsidiaries. Broadening the ownership of Hydro One Limited will not alter the regulatory framework under which the Company operates and in which consultation with First Nation and Métis communities occurs, nor will it affect the Province's duty to consult, as appropriate.

To date, Canadian courts have been reluctant to enforce Aboriginal or treaty rights in a manner that would disturb established third party ownership interests, and the Province is not aware of any Canadian case where a court has unwound a public offering (whether as a result of an alleged breach of a duty to consult or otherwise). Accordingly, the Province has indicated that it considers it unlikely that any rights of holders of common shares that have been sold by the Province would be adversely affected by a claim that the Province has breached its duty to consult in respect of this offering. It is nevertheless possible that one or more First Nation or Métis organizations may commence legal proceedings in relation to this offering, seeking remedies that could include injunctive relief, damages or rescission of this offering.

PROMOTERS

Hydro One Inc. has taken the initiative in founding and organizing Hydro One Limited and may therefore be considered a promoter of Hydro One Limited for the purposes of applicable securities legislation. Hydro One Inc. will be Hydro One Limited's wholly owned subsidiary and will not hold any common shares or preferred shares of Hydro One Limited following the closing of this offering. Hydro One Inc. will not receive any benefits or proceeds, directly or indirectly, in connection with this offering. See "Corporate Structure – Corporate Structure and Subsidiaries".

Neither Hydro One Limited nor the Province is of the view that the Province is a promoter of Hydro One Limited for the purpose of this offering. However, as the Province may be perceived as having taken the initiative in founding, organizing or substantially reorganizing the business of Hydro One and who, in connection thereof, received consideration from the proceeds of the sale of common shares, the Province may be considered a promoter of Hydro One Limited for the purposes of applicable securities legislation. Accordingly, the Province has provided a promoter certificate in this prospectus.

The net proceeds to the Province from this offering will be approximately $1,635,949,200 after deducting the Underwriters' Fee (assuming that 70% of the common shares offered under this prospectus are sold to institutional investors) but before deducting the expenses of this offering ($1,800,351,000 if the Over-Allotment Option is exercised in full). Immediately following the closing of this offering, and the other transactions described in "Principal and Selling Shareholder – Share Purchase Arrangements with the Province", the Province will hold between 507,813,684 and 508,393,333 common shares (between 499,663,684 and 500,243,333 common shares if the Over-Allotment Option is exercised in full), representing approximately 85% of Hydro One Limited's total issued and outstanding common shares (approximately 84% if the Over-Allotment Option is exercised in full) and 16,720,000 Series 1 preferred shares, representing 100% of the total issued and outstanding Series 1 preferred shares of Hydro One Limited. See "Principal and Selling Shareholder" and "Governance and Relationship with Principal Shareholder".

LEGAL PROCEEDINGS AND REGULATORY MATTERS

The Company is from time to time involved in legal proceedings of a nature considered normal to its business. Except as disclosed below, Hydro One believes that none of the litigation in which it is currently involved, or has been involved since the beginning of the most recently completed financial year, individually or in the aggregate, is material to its consolidated financial condition or results of operations.

In connection with the reorganization of Ontario Hydro, Hydro One Inc. succeeded Ontario Hydro as a party to various pending legal proceedings relating to the businesses, assets, real estate and employees transferred to it. Hydro One Inc. also assumed responsibility for future claims relating to the businesses, assets, real estate and employees acquired by Hydro One Inc. and arising out of events occurring prior to, as well as after, April 1, 1999. In addition to claims assumed by the Company, it is, from time to time, named as a defendant in legal actions arising in the normal course of business. There are currently no actions that are outstanding which are expected to have a material adverse effect on the Company.

LEGAL MATTERS

Certain legal matters in connection with this offering will be passed upon by Osler, Hoskin & Harcourt LLP on behalf of Hydro One Limited, by Torys LLP on behalf of the Selling Shareholder and by Blake, Cassels & Graydon LLP on behalf of the Underwriters. The partners and associates of each of Osler, Hoskin & Harcourt LLP, Torys LLP and Blake, Cassels & Graydon LLP beneficially own, directly or indirectly, less than one percent of the securities of Hydro One Limited or any associate or affiliate of Hydro One Limited.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as noted below and elsewhere in this prospectus, there are no material interests, direct or indirect, of any director or executive officer of the Company, any shareholder that beneficially owns, or controls or directs (directly or indirectly), more than 10% of any class or series of Hydro One Limited's outstanding voting securities, or any associate or affiliate of any of the foregoing persons, in any transaction within the three years before the date hereof that has materially affected or is reasonably expected to materially affect the Company.

Relationships with the Province and Other Parties

Overview

The Province will be Hydro One Limited's principal shareholder. The Ontario Energy Board is the principal regulator of Ontario's electricity industry. The Province appoints the board members of the Ontario Energy Board and fills any vacancies on the Ontario Energy Board. The Ontario Energy Board is obligated to implement approved directives of the Province concerning general policy and objectives to be pursued by the Ontario Energy Board and other directives aimed at addressing existing or potential abuses of market power by industry participants. The IESO, among other matters, directs the operation of the Ontario power system by balancing supply and demand of electricity and directing electricity flow and assumed the responsibility for forecasting supply and demand of electricity over the medium and long term to meet the needs of the province. The board of directors of the IESO, other than its Chief Executive Officer, is appointed by the Province in accordance with the regulations in effect from time to time under the Electricity Act.

Transfer Orders

The transfer orders pursuant to which Hydro One Inc. acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999, did not transfer certain assets, rights, liabilities or obligations where the transfer would constitute a breach of the terms of any such asset, right, liability or obligation or a breach of any law or order. The transfer orders also did not transfer title to some assets located on Reserves. See "Risk Factors – Risk from Transfer of Assets Located on Reserves".

Hydro One is obligated under the transfer orders to manage both the assets held in trust until it has obtained all consents necessary to complete the transfer of title to these assets to Hydro One and the assets otherwise retained by the Ontario Electricity Financial Corporation that relate to Hydro One's businesses. Hydro One has entered into an agreement with the Ontario Electricity Financial Corporation under which it is obligated, in managing these assets, to take instructions from the Ontario Electricity Financial Corporation if Hydro One's actions could have a material adverse effect on the Ontario Electricity Financial Corporation. The Ontario Electricity Financial Corporation has retained the right to take control of and manage the assets, although it must notify and consult with Hydro One before doing so and must exercise its powers relating to the assets in a manner that will facilitate the operation of Hydro One's businesses. The consent of the Ontario Electricity Financial Corporation is also required prior to any disposition of these assets.

The Province also transferred officers, employees, assets, liabilities, rights and obligations of Ontario Hydro in a similar manner to its other successor transferees. These transfer orders include a dispute resolution mechanism to resolve any disagreement among the various transferees with respect to the transfer of specific assets, liabilities, rights or obligations.

The transfer orders do not contain any representations or warranties from the Province or the Ontario Electricity Financial Corporation with respect to the transferred officers, employees, assets, liabilities, rights and obligations. Furthermore, under the Electricity Act, the Ontario Electricity Financial Corporation was released from liability in respect of all assets and liabilities transferred by the transfer orders, except for liability under Hydro One's indemnity from the Ontario Electricity Financial Corporation. See "Governance and Relationship with Principal Shareholder – Ontario Electricity Financial Corporation Indemnity". By the terms of the transfer orders, each transferee indemnifies the Ontario Electricity Financial Corporation with respect to any assets and liabilities related to that transferee's business not effectively transferred, and is obligated to take all reasonable measures to complete the transfers where the transfers were not effective.

Hydro One has indemnified the Ontario Electricity Financial Corporation in respect of the damages, losses, obligations, liabilities, claims, encumbrances, penalties, interest, taxes, deficiencies, costs and expenses arising from matters relating to the Company's business and any failure by Hydro One to comply with its obligations to the Ontario Electricity Financial Corporation under agreements dated as of April 1, 1999. These obligations include obligations to employ the employees transferred to Hydro One under the transfer orders, make and remit employee source deductions (including tax withholding amounts, and employer contributions), manage the real and personal properties which the Ontario Electricity Financial Corporation continues to hold in trust or otherwise and take any necessary action to transfer all of these properties to the Company, to pay realty taxes and other costs, provide access to books and records and to assume other responsibilities in respect of the assets held by the Ontario Electricity Financial Corporation in trust for the Company.

AUDITORS, TRANSFER AGENT AND REGISTRAR

KPMG LLP, Chartered Professional Accountants, Licensed Public Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario, M5H 2S5, is the auditor of Hydro One Limited and Hydro One Inc. and has confirmed that it is independent of Hydro One Limited and Hydro One Inc. within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

The transfer agent and registrar for Hydro One Limited's common shares will be Computershare Investor Services Inc. at its principal office in Toronto, Ontario.

MATERIAL CONTRACTS

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which Hydro One Limited has entered into since the beginning of the last financial year before the date of this prospectus, entered into prior to such date but which contract is still in effect, or to which Hydro One Limited is or will become a party on or prior to the closing of this offering:

(a) the Underwriting Agreement, described under "Plan of Distribution";

(b) the Governance Agreement, described under "Governance and Relationship with Principal Shareholder"; and

(c) the Registration Rights Agreement, described under "Governance and Relationship with Principal Shareholder".

Copies of the foregoing material agreements, once executed, will be filed with the Canadian securities regulatory authorities and available on SEDAR at www.sedar.com. Prospective purchasers are encouraged to read the full text of such material agreements.

PURCHASERS' STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces and territories of Canada, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limits prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

Certain remedies, including statutory rights for rescission or damages, may not be available against the Province of Ontario as selling shareholder or as a promoter of Hydro One Limited. See "Risk Factors – Risks Relating to the Company's Relationship with the Province – Potential Difficulties in Enforcing Civil Liabilities Against the Province, Hydro One Limited and Other Persons". The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

EXEMPTIONS

Hydro One Inc. applied to the Ontario Securities Commission, as principal regulator, for a decision exempting Hydro One Limited from the requirements in section 3.2 of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* which requires financial statements to be prepared in accordance with and disclosed in compliance with International Financial Reporting Standards. On August 27, 2015, the exemption was granted. The decision granting the exemption permits Hydro One Limited to prepare and present its financial statements required to be filed with the securities regulatory authorities in each of the provinces and territories of Canada (including financial statements included in any prospectus of Hydro One Limited) in accordance with U.S. GAAP until the earliest to occur of the following:

(a) if Hydro One Limited does not complete the pre-closing reorganization and this offering in the manner described in the decision granting the exemption;

(b) January 1, 2019;

(c) if, after all of the outstanding shares of Hydro One Inc. are acquired by Hydro One Limited, Hydro One Limited ceases to have activities subject to rate regulation, the first day of Hydro One Limited's financial year commencing after its ceases to have such activities subject to rate regulation; and

(d) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

The exemptive relief was requested: (i) due to continuing uncertainty of accounting treatment and lack of a specific mandatory standard for entities with activities subject to rate regulation under International Financial Reporting Standards; (ii) because U.S. GAAP provides a more suitable set of accounting principles for entities with activities subject to rate regulation and is more consistent with those prescribed by the Ontario Energy Board in its Accounting Procedures Handbook for Electric Distribution Utilities; and (iii) to ensure consistency with and comparability to the financial statements of Hydro One Inc. which reports in U.S. GAAP, as well as Hydro One Limited's industry peers that currently report in U.S. GAAP.

Hydro One Limited has applied to the Ontario Securities Commission, as principal regulator, for exemptive relief from item 32.1(1)(b) of Form 41-101F1 as prescribed under National Instrument 41-101 – *General Prospectus Requirements* with respect to certain historical financial statements relating to Haldimand Hydro, Norfolk Power and Woodstock Hydro (collectively, the "**Non-Significant Acquisitions**"), which Hydro One Limited understands may be considered a primary business of the issuer pursuant to item 32.1(1)(b) of Form 41-101F1. The treatment of the acquired businesses as a primary business of the issuer would require Hydro One Limited to include in the prospectus audited financial statements for such businesses for the three completed financial years prior to the date of the prospectus, together with interim financial statements for the relevant interim periods. Hydro One Limited has applied for exemptive relief from the requirement to include audited financial statements relating to the Non-Significant Acquisitions for the three completed financial years prior to the date of the prospectus and interim financial statements relating to the Non-Significant Acquisitions for the relevant interim periods. The exemptions requested will be evidenced by the issuance of a receipt for this prospectus. In its application, Hydro One Limited made, among others, the following submissions:

- The Non-Significant Acquisitions are not significant or otherwise material having regard to the overall size and value of the Company's business and operations. Including the financial statements and related management's discussion and analysis disclosure with respect to the Non-Significant Acquisitions would be confusing to investors and would not add any additional meaningful disclosure.

- The historical financial statements of Hydro One Inc. are the more appropriate financial statements for the purposes of allowing investors to form a reasonable judgment regarding the Company and the securities offered under this prospectus.

- Haldimand Hydro and Norfolk Power were acquired, and Woodstock Hydro will be acquired, by Hydro One Inc., which is a reporting issuer. No financial statement disclosure was required to be provided by Hydro One Inc. for those businesses under the significant acquisition provisions of applicable securities laws. Further, if

Hydro One Inc. had been the issuer in this offering, it would not have been subject to the requirement to provide financial statements for the three businesses by virtue of item 32.1(2) of Form 41-101F1.

- Based on the foregoing, Hydro One Limited does not believe that the financial statements in respect of which the relief was requested are necessary for the prospectus to contain full, true and plain disclosure of all material facts with respect to the common shares.

AGENT FOR SERVICE OF PROCESS IN CANADA

Kathryn Jackson, a director of Hydro One Limited, resides outside of Canada. Ms. Jackson has appointed Hydro One Limited, 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5, Canada, as agent for service of process in Canada. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process.

GLOSSARY

"**$**" or "**dollar**" means Canadian Dollars.

"**1933 Act**" means the *United States Securities Act of 1933*, as amended.

"**allowable capital loss**" has the meaning given to such term set out under "Certain Canadian Federal Income Tax Considerations – Taxation of Holders of Common Shares – Dispositions".

"**Board**" means the Board of Directors of Hydro One Limited.

"**BPSAA**" has the meaning given to such term set out under "Executive Compensation – Components of Compensation – Transitional Arrangements".

"**BPSECA**" has the meaning given to such term set out under "Executive Compensation – Components of Compensation – Transitional Arrangements".

"**CAGR**" means compound annual growth rate.

"**CDM**" means conservation and demand management.

"**Closing Date**" has the meaning given to such term set out on the cover page of this prospectus.

"**Code of Conduct**" has the meaning given to such term set out under "Directors and Management of the Company – Ethical Business Conduct".

"**common shares**" has the meaning given to such term set out on the cover page of this prospectus.

"**Corporate Governance Guidelines**" has the meaning given to such term set out under "Directors and Management of the Company – Board Renewal".

"**Council**" means the Premier's Advisory Council on Government Assets.

"**demand registration**" has the meaning given to such term set out under "Governance and Relationship with Principal Shareholder – Province's Ownership of Common Shares and Preferred Shares – Registration Rights Agreement".

"**Diversity Policy**" has the meaning given to such term set out under "Directors and Management of the Company – Diversity".

"**DSU**" has the meaning given to such term set out under "Executive Compensation – Long Term Incentive Plan – Authorized Shares".

"**Election Meeting**" has the meaning given to such term set out under "Directors and Management of the Company – Majority Voting Policy".

"**Electricity Act**" has the meaning given to such term set out under "Electricity Industry – Ontario's Electricity Industry – Evolution".

"**EPSCA**" means the Electrical Power Sector Construction Association.

"**FSIA**" means the *United States Foreign Sovereign Immunities Act of 1976*.

"**Governance Agreement**" means the governance agreement to be entered into as of the Closing Date between Hydro One Limited and the Province.

"**Grant Date**" has the meaning given to such term set out under "Share Grant Plans".

"**GWh**" means gigawatt-hours.

"**Haldimand Hydro**" means Haldimand County Utilities Inc.

"**Holder**" has the meaning given to such term set out under "Certain Canadian Federal Income Tax Considerations".

"**Hugessen**" has the meaning given to such term set out under "Executive Compensation – Compensation Consultant".

"**Human Resources Committee**" has the meaning given to such term set out under "Executive Compensation – Compensation Governance – Human Resources Committee".

"**Hydro One**" or the "**Company**" refer to Hydro One Limited, Hydro One Inc. and their subsidiaries taken together as a whole as they will exist immediately following the time of closing of this offering and the related Pre-Closing Transactions.

"**Hydro One Defined Benefit Pension Plan**" has the meaning given to such term set out under "Executive Compensation – Pension Plan Benefits – Existing Pension Arrangements".

"**Hydro One Entitlements**" has the meaning given to such term set out under "Governance and Relationship with Principal Shareholder – Ontario Electricity Financial Corporation Indemnity".

"**IESO**" means the Independent Electricity System Operator.

"**kV**" means kilovolt.

"**kW**" means kilowatt.

"**kWh**" means kilowatt hour.

"**LDC**" has the meaning given to such term set out under "Electricity Industry – Ontario's Electricity Industry – Evolution".

"**Liquidity Facility**" has the meaning given to such term set out under "Pre-Closing Transactions – Hydro One Inc. Credit Facilities".

"**Long Term Incentive Plan**" or "**LTIP**" means Hydro One's Long Term Incentive Plan.

"**Majority Withheld Vote**" has the meaning given to such term set out under "Directors and Management of the Company – Majority Voting Policy".

"**management**" has the meaning given to such term set out under "Meaning of Certain References".

"**Market Rules**" means the rules made under section 32 of the Electricity Act that are administered by the IESO.

"**Micro FIT**" means the micro feed-in-tariff program of the IESO.

"**MW**" means megawatt.

"**NEOs**" has the meaning given to such term set out under "Executive Compensation – Compensation Discussion and Analysis".

"**NERC**" has the meaning given to such term set out under "Electricity Industry – Ontario's Electricity Industry – Evolution – IESO".

“**New Term Facility**” has the meaning given to such term set out under “Pre-Closing Transactions – Hydro One Inc. Credit Facilities”.

“**Norfolk Power**” means Norfolk Power Inc.

“**Non-Significant Acquisitions**” has the meaning given to such term set out under “Exemptions”.

“**NPCC**” means the Northeast Power Coordinating Council, Inc.

“**OBCA**” means the *Business Corporations Act* (Ontario).

“**Ombudsman’s Mandate**” has the meaning given to such term set out under “Governance and Relationship with Principal Shareholder – Ombudsman”.

“**Ontario**” or the “**province**” in lower case type refers to the Province of Ontario as a geographical area.

“**Operating Credit Facility**” has the meaning given to such term set out under “Pre-Closing Transactions – Hydro One Inc. Credit Facilities”.

“**Options**” has the meaning given to such term set out under “Executive Compensation – Components of Compensation – Variable Compensation – Long Term Incentives”.

“**Over-Allotment Option**” has the meaning given to such term set out on the cover page of this prospectus.

“**PCB**” means polychlorinated biphenyls.

“**PILs**” or “**payments in lieu of tax**” means payments in lieu of corporate income taxes.

“**Pre-Closing Steps**” has the meaning given to such term set out under “Pre-Closing Transactions – Pre-Closing Steps”.

“**Proposed Amendments**” has the meaning given to such term set out under “Certain Canadian Federal Income Tax Considerations”.

“**Province**” or the “**Selling Shareholder**” has the meaning given to such term set out on the cover page of this prospectus.

“**PSUs**” has the meaning given to such term set out under “Executive Compensation – Components of Compensation – Variable Compensation – Long Term Incentives”.

“**PWU Share Grant Plan**” has the meaning given to such term set out under “Share Grant Plans”.

“**PWU Trusts**” has the meaning given to such term set out under “Pre-Closing Transactions – Share Purchase Arrangements with the Province”.

“**Registration Rights Agreement**” means the registration rights agreement to be entered into as of the Closing Date between Hydro One Limited and the Province.

“**Reserve**” means a “reserve” as that term is defined in the *Indian Act* (Canada).

“**RRFE**” has the meaning given to such term set out under “Business of Hydro One – Distribution Business – Regulation – Distribution Rates”.

“**RRIF**” has the meaning given to such term set out under “Eligibility for Investment”.

“**RRSP**” has the meaning given to such term set out under “Eligibility for Investment”.

"**RSUs**" has the meaning given to such term set out under "Executive Compensation – Components of Compensation – Variable Compensation – Long Term Incentives".

"**SAR**" has the meaning given to such term set out under "Executive Compensation – Long Term Incentive Plan – Authorized Shares".

"**SEC**" means the United States Securities and Exchange Commission.

"**Share Ownership Restrictions**" has the meaning given to such term set out under "Governance and Relationship with Principal Shareholder – 10% Ownership Restriction".

"**shares**" has the meaning given to such term set out under "Governance and Relationship with Principal Shareholder – Province's Ownership of Common Shares and Preferred Shares – Registration Rights Agreement".

"**Short Term Incentive Plan**" or "**STIP**" has the meaning given to such term set out under "Executive Compensation – Components of Compensation – Variable Compensation – Short Term Incentives".

"**Small FIT**" means the small feed-in-tariff program of the IESO.

"**Smaller Subgroup S&P/TSX60**" has the meaning given to such term set out under "Executive Compensation – Benchmarking and Pay Positioning for New Chief Executive Officer and New Chief Financial Officer"

"**Society Share Grant Plan**" has the meaning given to such term set out under "Share Grant Plans".

"**Society Trusts**" has the meaning given to such term set out under "Pre-Closing Transactions – Province's Share Purchase Arrangements".

"**Special Board Resolution**" has the meaning given to such term set out under "Governance and Relationship with Principal Shareholder – Governance Agreement – Board Approvals Requiring a Special Resolution of the Directors – Annual Confirmation of Chair and Chief Executive Officer".

"**Specified Provincial Entity**" means (1)(a) the Ontario Financing Authority, (b) the IESO, (c) Ontario Power Generation Inc., (d) the Electrical Safety Authority, (e) Ontario Electricity Financial Corporation, (f) Infrastructure Ontario, or (g) a subsidiary of, or a person controlled by, any organization listed in (a) to (f); and (2) the Ontario Energy Board.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**taxable capital gain**" has the meaning given to such term set out under "Certain Canadian Federal Income Tax Considerations – Taxation of Holders of Common Shares – Dispositions".

"**TFSA**" has the meaning given to such term set out under "Eligibility for Investment".

"**Trusts**" has the meaning given to such term set out under "Pre-Closing Transactions – Share Purchase Arrangements with the Province".

"**TSX**" has the meaning given to such term set out on the cover page of this prospectus.

"**TWh**" means terawatt-hours.

"**UMIR**" means the Universal Market Integrity Rules for Canadian Marketplaces.

"**Underwriters**" has the meaning given to such term set out on the cover page of this prospectus.

“**Underwriters’ Fee**” has the meaning given to such term set out on the cover page of this prospectus.

“**Underwriting Agreement**” has the meaning given to such term set out under “Plan of Distribution”.

“**U.S.**” means United States of America.

“**U.S.$**” means U.S. dollars.

“**U.S. GAAP**” means United States Generally Accepted Accounting Principles.

“**Voting Securities**” means a security of Hydro One Limited carrying a voting right either under all circumstances or under some circumstances that have occurred and are continuing.

“**Woodstock Hydro**” means Woodstock Hydro Holdings Inc.

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HYDRO ONE LIMITED

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Hydro One Limited

We have audited the accompanying financial statements of Hydro One Limited, which comprise the balance sheet as at August 31, 2015, statements of changes in equity and cash flows for the one day period ended August 31, 2015 and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with United States Generally Accepted Accounting Principles, 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 audit. We conducted our audit 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 and fair presentation 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 audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Hydro One Limited financial statements present fairly, in all material respects, the financial position of Hydro One Limited as at August 31, 2015 and its results of operations and its cash flows for the one day period ended August 31, 2015 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
October 28, 2015

HYDRO ONE LIMITED

BALANCE SHEET
At August 31, 2015
(Canadian dollars)

Assets:	
Cash and cash equivalents	100,000
Total assets	**100,000**
Subsequent Events (Note 4)	
Shareholder's equity:	
Share capital (authorized: unlimited; issued: 100,000) *(Note 3)*	100,000
Total shareholder's equity	**100,000**

On behalf of the Board of Directors:

(Signed) DAVID DENISON
Director

(Signed) PHILIP ORSINO
Director

See accompanying notes to Financial Statements.

HYDRO ONE LIMITED

STATEMENT OF CHANGES IN EQUITY
One day period ended August 31, 2015
(Canadian dollars)

Shareholder's equity – beginning of period	—
Common shares issued	100,000
Shareholder's equity – end of period	**100,000**

See accompanying notes to Financial Statements.

HYDRO ONE LIMITED

STATEMENT OF CASH FLOWS
One day period ended August 31, 2015
(Canadian dollars)

Financing activity	
Proceeds from common shares issued	100,000
Increase in cash	100,000
Cash – beginning of period	—
Cash – end of period	**100,000**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company), was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario) and issued 100,000 common shares to the Province of Ontario (the Province) on that date. The Company was formed for the purpose of completing a public offering of its common shares.

The Company's registered and head offices are located at 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario M5G 2P5.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Hydro One performed an evaluation of subsequent events through to October 28, 2015, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 4 – Subsequent Events.

Cash

Cash consists of cash on hand.

3. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. The Company has 100,000 issued and outstanding common shares.

4. SUBSEQUENT EVENTS

Equity Compensation Plans

On October 8, 2015 the Company adopted two share grant plans, one for the benefit of employees represented by the Power Workers' Union (the PWU Plan) and one for the benefit of The Society of Energy Professionals (the Society Plan, and together with the PWU Plan, the Plans). The Plans provide for the issuance of common shares to certain employees represented by these unions for up to a twelve year period commencing April 1, 2017 for the PWU Plan and commencing April 1, 2018 for the Society Plan.

Public Offering

The Company filed a final prospectus by way of a secondary offering on October 28, 2015 for the sale to the public of 81,100,000 common shares held by the Province, subject to the terms of an underwriting agreement. The underwriters of the Public Offering will be granted an over-allotment option, exercisable, in whole or in part, at the sole discretion of the underwriters, for a period of 30 days from the closing of the Public Offering, to purchase up to an additional 8,150,000 common shares. Immediately following the closing of the Public Offering and the other transactions contemplated therein, the Company will have 595,000,000 common shares issued and outstanding. The Company will not receive any proceeds from this Public Offering.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three and six months ended June 30, 2015 and 2014

(millions of Canadian dollars, except per share amounts)	Three months ended June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Revenues				
Distribution (includes related party revenues of $40 (2014 – $40) and $80 (2014 – $80) for three and six months ended June 30, respectively) *(Note 14)*	1,185	1,170	2,574	2,497
Transmission (includes related party revenues of $364 (2014 – $371) and $770 (2014 – $782) for three and six months ended June 30, respectively) *(Note 14)*	364	382	770	804
Other	14	14	27	29
	1,563	1,566	3,371	3,330
Costs				
Purchased power (includes related party costs of $475 (2014 – $574) and $1,274 (2014 – $1,368) for three and six months ended June 30, respectively) *(Note 14)*	838	824	1,808	1,746
Operation, maintenance and administration *(Note 14)*	282	334	560	645
Depreciation and amortization	190	181	377	348
	1,310	1,339	2,745	2,739
Income before financing charges and provision for payments in lieu of corporate income taxes	253	227	626	591
Financing charges	93	95	187	185
Income before provision for payments in lieu of corporate income taxes	160	132	439	406
Provision for payments in lieu of corporate income taxes *(Notes 5, 14)*	23	17	68	51
Net income	137	115	371	355
Net income attributable to noncontrolling interest *(Note 13)*	1	–	3	–
Net income attributable to Shareholder of Hydro One Inc.	**136**	**115**	**368**	**355**
Other comprehensive income	–	–	–	–
Comprehensive income	**137**	**115**	**371**	**355**
Comprehensive income attributable to noncontrolling interest *(Note 13)*	1	–	3	–
Comprehensive income attributable to Shareholder of Hydro One Inc.	**136**	**115**	**368**	**355**
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 11)*	1,308	1,099	3,594	3,456
Dividends per common share declared *(Canadian dollars) (Note 12)*	250	250	500	2,196

See accompanying notes to Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)
At June 30, 2015 and December 31, 2014

(millions of Canadian dollars)	**June 30, 2015**	**December 31, 2014**
Assets		
Current assets:		
Cash and cash equivalents *(Note 8)*	270	100
Accounts receivable (net of allowance for doubtful accounts – \$76; 2014 – \$66) *(Note 6)*	1,013	1,016
Due from related parties *(Note 14)*	177	224
Regulatory assets	43	31
Materials and supplies	26	23
Deferred income tax assets	19	19
Derivative instruments *(Note 8)*	1	2
Prepaid expenses and other assets	35	35
	1,584	1,450
Property, plant and equipment:		
Property, plant and equipment in service	25,886	25,356
Less: accumulated depreciation	9,398	9,134
	16,488	16,222
Construction in progress	1,258	1,025
Future use land, components and spares	161	154
	17,907	17,401
Other long-term assets:		
Regulatory assets	3,170	3,200
Intangible assets (net of accumulated amortization – \$331; 2014 – \$305)	258	276
Goodwill *(Note 4)*	199	173
Deferred debt issuance costs	36	36
Deferred income tax assets	6	7
Other	7	7
	3,676	3,699
Total assets	**23,167**	**22,550**

See accompanying notes to Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)
At June 30, 2015 and December 31, 2014

(millions of Canadian dollars, except number of shares)	**June 30, 2015**	**December 31, 2014**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 8)*	–	2
Accounts payable	184	173
Accrued liabilities *(Notes 9, 10)*	639	611
Due to related parties *(Note 14)*	52	227
Accrued interest	99	100
Regulatory liabilities	18	47
Derivative instruments *(Note 8)*	3	3
Long-term debt payable within one year (includes $251 measured at fair value; 2014 – $252) *(Notes 7, 8)*	1,017	552
	2,012	1,715
Long-term debt (includes $50 measured at fair value; 2014 – nil) *(Notes 7, 8)*	8,273	8,373
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 9)*	1,569	1,533
Deferred income tax liabilities	1,380	1,313
Pension benefit liability *(Note 9)*	1,228	1,236
Environmental liabilities *(Note 10)*	207	221
Regulatory liabilities	200	168
Net unamortized debt premiums	18	18
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	14	17
	4,625	4,515
Total liabilities	**14,910**	**14,603**
Contingencies and Commitments (Notes 16, 17)		
Subsequent Events (Note 19)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 11, 12)*	323	323
Noncontrolling interest subject to redemption *(Note 13)*	21	21
Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 11, 12)*	3,314	3,314
Retained earnings	4,558	4,249
Accumulated other comprehensive loss	(9)	(9)
Noncontrolling interest *(Note 13)*	50	49
Total equity	**7,913**	**7,603**
	23,167	**22,550**

See accompanying notes to Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the six months ended June 30, 2015 and 2014

Six months ended June 30, 2015 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest *(Note 13)*	Total Equity
January 1, 2015	3,314	4,249	(9)	49	7,603
Net income	–	368	–	2	370
Other comprehensive income	–	–	–	–	–
Distributions to noncontrolling interest	–	–	–	(1)	(1)
Dividends on preferred shares	–	(9)	–	–	(9)
Dividends on common shares	–	(50)	–	–	(50)
June 30, 2015	3,314	4,558	(9)	50	7,913

Six months ended June 30, 2014 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
January 1, 2014	3,314	3,787	(9)	–	7,092
Net income	–	355	–	–	355
Other comprehensive income	–	–	–	–	–
Dividends on preferred shares	–	(9)	–	–	(9)
Dividends on common shares	–	(220)	–	–	(220)
June 30, 2014	3,314	3,913	(9)	–	7,218

See accompanying notes to Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and six months ended June 30, 2015 and 2014

(millions of Canadian dollars)	Three months ended June 30 **2015**	Three months ended June 30 **2014**	Six months ended June 30 **2015**	Six months ended June 30 **2014**
Operating activities				
Net income	137	115	371	355
Environmental expenditures	(5)	(4)	(9)	(7)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	162	155	332	306
Regulatory assets and liabilities	(16)	(89)	72	(26)
Deferred income taxes	1	2	3	8
Other	1	2	3	2
Changes in non-cash balances related to operations *(Note 15)*	7	4	(59)	(304)
Net cash from operating activities	287	185	713	334
Financing activities				
Long-term debt issued	350	453	350	628
Dividends paid	(30)	(30)	(59)	(229)
Distributions paid to noncontrolling interest	(2)	–	(2)	–
Change in bank indebtedness	(35)	20	(2)	4
Other	(1)	(2)	(1)	(3)
Net cash from financing activities	282	441	286	400
Investing activities				
Capital expenditures *(Note 15)*				
Property, plant and equipment	(418)	(357)	(757)	(644)
Intangible assets	(4)	(10)	(9)	(15)
Net cash paid for Haldimand Hydro	(58)	–	(58)	–
Other	–	(1)	(5)	(1)
Net cash used in investing activities	(480)	(368)	(829)	(660)
Net change in cash and cash equivalents	89	258	170	74
Cash and cash equivalents, beginning of period	181	381	100	565
Cash and cash equivalents, end of period	**270**	**639**	**270**	**639**

See accompanying notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. The electricity rates of these businesses are regulated by the Ontario Energy Board (OEB).

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited interim Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries, including Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Lake Erie Link Management Inc., Municipal Billing Services Inc. (previously Hydro One Lake Erie Link Company Inc.), Norfolk Power Distribution Inc. (NPDI), Norfolk Energy Inc. and Hydro One B2M Holdings Inc. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These unaudited interim Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These unaudited interim Consolidated Financial Statements do not contain all disclosures required by US GAAP for annual audited consolidated financial statements. Accordingly, they should be read in conjunction with the Company's annual Consolidated Financial Statements as at, and for the year ended December 31, 2014. In particular, the Company's significant accounting policies are presented in Note 2 to the annual Consolidated Financial Statements and have been applied consistently in the preparation of these unaudited interim Consolidated Financial Statements. In the opinion of management, these unaudited interim Consolidated Financial Statements include all adjustments that are necessary to fairly state the financial position and results of operations of Hydro One as at, and for the three and six months ended June 30, 2015. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim periods or for the year ending December 31, 2015.

Hydro One performed an evaluation of subsequent events through to August 11, 2015, the date these unaudited interim Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these unaudited interim Consolidated Financial Statements. See Note 19 – Subsequent Events.

Rate Setting

The Company's Transmission Business includes the transmission business of Hydro One Networks, as well as its ownership interest in B2M Limited Partnership (B2M LP). The Company's consolidated Distribution Business includes the distribution business of Hydro One Networks, as well as the subsidiaries Hydro One Brampton, Hydro One Remote Communities, and NPDI.

Transmission

On September 16, 2014, Hydro One Networks filed an application with the OEB for 2015 and 2016 transmission rates. On January 8, 2015, the OEB approved the 2015 Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, of $1,477 million and the 2016 revenue requirement of $1,516 million, subject to adjustments for the cost of capital parameters.

On October 24, 2014, B2M LP filed an application with the OEB for an interim transmission rate, seeking approval for a revenue requirement of $42 million in 2015. The interim Rate Order was approved by the OEB on December 11, 2014. On March 30, 2015, B2M LP filed a full cost-of-service application for 2015-2019 transmission rates. In its application, B2M LP is seeking approval of a revenue requirement of $43 million for 2015, $45 million for 2016, $46 million for 2017, $47 million for 2018, and $47 million for 2019.

On June 30, 2015, B2M LP was re-financed with debt bearing interest at a lower coupon rate. This has lowered the B2M LP revenue requirement. As a result of the reduced cost of debt, B2M LP's requested revenue requirement was amended to $39 million for 2015, $36 million for 2016, $37 million for 2017, $38 million for 2018, and $37 million for 2019. As part of its application, B2M LP is seeking the recovery of its initial start-up costs totalling $8 million over the 2016 to 2019 test years at a rate of $2 million per year.

Distribution

On December 19, 2013, Hydro One Networks filed a 2015-2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. On December 18, 2014, the OEB issued a Decision and interim Rate Order approving the 2014 distribution rates as interim 2015 rates effective January 1, 2015. On March 12, 2015, the OEB issued a Decision and Rate Order approving a revenue requirement of $1,326 million for 2015, $1,435 million for 2016 and $1,491 million for 2017. The rates for 2015 are effective on May 1, 2015, and are retroactive to January 1, 2015. The rates for 2016 and 2017 are estimates that may change based on 2016 and 2017 Rate Orders. On April 23, 2015, the Final Rate Order was approved by the OEB.

On April 23, 2014, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2015 distribution rates. The 2015 distribution rate application was seeking the approval of a revenue requirement of approximately $74 million for 2015. In its application, Hydro One Brampton Networks also requested OEB approval for retail transmission service rates and the approval of rate riders to dispose of certain deferral and variance accounts. On December 18, 2014, the OEB approved a revenue requirement of $72 million. On January 15, 2015, the OEB issued its final Rate Order approving the application.

On September 24, 2014, Hydro One Remote Communities filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7%. On March 19, 2015, the OEB approved an increase of approximately 1.6% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2015.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the company's consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of ASU 2015-02 on its consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-04, Compensation – Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets. This ASU permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of ASU 2015-05 on its consolidated financial statements.

4. BUSINESS COMBINATIONS

Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired 100% of the common shares of Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution company located in southwestern Ontario. The total purchase price for Haldimand Hydro is approximately $65 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed recognized at the acquisition date:

(millions of Canadian dollars)	
Cash and cash equivalents	5
Working capital	4
Property, plant and equipment	48
Deferred income tax assets	1
Goodwill	26
Long-term debt	(16)
Regulatory liabilities	(3)
	65

The preliminary determination of the fair value of assets acquired and liabilities assumed has been based upon the most recent available information for Haldimand Hydro, management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

The Company has not yet completed the final fair value measurements as at June 30, 2015. In addition, the purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been determined. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and the fair values of the assets acquired and liabilities assumed. The actual total purchase price and the fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. None of the goodwill recognized is expected to be deductible for income tax purposes.

All costs related to the acquisition have been expensed through the consolidated statements of operations and comprehensive income. The disclosure of Haldimand Hydro's pro forma information has been deemed immaterial to the Company's consolidated financial results for the three and six months ended June 30, 2015.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for working capital and other closing adjustments, was approximately $68 million. The purchase agreement provided for final purchase price adjustments based on agreed working capital and other balances at the acquisition date. The purchase price has been finalized during the six months ended June 30, 2015, with no adjustments to the preliminary purchase price allocation as disclosed at December 31, 2014.

Woodstock Hydro Purchase Agreement

On May 21, 2014, Hydro One reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Woodstock Hydro will be approximately $29 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015.

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The current provision for payments in lieu of corporate income taxes (PILs) is remitted to, or received from, the Ontario Electricity Financial Corporation (OEFC). At June 30, 2015, $10 million due from the OEFC was included in due from related parties on the interim Consolidated Balance Sheet (December 31, 2014 – $39 million). The total provision for PILs using the liability method of accounting includes deferred income taxes that are not expected to be recovered from ratepayers. Deferred PILs balances expected to be recovered from ratepayers result in regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

For the six months ended June 30, 2015, the Company's overall effective tax rate of 15.49% differed from the enacted statutory rate of 26.50% primarily due to the temporary differences included in the rate-setting process, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed for accounting purposes, and interest deducted for tax purposes in excess of interest expensed for accounting purposes.

6. ACCOUNTS RECEIVABLE

(millions of Canadian dollars)	**June 30, 2015**	**December 31, 2014**
Accounts receivable – billed	498	496
Accounts receivable – unbilled	591	586
Accounts receivable, gross	1,089	1,082
Allowance for doubtful accounts	(76)	(66)
Accounts receivable, net	1,013	1,016

The following tables show the movements in the allowance for doubtful accounts for the six months ended June 30, 2015 and the year ended December 31, 2014:

Six months ended June 30, 2015 (millions of Canadian dollars)	
Allowance for doubtful accounts – January 1, 2015	(66)
Write-offs	18
Additions to allowance for doubtful accounts	(28)
Allowance for doubtful accounts – June 30, 2015	(76)

Year ended December 31, 2014 (millions of Canadian dollars)	
Allowance for doubtful accounts – January 1, 2014	(36)
Write-offs	24
Additions to allowance for doubtful accounts	(54)
Allowance for doubtful accounts – December 31, 2014	(66)

7. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1 billion. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at June 30, 2015 or December 31, 2014.

Hydro One has a $1.5 billion committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2020. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and supports the Company's Commercial Paper Program. The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3 billion. At June 30, 2015, $837 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at June 30, 2015 and December 31, 2014:

(millions of Canadian dollars)	**June 30, 2015**	**December 31, 2014**
Notes and debentures	9,289	8,923
Add: Unrealized mark-to-market loss[1]	1	2
Less: Long-term debt payable within one year	(1,017)	(552)
Long-term debt	8,273	8,373

[1] The unrealized mark-to-market loss relates to $250 million of the Series 21 notes due 2015. The unrealized mark-to-market loss is offset by a $1 million (December 31, 2014 – $2 million) unrealized mark-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 8 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

On April 30, 2015, Hydro One issued $350 million notes (MTN Series 33 notes) under its MTN Program, with a maturity date of April 30, 2020 and a coupon rate of 1.62%.

Long-term debt totalling $16 million was assumed by Hydro One as part of the Haldimand Hydro acquisition. It has been classified as current at June 30, 2015, and has been repaid in July 2015.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 8 – Fair Value of Financial Instruments and Risk Management.

8. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At June 30, 2015 and December 31, 2014, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at June 30, 2015 and December 31, 2014 are as follows:

	June 30, 2015		December 31, 2014	
(millions of Canadian dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt				
$250 million of MTN Series 21 notes[1]	251	251	252	252
$50 million of MTN Series 33 notes[1]	50	50	–	–
Other notes and debentures[2]	8,989	10,394	8,673	10,159
	9,290	10,695	8,925	10,411

[1] The fair value of $250 million of the MTN Series 21 notes and $50 million of the MTN Series 33 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of other notes and debentures, and the portions of the MTN Series 21 notes and the MTN Series 33 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At June 30, 2015, the Company had interest-rate swaps totalling $300 million (December 31, 2014 – $250 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to approximately 3% (December 31, 2014 – 3%) of its total long-term debt of $9,290 million (December 31, 2014 – $8,925 million). At June 30, 2015, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable rate debt; and

(b) a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt.

At June 30, 2015, the Company also had interest-rate swaps and forward rate agreements with a total notional value of $470 million (December 31, 2014 – $409 million) classified as undesignated contracts. The undesignated contracts consist of the following:

(c) a $150 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2014 to September 11, 2015;

(d) a $137 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on $137 million of the $228 million floating-rate MTN Series 31 notes from December 22, 2014 to December 21, 2015;

(e) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on $30 million of the $50 million floating-rate MTN Series 27 notes from March 3, 2015 to December 3, 2015;

(f) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 26, 2015 to July 24, 2015;

(g) a $20 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on $20 million of the $50 million floating-rate MTN Series 27 notes from June 3, 2015 to December 3, 2015;

(h) a $91 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on $91 million of the $228 million floating-rate MTN Series 31 notes from June 22, 2015 to December 21, 2015; and

(i) three interest-rate swaps with a total notional value of $12 million that were assumed as part of the Norfolk Power acquisition. These swaps consist of $8 million and $2 million floating-to-fixed interest-rate swap agreements maturing on September 20, 2029, and a $2 million floating-to-fixed interest-rate swap agreement maturing on September 20, 2019.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at June 30, 2015 and December 31, 2014 was as follows:

June 30, 2015 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	270	270	270	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	271	271	270	1	–
Liabilities:					
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	9,290	10,695	–	10,695	–
	9,293	10,698	–	10,698	–

December 31, 2014 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

Cash and cash equivalents include cash and short-term investments. At June 30, 2015, short-term investments consisted of bankers' acceptances and money market funds totalling $238 million (December 31, 2014 – $nil). The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the six months ended June 30, 2015 or the year ended December 31, 2014.

Risk Management

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 capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and six months ended June 30, 2015 and 2014 are included in financing charges as follows:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Unrealized loss (gain) on hedged debt	(1)	(3)	(1)	(5)
Unrealized loss (gain) on fair value interest-rate swaps	1	3	1	5
Net unrealized loss (gain)	–	–	–	–

At June 30, 2015, Hydro One had $300 million (December 31, 2014 – $250 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $1 million (December 31, 2014 – $2 million). During the six months ended June 30, 2015 and 2014, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At June 30, 2015 and December 31, 2014, 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, Hydro One did not earn a significant amount of revenue from any single customer. At June 30, 2015 and December 31, 2014, there was no significant accounts receivable balance due from any single customer.

At June 30, 2015, the Company's provision for bad debts was $76 million (December 31, 2014 – $66 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At June 30, 2015, approximately 7% of the Company's net accounts receivable were aged more than 60 days (December 31, 2014 – 6%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company'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. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the interim Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At June 30, 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $3 million (December 31, 2014 – $3 million). At June 30, 2015, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with five financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facility of $1,500 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At June 30, 2015, accounts payable and accrued liabilities in the amount of $823 million (December 31, 2014 – $784 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At June 30, 2015, Hydro One had issued long-term debt in the principal amount of $9,289 million (December 31, 2014 – $8,923 million). Principal repayments, total annual interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Long-term Debt Principal Repayments** *(millions of Canadian dollars)*	**Total Annual Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	1,016	416	3.6
2 years	50	387	1.4
3 years	600	371	5.2
4 years	978	344	2.4
5 years	650	331	2.9
	3,294	1,849	3.4
6 – 10 years	600	1,505	3.2
Over 10 years	5,395	4,227	5.4
	9,289	7,581	4.6

9. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Estimated 2015 annual pension plan contributions are approximately $174 million, based on an actuarial valuation as at December 31, 2013 and projected levels of 2015 pensionable earnings. Employer contributions of $89 million were paid during the six months ended June 30, 2015.

The following tables provide the components of the net periodic benefit costs for the three and six months ended June 30, 2015 and 2014:

	Pension Benefits		**Post-Retirement and Post-Employment Benefits**	
Three months ended June 30 (millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Current service cost, net of employee contributions	37	27	11	10
Interest cost	76	78	16	19
Expected return on plan assets, net of expenses[1]	(102)	(92)	–	–
Actuarial loss amortization	30	26	3	5
Net periodic benefit costs	41	39	30	34
Charged to results of operations[2]	22	22	14	15

Six months ended June 30 (millions of Canadian dollars)	Pension Benefits 2015	Pension Benefits 2014	Post-Retirement and Post-Employment Benefits 2015	Post-Retirement and Post-Employment Benefits 2014
Current service cost, net of employee contributions	74	55	22	20
Interest cost	152	156	32	38
Expected return on plan assets, net of expenses[1]	(204)	(184)	–	–
Actuarial loss amortization	60	52	6	10
Prior service cost amortization	–	–	–	1
Net periodic benefit costs	82	79	60	69
Charged to results of operations[2]	41	41	26	30

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2015 is 6.5% (2014 – 6.5%).

[2] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the three and six months ended June 30, 2015, pension benefit costs of $48 million (2014 – $47 million) and $90 million (2014 – $88 million), respectively, were attributed to labour, of which $22 million (2014 – $22 million) and $41 million (2014 – $41 million), respectively, were charged to operations, and $26 million (2014 – $25 million) and $49 million (2014 – $47 million), respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

10. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the six months ended June 30, 2015 and the year ended December 31, 2014:

Six months ended June 30, 2015 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	172	67	239
Interest accretion	4	1	5
Expenditures	(5)	(4)	(9)
Environmental liabilities, June 30	171	64	235
Less: current portion	16	12	28
	155	52	207

Year ended December 31, 2014 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

June 30, 2015 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	190	66	256
Less: discounting accumulated liabilities to present value	19	2	21
Discounted environmental liabilities	171	64	235

December 31, 2014 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

At June 30, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015[1]	9
2016	37
2017	36
2018	35
2019	33
Thereafter	106
	256

[1] The amounts disclosed represent amounts for the period from July 1, 2015 to December 31, 2015.

Hydro One records a liability for the estimated future expenditures for the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

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. 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 rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. In addition, with respect to the PCB environmental liability, 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.

At June 30, 2015, the Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $190 million (December 31, 2014 – $195 million). These expenditures are expected to be incurred over the period from 2015 to 2025.

At June 30, 2015, the Company's best estimate of the total estimated future expenditures to complete its LAR program is $66 million (December 31, 2014 – $70 million). These expenditures are expected to be incurred over the period from 2015 to 2023.

11. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of equity on the Consolidated Balance Sheets. No adjustment to the carrying value of the preferred shares has been recognized at June 30, 2015 and December 31, 2014. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and Shareholder expectations.

Earnings per Share

Basic and diluted earnings per share have been calculated on the basis of net income attributable to the Shareholder of Hydro One and the weighted average number of common shares outstanding during the year.

12. DIVIDENDS

During the three months ended June 30, 2015, preferred share dividends in the amount of $5 million (2014 – $5 million) and common share dividends in the amount of $25 million (2014 – $25 million) were declared.

During the six months ended June 30, 2015, preferred share dividends in the amount of $9 million (2014 – $9 million) and common share dividends in the amount of $50 million (2014 – $220 million) were declared.

13. NONCONTROLLING INTEREST

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest for the six months ended June 30, 2015 and the year ended December 31, 2014:

Six months ended June 30, 2015 (millions of Canadian dollars)	**Temporary equity**	**Equity**	**Total**
Noncontrolling interest – January 1, 2015	21	49	70
Distributions to noncontrolling interest	(1)	(1)	(2)
Net income attributable to noncontrolling interest	1	2	3
Noncontrolling interest – June 30, 2015	21	50	71

Year ended December 31, 2014 (millions of Canadian dollars)	**Temporary equity**	**Equity**	**Total**
Noncontrolling interest – January 1, 2014	–	–	–
Amount contributed by noncontrolling interest	22	50	72
Net income (loss) attributable to noncontrolling interest	(1)	(1)	(2)
Noncontrolling interest – December 31, 2014	21	49	70

14. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province. Effective January 1, 2015, the Ontario Power Authority (OPA) and IESO have merged and are now operating as IESO.

The Province

During the three and six months ended June 30, 2015, Hydro One paid dividends to the Province totalling $30 million (2014 – $30 million) and $59 million (2014 – $229 million), respectively.

IESO

During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $471 million (2014 – $568 million) and $1,262 million (2014 – $1,343 million), respectively, from the IESO-administered electricity market.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for the three and six months ended June 30, 2015 include $363 million (2014 – $368 million) and $768 million (2014 – $776 million), respectively, related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for the three and six months ended June 30, 2015 include $32 million (2014 – $32 million) and $64 million (2014 – $64 million), respectively, related to this program.

Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues for the three and six months ended June 30, 2015 include $8 million (2014 – $8 million) and $16 million (2014 – $16 million), respectively, related to these services.

The IESO (OPA prior to January 1, 2015) funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. During the three and six months ended June 30, 2015, Hydro One received $11 million (2014 – $14 million) and $23 million (2014 – $21 million), respectively, related to these programs.

OPG

During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $2 million (2014 – $4 million) and $8 million (2014 – $18 million), respectively, from OPG.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. During the three and six months ended June 30, 2015, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $1 million (2014 – $3 million) and $3 million (2014 – $6 million), respectively, primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were insignificant for the three months ended June 30, 2015 and 2014, and $1 million (2014 – $1 million) for the six months ended June 30, 2015.

OEFC

During the three and six months ended June 30, 2015, Hydro One made payments in lieu of corporate income taxes to the OEFC totalling $14 million (2014 – $21 million) and $32 million (2014 – $43 million), respectively.

During the three and six months ended June 30, 2015, Hydro One purchased power in the amount of $2 million (2014 – $2 million) and $4 million (2014 – $7 million), respectively, from power contracts administered by the OEFC.

During the six months ended June 30, 2015, Hydro One paid a $5 million (2014 – $5 million) annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

Payments in lieu of property taxes are paid to the OEFC.

OEB

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 transmitters. During the three and six months ended June 30, 2015, Hydro One incurred $3 million (2014 – $3 million) and $6 million (2014 – $6 million), respectively, in OEB fees.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

(millions of Canadian dollars)	**June 30, 2015**	**December 31, 2014**
Due from related parties	177	224
Due to related parties[1]	(52)	(227)

[1] Included in due to related parties at June 30, 2015 are amounts owing to the IESO in respect of power purchases of $41 million (December 31, 2014 – $214 million).

15. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Accounts receivable	100	76	15	(113)
Due from related parties	21	1	47	(9)
Materials and supplies	–	2	(1)	(1)
Prepaid expenses and other assets	(3)	4	(2)	(98)
Accounts payable	19	(13)	7	(15)
Accrued liabilities	(4)	47	18	44
Due to related parties	(130)	(106)	(175)	(152)
Accrued interest	(17)	(19)	(1)	1
Long-term accounts payable and other liabilities	1	(9)	(3)	(4)
Post-retirement and post-employment benefit liability	20	21	36	43
	7	4	(59)	(304)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in capitalized depreciation and the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Capital investments in property, plant and equipment	(425)	(373)	(765)	(665)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	7	16	8	21
Capital expenditures – property, plant and equipment	(418)	(357)	(757)	(644)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Capital investments in intangible assets	(4)	(7)	(9)	(11)
Net change in accruals included in capital investments in intangible assets	–	(3)	–	(4)
Capital expenditures – intangible assets	(4)	(10)	(9)	(15)

Supplementary Information

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	**2015**	**2014**	**2015**	**2014**
Net interest paid	122	121	207	202
PILs paid	14	21	32	43

16. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

17. COMMITMENTS

Outsourcing Agreements

Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018.

Brookfield Johnson Controls Canada LP (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at June 30, 2015, the Company provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $347 million (December 31, 2014 – $330 million), and on behalf of a distributor using guarantees of $1 million (December 31, 2014 – $1 million). In addition, as at June 30, 2015, the Company has provided letters of credit in the amount of $5 million (December 31, 2014 – $8 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At June 30, 2015, Hydro One had letters of credit of $126 million (December 31, 2014 – $126 million) outstanding relating to retirement compensation arrangements.

18. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, which includes certain corporate activities and the operations of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Three months ended June 30, 2015 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	364	1,185	14	1,563
Purchased power	–	838	–	838
Operation, maintenance and administration	98	168	16	282
Depreciation and amortization	94	94	2	190
Income (loss) before financing charges and provision for PILs	172	85	(4)	253
Capital investments	234	192	3	429

Three months ended June 30, 2014 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	382	1,170	14	1,566
Purchased power	–	824	–	824
Operation, maintenance and administration	105	214	15	334
Depreciation and amortization	88	91	2	181
Income (loss) before financing charges and provision for PILs	189	41	(3)	227
Capital investments	203	175	2	380

Six months ended June 30, 2015 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	770	2,574	27	3,371
Purchased power	–	1,808	–	1,808
Operation, maintenance and administration	197	334	29	560
Depreciation and amortization	188	186	3	377
Income (loss) before financing charges and provision for PILs	385	246	(5)	626
Capital investments	445	324	5	774

Six months ended June 30, 2014 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	804	2,497	29	3,330
Purchased power	–	1,746	–	1,746
Operation, maintenance and administration	220	395	30	645
Depreciation and amortization	169	175	4	348
Income (loss) before financing charges and provision for PILs	415	181	(5)	591
Capital investments	376	298	2	676

Total Assets by Segment:

(millions of Canadian dollars)	**June 30, 2015**	**December 31, 2014**
Transmission	12,822	12,540
Distribution	9,888	9,805
Other	457	205
Total assets	23,167	22,550

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

19. SUBSEQUENT EVENTS

Dividends

On August 11, 2015, preferred share dividends in the amount of $4 million and common share dividends in the amount of $25 million were declared.

Class Action Lawsuit

On July 22, 2015, two Toronto law firms issued a joint press release announcing that a $125 million lawsuit had been commenced in the Ontario Superior Court of Justice against Hydro One and four of its subsidiaries. The claim is proposed as a class action and alleges improper billing and account management practices. The claim has not been served on Hydro One nor has it been certified as a class action.

Power Workers' Union Agreement

On April 14, 2015, Hydro One reached a tentative agreement with the Power Workers' Union (PWU) for a renewal of the collective agreement. The agreement is for a three-year term, covering April 1, 2015 to March 31, 2018, subject to certain conditions. The agreement has been ratified by the PWU and the Hydro One Board of Directors in July 2015.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2015.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2014. The effectiveness of these internal controls is reported to the Audit, Finance and Pension Investment Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the Shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit, Finance and Pension Investment Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit, Finance and Pension Investment Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit, Finance and Pension Investment Committee, with and without the presence of management, to discuss their audit findings, if any.

The President and Chief Executive Officer and the Chief Financial Officer (Acting) have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One Inc.'s management:

Carmine Marcello
President and Chief Executive Officer

Ali R. Suleman

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated 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 Consolidated 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 Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated 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 Consolidated 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 Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2014 and December 31, 2013, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 11, 2015

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2014**	**2013**
Revenues		
Distribution (includes $159 related party revenues; 2013 – $160) *(Note 20)*	4,903	4,484
Transmission (includes $1,567 related party revenues; 2013 – $1,517) *(Note 20)*	1,588	1,529
Other	57	61
	6,548	6,074
Costs		
Purchased power (includes $2,633 related party costs; 2013 – $2,500) *(Note 20)*	3,419	3,020
Operation, maintenance and administration *(Note 20)*	1,192	1,106
Depreciation and amortization *(Note 5)*	722	676
	5,333	4,802
Income before financing charges and provision for payments in lieu of corporate income taxes	1,215	1,272
Financing charges *(Note 6)*	379	360
Income before provision for payments in lieu of corporate income taxes	836	912
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	89	109
Net income	747	803
Net income (loss) attributable to noncontrolling interest *(Note 4)*	(2)	–
Net income attributable to the Shareholder of Hydro One Inc.	**749**	**803**
Other comprehensive income	–	–
Comprehensive income	**747**	**803**
Comprehensive income (loss) attributable to noncontrolling interest *(Note 4)*	(2)	–
Comprehensive income attributable to the Shareholder of Hydro One Inc.	**749**	**803**
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	7,319	7,850
Dividends per common share declared *(dollars) (Note 19)*	2,696	2,000

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	100	565
Accounts receivable (net of allowance for doubtful accounts – \$66; 2013 – \$36) *(Note 8)*	1,016	923
Due from related parties *(Note 20)*	224	197
Regulatory assets *(Note 11)*	31	47
Materials and supplies	23	23
Deferred income tax assets *(Note 7)*	19	18
Derivative instruments *(Note 13)*	2	6
Investment *(Notes 13, 20)*	–	251
Prepaid expenses and other assets	35	28
	1,450	2,058
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	25,356	23,820
Less: accumulated depreciation	9,134	8,615
	16,222	15,205
Construction in progress	1,025	1,078
Future use land, components and spares	154	148
	17,401	16,431
Other long-term assets:		
Regulatory assets *(Note 11)*	3,200	2,636
Intangible assets (net of accumulated amortization – \$305; 2013 – \$252) *(Note 10)*	276	313
Goodwill *(Note 4)*	173	133
Deferred debt issuance costs	36	36
Deferred income tax assets *(Note 7)*	7	11
Derivative instruments *(Note 13)*	–	6
Other	7	1
	3,699	3,136
Total assets	**22,550**	**21,625**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars, except number of shares)	**2014**	**2013**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	2	31
Accounts payable	173	135
Accrued liabilities *(Notes 15, 16)*	611	654
Due to related parties *(Note 20)*	227	230
Accrued interest	100	100
Regulatory liabilities *(Note 11)*	47	85
Derivative instruments *(Note 13)*	3	–
Long-term debt payable within one year (includes $252 measured at fair value; 2013 – $506) *(Notes 12, 13)*	552	756
	1,715	1,991
Long-term debt (includes $nil measured at fair value; 2013 – $256) *(Notes 12, 13)*	8,373	8,301
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,533	1,488
Deferred income tax liabilities *(Note 7)*	1,313	1,129
Pension benefit liability *(Note 15)*	1,236	845
Environmental liabilities *(Note 16)*	221	239
Regulatory liabilities *(Note 11)*	168	163
Net unamortized debt premiums	18	20
Asset retirement obligations *(Note 17)*	9	14
Long-term accounts payable and other liabilities	17	20
	4,515	3,918
Total liabilities	**14,603**	**14,210**
Contingencies and commitments (Notes 22, 23)		
Subsequent Event (Note 25)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	323	323
Noncontrolling interest subject to redemption *(Note 4)*	21	–
Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	3,314	3,314
Retained earnings	4,249	3,787
Accumulated other comprehensive loss	(9)	(9)
Noncontrolling interest *(Note 4)*	49	–
Total equity	**7,603**	**7,092**
	22,550	**21,625**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Sandra Pupatello
Chair

George L. Cooke

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2014 and 2013

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total Equity**
January 1, 2014	3,314	3,787	(9)	–	7,092
Net income	–	749	–	(1)	748
Other comprehensive income	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	50	50
Dividends on preferred shares	–	(18)	–	–	(18)
Dividends on common shares	–	(269)	–	–	(269)
December 31, 2014	3,314	4,249	(9)	(49)	7,603

Year ended December 31, 2013 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total Equity**
January 1, 2013	3,314	3,202	(9)	–	6,507
Net income	–	803	–	–	803
Other comprehensive income	–	–	–	–	–
Dividends on preferred shares	–	(18)	–	–	(18)
Dividends on common shares	–	(200)	–	–	(200)
December 31, 2013	3,314	3,787	(9)	–	7,092

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Operating activities		
Net income	747	803
Environmental expenditures	(18)	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	641	597
Regulatory assets and liabilities	(69)	3
Deferred income taxes	10	(2)
Other	–	8
Changes in non-cash balances related to operations *(Note 21)*	(55)	11
Net cash from operating activities	1,256	1,404
Financing activities		
Long-term debt issued	628	1,185
Long-term debt retired	(776)	(600)
Amount contributed by noncontrolling interest *(Note 4)*	72	–
Dividends paid	(287)	(218)
Change in bank indebtedness	(29)	(11)
Other	(3)	(5)
Net cash from (used in) financing activities	(395)	351
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	(1,481)	(1,308)
Intangible assets	(23)	(79)
Acquisition of Norfolk Power Inc. *(Note 4)*	(66)	–
Proceeds from investment	250	–
Other	(6)	2
Net cash used in investing activities	(1,326)	(1,385)
Net change in cash and cash equivalents	(465)	370
Cash and cash equivalents, beginning of year	565	195
Cash and cash equivalents, end of year	**100**	**565**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. The electricity rates of these businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., Hydro One Lake Erie Link Company Inc., Norfolk Power Inc. (Norfolk Power), and Hydro One B2M Holdings. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Hydro One performed an evaluation of subsequent events through to February 11, 2015, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 25 – Subsequent Event.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's Transmission Business includes the separately regulated transmission businesses of Hydro One Networks and B2M Limited Partnership (B2M LP). The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks and the newly acquired Norfolk Power, as well as the subsidiaries Hydro One Brampton Networks and Hydro One Remote Communities.

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Up to the year ended December 31, 2014, Hydro One Brampton Networks used Canadian GAAP (Part V) for its distribution rate-setting purposes, and has transitioned to International Financial Reporting Standards beginning on January 1, 2015.

Transmission

In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 and 2014 transmission rates. In December 2012, the OEB approved the 2013 and 2014 revenue requirement of $1,438 million and $1,528 million, respectively.

In December 2013, Hydro One Networks filed a draft Rate Order with the OEB for 2014 transmission rates. The 2014 transmission revenue requirement was increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

Distribution

In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In April 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 0.3% in 2013, or less than 0.1% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in a reduction in distribution rates of approximately 2.3% in 2014, or 0.5% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 rates, seeking approval for a 2013 revenue requirement of $53 million. In June 2013, the OEB approved a revenue requirement of $51 million for 2013. In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 rates, seeking approval for a rate increase of approximately 0.5%. In March 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB's updated rate adjustment parameters and Hydro One Remote Communities' IRM stretch factor.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been 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 Company's 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 Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. 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 setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution 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 estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the final amount billed is not received within 110 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the Shareholder of the parent company. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred 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 at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major company-wide computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate	
		Range	Average
Transmission	57 years	1% – 2%	2%
Distribution	42 years	1% – 20%	2%
Communication	19 years	1% – 15%	4%
Administration and service	15 years	3% – 20%	7%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 20%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2014, based on the qualitative assessment performed as at September 30, 2014, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2014.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2014, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt issuance costs on the Consolidated Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 13 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges which either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2014 or 2013.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates 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 are amortized to results of operations based on the expected average remaining service period.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks and the newly acquired Norfolk Power participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both the participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983. At December 31, 2013, OMERS had approximately 440,000 members, with approximately 335 members being current employees of Hydro One Brampton Networks and Norfolk Power.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks and Norfolk Power employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, 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 Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. The adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

Recent Accounting Guidance Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This ASU is effective for the annual period ending December 31, 2016, and for annual and interim periods thereafter. The adoption of this ASU is not anticipated to have a significant impact on the Company's consolidated financial statements.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815). This ASU provides guidance on accounting for hybrid financial instruments issued in the form of a share. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of ASU 2014-16 on its consolidated financial statements.

4. BUSINESS COMBINATIONS

B2M Limited Partnership

In 2012, Hydro One entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the Saugeen Ojibway Nation (SON), where a noncontrolling equity interest in Hydro One's new limited partnership, B2M LP, would be made available for purchase at fair value by the SON. B2M LP was formed by Hydro One in 2013 to hold most of the transmission lines and a licence to use the related land. These assets are associated with Hydro One's Bruce to Milton Transmission Reinforcement Project, an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to Hydro One's Milton Switching Station in the Town of Milton. Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. In November 2013, the OEB issued a Decision and Order granting B2M LP a transmission licence and granting Hydro One Networks leave to sell the relevant Bruce to Milton Line transmission assets to B2M LP.

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired.

Part of the SON's equity interest in B2M LP is in Class B units of B2M LP that have a mandatory put option. The put option requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), the SON has the ability to require Hydro One to purchase the Class B units of B2M LP for net book value on the redemption date.

The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity. At December 31, 2014, the total noncontrolling interest was reduced by the 2014 net loss attributable to noncontrolling interest totalling $2 million, including $1 million relating to noncontrolling interest subject to redemption.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power, an electricity distribution and telecom company located in southwestern Ontario. The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, is approximately $68 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and therefore the actual total purchase price and the consequent impact on goodwill may differ from the amounts above.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. None of the goodwill recognized is expected to be deductible for income tax purposes.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014.

All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. The disclosure of Norfolk Power's pro forma information is immaterial to the Company's consolidated financial results for the year ended December 31, 2014.

Woodstock Hydro Purchase Agreement

On May 21, 2014, Hydro One reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Woodstock Hydro will be approximately $29 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Woodstock Hydro acquisition, the Company made a refundable deposit totalling $2 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

Haldimand Hydro Purchase Agreement

On June 10, 2014, Hydro One reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Haldimand Hydro will be approximately $65 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Haldimand Hydro acquisition, the Company made a refundable deposit totalling $3 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Depreciation of property, plant and equipment	565	533
Amortization of intangible assets	53	48
Asset removal costs	81	79
Amortization of regulatory assets	23	16
	722	676

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Interest on long-term debt	432	416
Other	12	9
Less: Interest capitalized on construction and development in progress	(49)	(51)
Gain on interest-rate swap agreements	(10)	(11)
Interest earned on investments	(6)	(3)
	379	360

7. 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 the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Income before provision for PILs	836	912
Canadian federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	222	242
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(72)	(72)
Pension contributions in excess of pension expense	(24)	(23)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(14)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(4)
Prior year's adjustments	(4)	(8)
Non-refundable investment tax credits	(3)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	3	4
Other	(1)	(1)
Net temporary differences	(134)	(135)
Net permanent differences	1	2
Total provision for PILs	89	109

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current provision for PILs	79	111
Deferred provision (recovery) for PILs	10	(2)
Total provision for PILs	89	109
Effective income tax rate	10.63%	11.98%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $39 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (2013 – $29 million).

At December 31, 2014, the total provision for PILs includes deferred provision for PILs of $10 million (2013 – deferred recovery of $2 million) that is not included in the rate-setting process, using the liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	8	7
Environmental expenditures	4	5
Depreciation and amortization in excess of capital cost allowance	(4)	–
Other	(1)	(1)
Total deferred income tax assets	7	11
Less: current portion	–	–
	7	11

December 31 (millions of Canadian dollars)	**2014**	**2013**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,713)	(1,556)
Regulatory amounts that are not recognized for tax purposes	(140)	(144)
Partnership interest	(38)	–
Goodwill	(21)	(20)
Post-retirement and post-employment benefits expense in excess of cash payments	559	542
Environmental expenditures	59	66
Other	–	1
Total deferred income tax liabilities	(1,294)	(1,111)
Less: current portion	19	18
	(1,313)	(1,129)

During 2014 and 2013, there were no changes in the rate applicable to future taxes.

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	**2014**	**2013**
Accounts receivable – billed	496	268
Accounts receivable – unbilled	586	691
Accounts receivable, gross	1,082	959
Allowance for doubtful accounts	(66)	(36)
Accounts receivable, net	1,016	923

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Allowance for doubtful accounts – January 1	(36)	(23)
Write-offs	24	24
Additions to allowance for doubtful accounts	(54)	(37)
Allowance for doubtful accounts – December 31	(66)	(36)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2014 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,209	4,416	626	9,419
Distribution	9,076	3,225	320	6,171
Communication	1,100	615	56	541
Administration and Service	1,502	793	23	732
Easements	623	85	–	538
	25,510	9,134	1,025	17,401

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,413	4,215	671	8,869
Distribution	8,498	3,046	316	5,768
Communication	1,060	560	53	553
Administration and Service	1,380	716	38	702
Easements	617	78	–	539
	23,968	8,615	1,078	16,431

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2014 (2013 – $48 million).

10. INTANGIBLE ASSETS

December 31, 2014 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	573	303	3	273
Other	5	2	–	3
	578	305	3	276

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	557	249	3	311
Other	5	3	–	2
	562	252	3	313

Financing charges capitalized on intangible assets under development were $1 million in 2014 (2013 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2015 – $53 million; 2016 – $53 million; 2017 – $53 million; 2018 – $45 million; and 2019 – $31 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Regulatory assets:		
Deferred income tax regulatory asset	1,327	1,145
Pension benefit regulatory asset	1,236	845
Post-retirement and post-employment benefits	273	308
Environmental	239	266
Pension cost variance	90	80
DSC exemption	16	7
OEB cost assessment differential	12	9
Retail settlement variance accounts	11	–
Long-term project development costs	–	5
Other	27	18
Total regulatory assets	3,231	2,683
Less: current portion	31	47
	3,200	2,636
Regulatory liabilities:		
Rider 11	83	55
External revenue variance	54	81
CDM deferral variance account	25	–
Deferred income tax regulatory liability	21	19
PST savings deferral	19	17
Hydro One Brampton Networks rider	2	8
Retail settlement variance accounts	–	35
Rider 9	–	19
Other	11	14
Total regulatory liabilities	215	248
Less: current portion	47	85
	168	163

Deferred Income Tax Regulatory Asset and Liability

Deferred 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 profit. The Company has recognized regulatory assets and liabilities that correspond to deferred 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 2014 provision for PILs would have been higher by approximately $132 million (2013 – $139 million).

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2014 OCI would have been lower by $391 million (2013 – higher by $670 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2014 OCI would have been higher by $35 million (2013 – $12 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2014, the environmental regulatory asset decreased by $33 million (2013 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $13 million (2013 – $26 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been lower by $20 million (2013 – higher by $23 million). In addition, 2014 amortization expense would have been lower by $18 million (2013 – $16 million), and 2014 financing charges would have been higher by $11 million (2013 – $10 million).

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2014 revenue would have been lower by $10 million (2013 – $19 million).

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review until the next Hydro One Networks' distribution cost-of-service application. This program effectively ended at the end of 2014 with no new principal to be recorded in 2015.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution rate application for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments. This continued for 2012-2014 until the next Hydro One Networks' distribution cost-of-service application, which was submitted in 2014. This program effectively ended at the end of 2014 with no new activity to be recorded in 2015.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. At December 31, 2014, the RSVA was in a net asset position due to a change in global adjustment.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

Rider 11

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received. Rider 11 includes amounts previously included as Rider 8.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. The OEB rate order specifically states that the Ontario Power Authority (OPA) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the OPA of actual results. This notification from the OPA typically occurs in September of each year.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account, per direction from the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2014 and recorded in a deferral account, per direction from the OEB.

Hydro One Brampton Networks Rider

In December 2013, the OEB issued a decision for Hydro One Brampton Networks' 2014 distribution rates. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from January 1, 2014 to December 31, 2015.

Rider 9

In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2014 and 2013.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2019. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and supports the Company's Commercial Paper Program. The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
3.13% Series 19 notes due 2014[1]	–	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	50
5.18% Series 13 notes due 2017	600	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[2]	228	–
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	600
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	–
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	–
	8,923	9,045
Add: Unrealized mark-to-market loss[1]	2	12
Less: Long-term debt payable within one year	(552)	(756)
Long-term debt	8,373	8,301

[1] The unrealized mark-to-market loss relates to $250 million of the Series 21 notes due 2015 (2013 – $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $2 million (2013 – $12 million) unrealized mark-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 13 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2014, Hydro One issued $628 million (2013 – $1,185 million) of long-term debt under the MTN Program, and repaid the $750 million MTN Series 19 notes (2013 – repaid $600 million MTN Series 15 notes). In addition, the Company repaid long-term debt totalling $26 million assumed on the Norfolk Power acquisition.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 13 – Fair Value of Financial Instruments and Risk Management.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2014 and 2013, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2014 and 2013 are as follows:

December 31 (millions of Canadian dollars)	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	–	–	506	506
$250 million of MTN Series 21 notes[1]	252	252	256	256
Other notes and debentures[2]	8,673	10,159	8,295	9,018
	8,925	10,411	9,057	9,780

[1] The fair value of $500 million of the MTN Series 19 notes and of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2014, the Company had interest-rate swaps totalling $250 million (2013 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 3% (2013 – 8%) of its total long-term debt of $8,925 million (2013 – $9,057 million). At December 31, 2014, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable-rate debt.

At December 31, 2014, the Company also had interest-rate swaps with a total notional value of $409 million (2013 – $900 million) classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(b) a $150 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2014 to September 11, 2015;
(c) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2014 to January 24, 2015;

(d) a $137 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $228 million floating-rate MTN Series 31 notes from December 22, 2014 to December 21, 2015;

(e) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from March 3, 2015 to December 3, 2015;

(f) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 26, 2015 to July 24, 2015; and

(g) three interest-rate swaps with a total notional value of $12 million that were assumed as part of the Norfolk Power acquisition. These swaps consist of $8 million and $2 million floating-to-fixed interest-rate swap agreements maturing on September 20, 2029, and a $2 million floating-to-fixed interest-rate swap agreement maturing on September 20, 2019.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 is as follows:

December 31, 2014 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	565	565	565	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	12	12	–	12	–
	828	828	565	263	–
Liabilities:					
Bank indebtedness	31	31	31	–	–
Long-term debt	9,057	9,780	–	9,780	–
	9,088	9,811	31	9,780	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2014, short-term investments consisted of bankers' acceptances and money market funds totalling $nil (2013 – $515 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment at December 31, 2013 represented the Province of Ontario Floating-Rate Notes that matured in November 2014. The fair value of the investment was determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtained quotes from an independent third party for the fair value of the investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2014 and 2013.

Risk Management

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 capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Transmission and Distribution Businesses is derived using a formulaic approach that 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 forecasted 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 the Transmission Business' 2014 annual results of operations by approximately $20 million (2013 – $19 million) and Hydro One Networks' distribution business' 2014 annual results of operations by approximately $10 million (2013 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest-rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were in existence as at December 31, 2014 or 2013.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2014 or 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of

Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2014 and 2013 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Unrealized loss (gain) on hedged debt	(3)	(8)
Unrealized loss (gain) on fair value interest-rate swaps	3	8
Net unrealized loss (gain)	–	–

At December 31, 2014, Hydro One had $250 million (2013 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $2 million (2013 – $12 million). During the years ended December 31, 2014 and 2013, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2014 and 2013, 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, Hydro One did not earn a significant amount of revenue from any single customer. At December 31, 2014 and 2013, there was no significant accounts receivable balance due from any single customer.

At December 31, 2014, the Company's provision for bad debts was $66 million (2013 – $36 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2014, approximately 6% of the Company's net accounts receivable were aged more than 60 days (2013 – 4%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company'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. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2014, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $3 million (2013 – $14 million). At December 31, 2014, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with five financial institutions as the counterparties. The credit exposure of three of the five counterparties accounted for more than 10% of the total credit exposure of derivative contracts.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facility of $1,500 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2014, accounts payable and accrued liabilities in the amount of $784 million (2013 – $789 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2014, Hydro One had issued long-term debt in the principal amount of $8,923 million (2013 – $9,045 million). Principal repayments, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Long-term Debt Principal Repayments** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	550	419	2.8
2 years	500	393	4.3
3 years	600	381	5.2
4 years	750	350	2.8
5 years	228	327	1.6
	2,628	1,870	3.5
6 – 10 years	900	1,522	3.6
Over 10 years	5,395	4,373	5.4
	8,923	7,765	4.7

14. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of Shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2014 and 2013, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Long-term debt payable within one year	552	756
Less: cash and cash equivalents	100	565
	452	191
Long-term debt	8,373	8,301
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	4,249	3,787
	7,563	7,101
Total capital	16,711	15,916

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2014 and 2013, Hydro One was in compliance with all of these covenants and limitations.

15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except employees of Hydro One Brampton Networks and Norfolk Power. Employees of Hydro One Brampton Networks and Norfolk Power participate in the OMERS plan. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2014 were $2 million (2013 – $2 million). Company contributions payable at December 31, 2014 and included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2013 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2013.

At December 31, 2013, the OMERS plan was 88.2% funded, with an unfunded liability of $8,641 million. This unfunded liability could result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The 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 Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2014 of $174 million (2013 – $160 million) were based on an actuarial valuation effective December 31, 2013 (2013 – effective December 31, 2011) and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2015 and 2016 are approximately $174 million and $175 million, respectively, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	6,576	6,507	1,531	1,459
Current service cost	145	170	41	40
Interest cost	312	278	73	63
Reciprocal transfers	–	1	–	–
Benefits paid	(319)	(317)	(45)	(44)
Net actuarial loss (gain)	821	(63)	(18)	13
Projected benefit obligation, end of year	7,535	6,576	1,582	1,531
Change in plan assets				
Fair value of plan assets, beginning of year	5,731	4,992	–	–
Actual return on plan assets	703	887	–	–
Reciprocal transfers	–	1	–	–
Benefits paid	(319)	(317)	–	–
Employer contributions	174	160	–	–
Employee contributions	35	30	–	–
Administrative expenses	(25)	(22)	–	–
Fair value of plan assets, end of year	6,299	5,731	–	–
Unfunded status	1,236	845	1,582	1,531

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Accrued liabilities	–	–	49	43
Pension benefit liability	1,236	845	–	–
Post-retirement and post-employment benefit liability	–	–	1,533	1,488
Unfunded status	1,236	845	1,582	1,531

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 (millions of Canadian dollars)	**2014**	**2013**
PBO	7,535	6,576
ABO	6,887	5,998
Fair value of plan assets	6,299	5,731

On an ABO basis, the Pension Plan was funded at 91% at December 31, 2014 (2013 – 96%). On a PBO basis, the Pension Plan was funded at 84% at December 31, 2014 (2013 – 87%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2014 and 2013 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current service cost, net of employee contributions	110	141
Interest cost	312	278
Expected return on plan assets, net of expenses	(369)	(309)
Actuarial loss amortization	103	175
Prior service cost amortization	2	2
Net periodic benefit costs	158	287
Charged to results of operations[1]	81	72

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2014, pension costs of $174 million (2013 – $160 million) were attributed to labour, of which $81 million (2013 – $72 million) was charged to operations, and $93 million (2013 – $88 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2014 and 2013 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Current service cost, net of employee contributions	41	40
Interest cost	73	63
Actuarial loss amortization	18	27
Prior service cost amortization	2	3
Net periodic benefit costs	134	133
Charged to results of operations	62	58

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2014 and 2013:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2014**	**2013**	**2014**	**2013**
Significant assumptions:				
Weighted average discount rate	4.00%	4.75%	4.00%	4.75%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	–	–	4.36%	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2013 – 6.81% in 2014, grading down to 4.39% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2014 and 2013. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	**2014**	**2013**
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.25%
Weighted average discount rate	4.75%	4.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	4.75%	4.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	12	12
Rate of increase in health care cost trends[1]	4.39%	4.39%

[1] 6.81% per annum in 2014, grading down to 4.39% per annum in and after 2031 (2013 – 6.91% in 2013, grading down to 4.39% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2014 and 2013 is as follows:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	248	258
Effect of a 1% decrease in health care cost trends	(193)	(200)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2014 and 2013 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	23	21
Effect of a 1% decrease in health care cost trends	(17)	(16)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2014 and 2013:

December 31, 2014				**December 31, 2013**			
Life expectancy at 65 for a member currently at				**Life expectancy at 65 for a member currently at**			
Age 65		**Age 45**		**Age 65**		**Age 45**	
Male	Female	Male	Female	Male	Female	Male	Female
23	25	24	26	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2014, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2015	305	50
2016	316	52
2017	328	54
2018	339	56
2019	350	59
2020 through to 2024	1,889	332
Total estimated future benefit payments through to 2024	3,527	603

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Pension Benefits:		
Actuarial loss (gain) for the year	511	(619)
Actuarial loss amortization	(103)	(175)
Prior service cost amortization	(2)	(2)
	406	(796)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(18)	13
Actuarial loss amortization	(18)	(27)
Prior service cost amortization	(2)	(3)
	(38)	(17)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Pension Benefits:		
Prior service cost	2	3
Actuarial loss	1,234	842
	1,236	845
Post-Retirement and Post-Employment Benefits:		
Prior service cost	–	2
Actuarial loss	273	306
	273	308

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Prior service cost	2	2	–	2
Actuarial loss	119	103	10	15
	121	105	10	17

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Audit, Finance and Pension Investment Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2014, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	60.9
Debt securities	35.0	35.9
Other[1]	5.0	3.2
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2014, the Pension Plan held no Hydro One corporate bonds (2013 – $15 million) and $340 million of debt securities of the Province (2013 – $217 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2014 and 2013. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2014 and 2013, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "A+" by Standard and Poor's Rating Services Inc., DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service Inc., and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2014 and 2013:

December 31, 2014 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	–	18	142	160
Cash and cash equivalents	166	–	–	166
Short-term securities	–	176	–	176
Real estate	–	–	2	2
Corporate shares – Canadian	1,008	–	–	1,008
Corporate shares – Foreign	2,766	–	–	2,766
Bonds and debentures – Canadian	–	1,799	–	1,799
Bonds and debentures – Foreign	–	211	–	211
Total fair value of plan assets[1]	3,940	2,204	144	6,288

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

December 31, 2013 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	1	16	117	134
Cash and cash equivalents	150	–	–	150
Short-term securities	–	180	–	180
Real estate	–	–	2	2
Corporate shares – Canadian	943	–	–	943
Corporate shares – Foreign	2,708	–	–	2,708
Bonds and debentures – Canadian	–	1,416	–	1,416
Bonds and debentures – Foreign	–	186	–	186
Total fair value of plan assets[1]	3,802	1,798	119	5,719

[1] At December 31, 2013, the total fair value of Pension Plan assets excludes $19 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

See Note 13 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2014 and 2013. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Fair value, beginning of year	119	106
Realized and unrealized gains	30	23
Purchases	23	–
Sales and disbursements	(28)	(10)
Fair value, end of year	144	119

There were no significant transfers between any of the fair value levels during the years ended December 31, 2014 and 2013.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Infrastructure investments represent infrastructure funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2014 and 2013:

Year ended December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	197	52	249
Interest accretion	9	1	10
Expenditures	(2)	(14)	(16)
Revaluation adjustment	(3)	26	23
Environmental liabilities, December 31	201	65	266
Less: current portion	15	12	27
	186	53	239

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	237	68	305
Less: discounting accumulated liabilities to present value	36	3	39
Discounted environmental liabilities	201	65	266

At December 31, 2014, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015	18
2016	37
2017	36
2018	35
2019	33
Thereafter	106
	265

At December 31, 2014, of the total estimated future environmental expenditures, \$195 million relates to PCBs (2013 – \$237 million) and \$70 million relates to LAR (2013 – \$68 million).

Hydro One records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

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. 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 rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. In addition, with respect to the PCB environmental liability, 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $195 million. These expenditures are expected to be incurred over the period from 2015 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to reduce the PCB environmental liability by $33 million (2013 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $70 million. These expenditures are expected to be incurred over the period from 2015 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to increase the LAR environmental liability by $13 million (2013 – $26 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for 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 approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's AROs represent management's best estimates of the 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 Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2014, Hydro One had recorded AROs of $9 million (2013 – $14 million), consisting of $8 million (2013 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $1 million (2013 – $7 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2014. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and Shareholder expectations.

Earnings per Share

Basic and diluted earnings per share have been calculated on the basis of net income attributable to the Shareholder of Hydro One and the weighted average number of common shares outstanding during the year.

19. DIVIDENDS

In 2014, preferred share dividends in the amount of $18 million (2013 – $18 million) and common share dividends in the amount of $269 million (2013 – $200 million) were declared.

20. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, OPA, Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province.

The Province

During 2014, Hydro One paid dividends to the Province totalling $287 million (2013 – $218 million).

In November 2014, the Company redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

In 2014, Hydro One purchased power in the amount of $2,601 million (2013 – $2,477 million) from the IESO-administered electricity market.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2014 include $1,556 million (2013 – $1,509 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2014 include $127 million (2013 – $127 million) related to this program.

Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues for 2014 include $32 million (2013 – $33 million) related to these services.

OPA

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2014, Hydro One received $33 million (2013 – $34 million) from the OPA related to these programs.

OPG

In 2014, Hydro One purchased power in the amount of $23 million (2013 – $15 million) from OPG.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2014, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $12 million (2013 – $9 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2014 related to the purchase of services with respect to these service level agreements were $1 million (2013 – $1 million).

OEFC

In 2014, Hydro One made payments in lieu of corporate income taxes to the OEFC totalling $86 million (2013 – $138 million).

In 2014, Hydro One purchased power in the amount of $9 million (2013 – $8 million) from power contracts administered by the OEFC.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

PILs and payments in lieu of property taxes are paid to the OEFC.

OEB

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 transmitters. In 2014, Hydro One incurred $12 million (2013 – $12 million) in OEB fees.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Due from related parties	224	197
Due to related parties[1]	(227)	(230)
Investment	–	251

[1] Included in due to related parties at December 31, 2014 are amounts owing to the IESO in respect of power purchases of $214 million (2013 – $217 million).

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Accounts receivable	(93)	(78)
Due from related parties	(27)	(43)
Prepaid expenses and other assets	(13)	(5)
Accounts payable	39	13
Accrued liabilities	(35)	71
Due to related parties	(3)	(31)
Accrued interest	–	5
Long-term accounts payable and other liabilities	(3)	(5)
Post-retirement and post-employment benefit liability	80	84
	(55)	11

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in property, plant and equipment	(1,511)	(1,312)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	30	4
Capital expenditures – property, plant and equipment	(1,481)	(1,308)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in intangible assets	(19)	(82)
Net change in accruals included in capital investments in intangible assets	(4)	3
Capital expenditures – intangible assets	(23)	(79)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Net interest paid	412	395
PILs	86	138

22. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2014, the Company paid approximately $1 million (2013 – $2 million) in respect of these consents. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

23. COMMITMENTS

Outsourcing Agreements

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, Hydro One entered into an agreement with Inergi (Inergi Agreement), the service provider selected through a competitive procurement process which began in 2013, for second-generation back office and IT outsourcing services for a term of 58 months, commencing March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide Hydro One with settlements, source to pay services, pay operations services, information technology and finance and accounting services. Coincident with the conclusion of negotiations on the Inergi Agreement, Hydro One reached agreement with Inergi for the provision of second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In September 2014, Hydro One entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield) for facilities management services for a term of ten years, from January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by the Company. The Brookfield Agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by the Company, with no minimum capital work guarantee. The agreement also includes a fixed management fee of approximately $2 million for each year of the term.

At December 31, 2014, the annual commitments under the outsourcing agreements were as follows: 2015 – $179 million; 2016 – $146 million; 2017 – $145 million; 2018 – $113 million; 2019 – $105 million; and thereafter – $13 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2014, the Company provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $330 million (2013 – $325 million), and on behalf of two distributors using guarantees of $1 million (2013 – $1 million). In addition, as at December 31, 2014, the Company has provided letters of credit in the amount of $8 million (2013 – $21 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2014, Hydro One had letters of credit of $126 million (2013 – $127 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have a typical term of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

During the year ended December 31, 2014, the Company made lease payments totalling $11 million (2013 – $11 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $7 million; 2016 – $10 million; 2017 – $9 million; 2018 – $7 million; 2019 – $3 million; and thereafter – $9 million.

24. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, which includes certain corporate activities and the operations of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2014 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,588	4,903	57	6,548
Purchased power	–	3,419	–	3,419
Operation, maintenance and administration	394	742	56	1,192
Depreciation and amortization	346	367	9	722
Income (loss) before financing charges and provision for PILs	848	375	(8)	1,215
Capital investments	845	680	5	1,530

Year ended December 31, 2013 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,529	4,484	61	6,074
Purchased power	–	3,020	–	3,020
Operation, maintenance and administration	375	672	59	1,106
Depreciation and amortization	327	340	9	676
Income (loss) before financing charges and provision for PILs	827	452	(7)	1,272
Capital investments	714	673	7	1,394

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Transmission	12,540	11,846
Distribution	9,805	8,805
Other	205	974
Total assets	22,550	21,625

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. SUBSEQUENT EVENT

On February 11, 2015, preferred share dividends in the amount of $4 million and common share dividends in the amount of $25 million were declared.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2014.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013. The effectiveness of these internal controls and findings is reported to the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had irect and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the Chief Administration Officer and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One Inc.'s management:

Carmine Marcello
President and Chief Executive Officer

Sandy Struthers
Chief Administration Officer and Chief Financial Officer

HYDRO ONE INC.
INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated 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 Consolidated 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 Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated 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 Consolidated 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 Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2013 and December 31, 2012, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 13, 2014

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2013**	**2012**
Revenues		
Distribution (includes $160 related party revenues; 2012 – $155) *(Note 20)*	4,484	4,184
Transmission (includes $1,517 related party revenues; 2012 – $1,482) *(Note 20)*	1,529	1,482
Other	61	62
	6,074	5,728
Costs		
Purchased power (includes $2,500 related party costs; 2012 – $2,409) *(Note 20)*	3,020	2,774
Operation, maintenance and administration *(Note 20)*	1,106	1,071
Depreciation and amortization *(Note 5)*	676	659
	4,802	4,504
Income before financing charges and provision for payments in lieu of corporate income taxes	1,272	1,224
Financing charges *(Note 6)*	360	358
Income before provision for payments in lieu of corporate income taxes	912	866
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	109	121
Net income	803	745
Other comprehensive income	–	1
Comprehensive income	803	746
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	7,850	7,280
Dividends per common share declared *(dollars) (Note 19)*	2,000	3,523

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	**2012**
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	565	195
Accounts receivable (net of allowance for doubtful accounts – \$36; 2012 – \$23) *(Note 8)*	923	845
Due from related parties *(Note 20)*	197	154
Regulatory assets *(Note 11)*	47	29
Materials and supplies	23	23
Deferred income tax assets *(Note 7)*	18	18
Derivative instruments *(Note 13)*	6	–
Investment *(Notes 13, 20)*	251	–
Other	28	22
	2,058	1,286
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	23,820	22,650
Less: accumulated depreciation	8,615	8,145
	15,205	14,505
Construction in progress	1,078	1,055
Future use land, components and spares	148	147
	16,431	15,707
Other long-term assets:		
Regulatory assets *(Note 11)*	2,636	3,098
Investment *(Notes 13, 20)*	–	251
Intangible assets (net of accumulated amortization – \$252; 2012 – \$305) *(Note 10)*	313	267
Goodwill	133	133
Deferred debt costs	36	34
Derivative instruments *(Note 13)*	6	19
Deferred income tax assets *(Note 7)*	11	14
Other	1	2
	3,136	3,818
Total assets	21,625	20,811

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2013 and 2012

December 31 (millions of Canadian dollars, except number of shares)	**2013**	**2012**
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	31	42
Accounts payable	62	140
Accrued liabilities *(Notes 7, 15, 16)*	733	578
Due to related parties *(Note 20)*	230	261
Accrued interest	100	95
Regulatory liabilities *(Note 11)*	85	40
Long-term debt payable within one year (includes $506 measured at fair value; 2012 – $0) *(Notes 12, 13)*	756	600
	1,997	1,756
Long-term debt (includes $256 measured at fair value; 2012 – $769) *(Notes 12, 13)*	8,301	7,879
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,488	1,416
Deferred income tax liabilities *(Note 7)*	1,129	944
Pension benefit liability *(Note 15)*	845	1,515
Environmental liabilities *(Note 16)*	239	227
Regulatory liabilities *(Note 11)*	163	181
Net unamortized debt premiums	20	23
Asset retirement obligations *(Note 17)*	14	15
Long-term accounts payable and other liabilities	14	25
	3,912	4,346
Total liabilities	14,210	13,981
Contingencies and commitments (Notes 22, 23)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	323	323
Shareholder's equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	3,314	3,314
Retained earnings	3,787	3,202
Accumulated other comprehensive loss	(9)	(9)
Total shareholder's equity	7,092	6,507
Total liabilities, preferred shares and shareholder's equity	21,625	20,811

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
For the years ended December 31, 2013 and 2012

Year ended December 31, 2013 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2013	3,314	3,202	(9)	6,507
Net income	–	803	–	803
Other comprehensive income	–	–	–	–
Dividends on preferred shares	–	(18)	–	(18)
Dividends on common shares	–	(200)	–	(200)
December 31, 2013	3,314	3,787	(9)	7,092

Year ended December 31, 2012 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2012	3,314	2,827	(10)	6,131
Net income	–	745	–	745
Other comprehensive income	–	–	1	1
Dividends on preferred shares	–	(18)	–	(18)
Dividends on common shares	–	(352)	–	(352)
December 31, 2012	3,314	3,202	(9)	6,507

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Operating activities		
Net income	803	745
Environmental expenditures	(16)	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	597	589
Regulatory assets and liabilities	3	12
Deferred income taxes	(2)	(9)
Other	8	6
Changes in non-cash balances related to operations *(Note 21)*	11	(31)
Net cash from operating activities	1,404	1,294
Financing activities		
Long-term debt issued	1,185	1,085
Long-term debt retired	(600)	(600)
Dividends paid	(218)	(370)
Change in bank indebtedness	(11)	3
Other	(5)	(1)
Net cash from financing activities	351	117
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	(1,333)	(1,373)
Intangible assets	(79)	(90)
Other	27	19
Net cash used in investing activities	(1,385)	(1,444)
Net change in cash and cash equivalents	370	(33)
Cash and cash equivalents, beginning of year	195	228
Cash and cash equivalents, end of year	565	195

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. The electricity rates of these businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., and Hydro One Lake Erie Link Company Inc.

Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. Certain comparative figures have been reclassified to conform to the presentation of these Consolidated Financial Statements (see Note 21 – Consolidated Statements of Cash Flows). In the opinion of management, these Consolidated Financial Statements include all adjustments that are necessary to fairly state the financial position and results of operations of Hydro One as at, and for the year ended December 31, 2013.

Hydro One performed an evaluation of subsequent events through to February 13, 2014, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 25 – Subsequent Event.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's Transmission Business includes the separately regulated transmission business of Hydro One Networks. The Company's consolidated Distribution Business includes Hydro One Brampton Networks, Hydro One Remote Communities, as well as the separately regulated distribution business of Hydro One Networks.

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Hydro One Brampton Networks currently uses Canadian GAAP for its distribution rate-setting purposes.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application with the OEB for 2012 transmission rates. The OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012. In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 transmission rates, seeking approval for a 2013 revenue requirement of $1,465 million. In December 2012, the OEB approved a revenue requirement of $1,438 million for 2013. The reduced approved revenue requirement included reductions to proposed operation, maintenance and administration costs, and capital expenditures.

Distribution

In 2010, the OEB approved a revised 2011 revenue requirement of $1,218 million and 2011 distribution rates. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year. In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 1.3%, with an effective date of January 1, 2013.

In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates. In January 2012, the OEB approved a reduction in distribution rates of approximately 13.2%, with an effective date of January 1, 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates. In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 0.3%, with an effective date of January 1, 2013.

In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012. In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 rates, seeking approval for a 2013 revenue requirement of $53 million. In June 2013, the OEB approved a revenue requirement of $51 million for 2013.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been 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 Company's 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 Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. 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 setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution 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 estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 110 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgement is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred 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 at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate (%) Range	Rate (%) Average
Transmission	57 years	1% – 2%	2%
Distribution	42 years	1% – 20%	2%
Communication	19 years	1% – 15%	5%
Administration and service	15 years	3% – 20%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 10%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2013, based on the qualitative assessment performed as at September 30, 2013, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2013.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2013, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Consolidated Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's discontinued cash flow hedges, and the change in fair value on the 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. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 13 – Fair Value of Financial Instruments and Risk Management.

The Company's investment in Province of Ontario Floating-Rate Notes, which is held as an alternate form of liquidity to supplement the bank credit facilities, is classified as held-for-trading and is measured at fair value.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized in its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2013 or 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset on the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates 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 are amortized to results of operations based on the expected average remaining service period.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983. At December 31, 2012, OMERS had approximately 429,000 members, with approximately 283 members being current employees of Hydro One Brampton Networks.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgements regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgements about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) 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. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, 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 Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets.

If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have an impact on the Company's Consolidated Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. The adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. BUSINESS ACQUISITION

Norfolk Power Purchase Agreement

On April 2, 2013, Hydro One reached an agreement with The Corporation of Norfolk County to acquire 100% of the common shares of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Norfolk Power will be approximately $93 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2014. In anticipation of the Norfolk Power acquisition, the Company made a refundable deposit totaling $5 million, which was recorded in other current assets on the interim Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Depreciation of property, plant and equipment	533	522
Amortization of intangible assets	48	48
Asset removal costs	79	70
Amortization of regulatory assets	16	19
	676	659

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Interest on long-term debt	416	421
Other	9	12
Less: Interest capitalized on construction and development in progress	(51)	(59)
Gain on interest-rate swap agreements	(11)	(12)
Interest earned on investments	(3)	(4)
	360	358

7. 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 the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Income before provision for PILs	912	866
Canadian federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	242	230
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(72)	(42)
Pension contributions in excess of pension expense	(23)	(23)
Interest capitalized for accounting but deducted for tax purposes	(13)	(15)
Overheads capitalized for accounting but deducted for tax purposes	(14)	(14)
Prior year's adjustments	(8)	(2)
Non-refundable investment tax credits	(4)	(8)
Environmental expenditures	(4)	(5)
Post-retirement and post-employment benefit expense in excess of cash payments	4	–
Other	(1)	(1)
Net temporary differences	(135)	(110)
Net permanent differences	2	1
Total provision for PILs	109	121

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current provision for PILs	111	130
Deferred recovery of PILs	(2)	(9)
Total provision for PILs	109	121
Effective income tax rate	11.98%	13.96%

The current provision for PILs is remitted to, or received from, the Ontario Electricity Financial Corporation (OEFC). At December 31, 2013, $29 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (December 31, 2012 – $10 million included in due to related parties).

The total provision for PILs includes deferred recovery of PILs of $2 million (2012 – $9 million) that is not included in the rate-setting process, using the liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, 2013 and 2012, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	7	7
Environmental expenditures	5	4
Depreciation and amortization in excess of capital cost allowance	–	3
Other	(1)	–
Total deferred income tax assets	11	14
Less: current portion	–	–
	11	14

December 31 (millions of Canadian dollars)	**2013**	**2012**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,556)	(1,344)
Post-retirement and post-employment benefits expense in excess of cash payments	542	519
Environmental expenditures	66	62
Regulatory amounts that are not recognized for tax purposes	(144)	(147)
Goodwill	(20)	(19)
Other	1	3
Total deferred income tax liabilities	(1,111)	(926)
Less: current portion	18	18
	(1,129)	(944)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $60 million increase).

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	2013	2012
Accounts receivable – billed	268	224
Accounts receivable – unbilled	691	644
Accounts receivable, gross	959	868
Allowance for doubtful accounts	(36)	(23)
Accounts receivable, net	923	845

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	2013	2012
Allowance for doubtful accounts – January 1	(23)	(18)
Write-offs	24	17
Additions to allowance for doubtful accounts	(37)	(22)
Allowance for doubtful accounts – December 31	(36)	(23)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,413	4,215	671	8,869
Distribution	8,498	3,046	316	5,768
Communication	1,060	560	53	553
Administration and Service	1,380	716	38	702
Easements	617	78	–	539
	23,968	8,615	1,078	16,431

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	11,840	3,990	641	8,491
Distribution	8,005	2,879	234	5,360
Communication	1,024	516	57	565
Administration and Service	1,314	668	123	769
Easements	614	92	–	522
	22,797	8,145	1,055	15,707

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2013 (2012 – $56 million).

10. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	557	249	3	311
Other	5	3	–	2
	562	252	3	313

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	451	301	116	266
Other	5	4	–	1
	456	305	116	267

Financing charges capitalized on intangible assets under development were $3 million in 2013 (2012 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2014 – $52 million; 2015 – $52 million; 2016 – $52 million; 2017 – $52 million; and 2018 – $44 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Regulatory assets:		
Deferred income tax regulatory asset	1,145	954
Pension benefit regulatory asset	845	1,515
Post-retirement and post-employment benefits	308	320
Environmental	266	249
Pension cost variance	80	61
OEB cost assessment differential	9	6
DSC exemption	7	2
Long-term project development costs	5	5
Rider 2	–	10
Other	18	5
Total regulatory assets	2,683	3,127
Less: current portion	47	29
	2,636	3,098
Regulatory liabilities:		
External revenue variance	81	61
Rider 8	55	45
Retail settlement variance accounts	35	54
Deferred income tax regulatory liability	19	16
Rider 9	19	–
PST savings deferral	17	13
Hydro One Brampton Networks rider	8	–
Rider 3	–	9
Rural and remote rate protection variance	–	6
Other	14	17
Total regulatory liabilities	248	221
Less: current portion	85	40
	163	181

Deferred Income Tax Regulatory Asset and Liability

Deferred 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 profit. The Company has recognized regulatory assets and liabilities that correspond to deferred 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 2013 provision for PILs would have been higher by approximately $139 million (2012 – $136 million).

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $670 million (2012 – lower by $736 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2013 OCI would have been higher by $12 million (2012 – lower by $197 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2013, the environmental regulatory asset decreased by $3 million (2012 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $26 million (2012 – $2 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2013 operation, maintenance and administration expenses would have been higher by $23 million (2012 – lower by $1 million). In addition, 2013 amortization expense would have been lower by $16 million (2012 – $18 million), and 2013 financing charges would have been higher by $10 million (2012 – $11 million).

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $19 million (2012 – $18 million).

OEB Cost Assessment Differential

In April 2010, the OEB announced its decision regarding the Company's rate application in respect of Hydro One Networks' distribution business for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments.

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One

Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that expenditures for identified specific expenditures can be recorded in a deferral account, subject to the OEB's review at a future date.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

Rider 2

In April 2006, the OEB approved Hydro One Networks' distribution-related deferral account balances. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of the Rider 2 regulatory account for disposition as part of Rider 9, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. Hydro One has continued to accumulate a net liability in its RSVAs since December 31, 2011.

Rider 9

In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account, per direction from the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2013 and recorded in a deferral account, per direction from the OEB.

Hydro One Brampton Networks Rider

In December 2013, the OEB issued a decision for Hydro One Brampton Networks' 2014 distribution rates. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from January 1, 2014 to December 31, 2015.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of Rider 2 for disposition as part of Rider 9.

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 Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account. At December 31, 2013, the RRRP variance account had a $2 million debit balance, which is included in Other regulatory assets.

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2013 and 2012.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2018. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and supports the Company's Commercial Paper Program. The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2013, $1,815 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	**2012**
5.00% Series 15 notes due 2013	–	600
3.13% Series 19 notes due 2014[1]	750	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	50
5.18% Series 13 notes due 2017	600	600
2.78% Series 28 notes due 2018	750	–
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	600
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	–
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
	9,045	8,460
Add: Unrealized marked-to-market loss[1]	12	19
Less: Long-term debt payable within one year	(756)	(600)
Long-term debt	8,301	7,879

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $12 million (2012 – $19 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 13 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2013, Hydro One issued $1,185 million (2012 – $1,085 million) of long-term debt under the MTN Program, and repaid the $600 million MTN Series 15 notes (2012 – redeemed $600 million MTN Series 3 notes).

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 13 – Fair Value of Financial Instruments and Risk Management.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2013 and 2012, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2013 and 2012 are as follows:

December 31 (millions of Canadian dollars)	2013 Carrying Value	2013 Fair Value	2012 Carrying Value	2012 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	506	506	512	512
$250 million of MTN Series 21 notes[2]	256	256	257	257
Other notes and debentures[3]	8,295	9,018	7,710	9,188
	9,057	9,780	8,479	9,957

[1] The fair value of $500 million of the MTN Series 19 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2013, the Company had interest-rate swaps totaling $750 million (2012 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 8% (2012 – 9%) of its total long-term debt of $9,057 million (2012 – $8,479 million). At December 31, 2013, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the $750 million MTN Series 19 notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2013, the Company also had interest-rate swaps with a total notional value of $900 million (2012 – $900 million) classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2013 to December 11, 2014, from February 19, 2013 to February 19, 2014, and from February 19, 2014 to November 19, 2014;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2013 to January 24, 2014, and from January 24, 2014 to January 24, 2015; and

(e) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from December 3, 2013 to December 3, 2014.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 is as follows:

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	565	565	565	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	12	12	–	12	–
	828	828	565	263	–
Liabilities:					
Bank indebtedness	31	31	31	–	–
Long-term debt	9,057	9,780	–	9,780	–
	9,088	9,811	31	9,780	–

December 31, 2012 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	195	195	195	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	–	19	–
	465	465	195	270	–
Liabilities:					
Bank indebtedness	42	42	42	–	–
Long-term debt	8,479	9,957	–	9,957	–
	8,521	9,999	42	9,957	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2013, short-term investments consisted of bankers' acceptances and money market funds totaling $515 million (2012 – $195 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment represents the Province of Ontario Floating-Rate Notes maturing in November 2014. The fair value of the investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2013 and 2012.

Risk Management

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 capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Transmission and Distribution Businesses is derived using a formulaic approach that 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 forecasted 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 the Transmission Business' annual results of operations by approximately $19 million (2012 – $18 million) and Hydro One Networks' distribution business' annual results of operations by approximately $10 million (2012 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were in existence as at December 31, 2013 or 2012.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2013 or 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2013 and 2012 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Unrealized loss (gain) on hedged debt	(8)	(14)
Unrealized loss (gain) on fair value interest-rate swaps	8	14
Net unrealized loss (gain)	–	–

At December 31, 2013, Hydro One had $750 million (2012 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $12 million (2012 – $19 million). During the years ended December 31, 2013 and 2012, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2013 and 2012, 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, Hydro One did not earn a significant amount of revenue from any single customer. At December 31, 2013 and 2012, there was no significant accounts receivable balance due from any single customer.

At December 31, 2013, the Company's provision for bad debts was $36 million (2012 – $23 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 4% of the Company's net accounts receivable were aged more than 60 days (2012 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company'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. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive marked-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2013, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $14 million (2012 – $22 million). At December 31, 2013, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of three of the four counterparties accounted for more than 10% of the total credit exposure of derivative contracts.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility of $1,500 million, and by holding Province of Ontario Floating-Rate Notes. The short-term liquidity under the Commercial Paper Program, the holding of Province of Ontario Floating-Rate Notes and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2013, accounts payable and accrued liabilities in the amount of $795 million (2012 – $722 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2013, Hydro One had issued long-term debt in the principal amount of $9,045 million (2012 – $8,460 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 Long-term Debt** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	750	422	3.1
2 years	550	398	2.8
3 years	500	372	4.3
4 years	600	361	5.2
5 years	750	330	2.8
	3,150	1,883	3.6
6 – 10 years	900	1,470	3.6
Over 10 years	4,995	4,281	5.5
	9,045	7,634	4.7

14. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2013 and 2012, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Long-term debt payable within one year	756	600
Less: cash and cash equivalents	565	195
	191	405
Long-term debt	8,301	7,879
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	3,787	3,202
	7,101	6,516
Total capital	15,916	15,123

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2013 and 2012, Hydro One was in compliance with all of these covenants and limitations.

15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. Employees of Hydro One Brampton Networks participate in the OMERS plan, a multiemployer public sector pension fund. The supplementary pension plan provides members of the

Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2013 were $2 million (2012 – $2 million). Company contributions payable at December 31, 2013 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2012 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2012.

At December 31, 2012, the OMERS plan was 85.6% funded, with an unfunded liability of $9,924 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The 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 Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2013 of $160 million (2012 – $163 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2013 pensionable earnings. Estimated annual Pension Plan contributions for 2014 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	6,507	5,461	1,459	1,206
Current service cost	170	123	40	29
Interest cost	278	285	63	63
Reciprocal transfers	1	1	–	–
Benefits paid	(317)	(291)	(44)	(42)
Net actuarial loss (gain)	(63)	928	13	203
Projected benefit obligation, end of year	6,576	6,507	1,531	1,459
Change in plan assets				
Fair value of plan assets, beginning of year	4,992	4,682	–	–
Actual return on plan assets	887	425	–	–
Reciprocal transfers	1	1	–	–
Benefits paid	(317)	(291)	–	–
Employer contributions	160	163	–	–
Employee contributions	30	27	–	–
Administrative expenses	(22)	(15)	–	–
Fair value of plan assets, end of year	5,731	4,992	–	–
Unfunded status	845	1,515	1,531	1,459

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Accrued liabilities	–	–	43	43
Pension benefit liability	845	1,515	–	–
Post-retirement and post-employment benefit liability	–	–	1,488	1,416
Unfunded status	845	1,515	1,531	1,459

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 (millions of Canadian dollars)	**2013**	**2012**
PBO	6,576	6,507
ABO	5,998	6,074
Fair value of plan assets	5,731	4,992

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2013 (2012 – 82%). On a PBO basis, the Pension Plan was funded at 87% at December 31, 2013 (2012 – 77%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2013 and 2012 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current service cost, net of employee contributions	141	96
Interest cost	278	285
Expected return on plan assets, net of expenses	(309)	(289)
Actuarial loss amortization	175	112
Prior service cost amortization	2	3
Net periodic benefit costs	287	207
Charged to results of operations[1]	72	76

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2013, pension costs of $160 million (2012 – $163 million) were attributed to labour, of which $72 million (2012 – $76 million) was charged to operations, and $88 million (2012 – $87 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2013 and 2012 for the post-retirement and post-employment plans:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Current service cost, net of employee contributions	40	30
Interest cost	63	63
Actuarial loss amortization	27	8
Prior service cost amortization	3	3
Net periodic benefit costs	133	104
Charged to results of operations	58	48

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2013 and 2012:

Year ended December 31	Pension Benefits 2013	Pension Benefits 2012	Post-Retirement and Post-Employment Benefits 2013	Post-Retirement and Post-Employment Benefits 2012
Significant assumptions:				
Weighted average discount rate	4.75%	4.25%	4.75%	4.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	–	–	4.39%	4.39%

[1] 6.81% per annum in 2014, grading down to 4.39% per annum in and after 2031 (2012 – 6.91% in 2013, grading down to 4.39% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2013 and 2012. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2013	2012
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.25%	6.25%
Weighted average discount rate	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11
Post-retirement and Post-Employment Benefits:		
Weighted average discount rate	4.25%	5.25%
Rate of compensation scale escalation (without merit)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	11	11
Rate of increase in health care cost trends[1]	4.39%	4.41%

[1] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2012 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2013 and 2012 is as follows:

December 31 (millions of Canadian dollars)	2013	2012
Projected benefit obligation:		
Effect of 1% increase in health care cost trends	258	246
Effect of 1% decrease in health care cost trends	(200)	(191)

The effect of 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2013 and 2012 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Service cost and interest cost:		
Effect of 1% increase in health care cost trends	21	17
Effect of 1% decrease in health care cost trends	(16)	(13)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2013 and 2012:

December 31, 2013				**December 31, 2012**			
Life expectancy at 65 for a member currently at				**Life expectancy at 65 for a member currently at**			
Age 65		**Age 45**		**Age 65**		**Age 45**	
Male	Female	Male	Female	Male	Female	Male	Female
23	25	24	26	20	22	21	23

Estimated Future Benefit Payments

At December 31, 2013, estimated future benefit payments by the Company to Plan participants were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2014	310	54
2015	319	57
2016	327	59
2017	335	62
2018	343	65
2019 through to 2023	1,698	370
Total estimated future benefit payments through to 2023	3,332	667

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Pension Benefits:		
Actuarial loss (gain) for the year	(619)	807
Actuarial loss amortization	(175)	(112)
Prior service cost amortization	(2)	(3)
	(796)	692
Post-Retirement and Post-Employment Benefits:		
Actuarial loss for the year	13	203
Actuarial loss amortization	(27)	(8)
Prior service cost amortization	(3)	(3)
	(17)	192

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Pension Benefits:		
Prior service cost	3	5
Actuarial loss	842	1,510
	845	1,515
Post-Retirement and Post-Employment Benefits:		
Prior service cost	2	5
Actuarial loss	306	315
	308	320

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2013**	**2012**	**2013**	**2012**
Prior service cost	2	2	2	3
Actuarial loss	103	175	15	17
	105	177	17	20

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Investment-Pension Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2013, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	67.8
Debt securities	35.0	32.2
Other [1]	5.0	0.0
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2013, the Pension Plan held $15 million of Hydro One corporate bonds (2012 – $20 million) and $217 million of debt securities of the Province (2012 – $243 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2013 and 2012. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2013 and 2012, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "A+" by Standard and Poor's, Dominion Bond Rating Service, and Fitch Ratings, and "A1" by Moody's Investors Service Inc., and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2013 and 2012:

December 31, 2013 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	1	16	117	134
Cash and cash equivalents	150	–	–	150
Short-term securities	–	180	–	180
Real estate	–	–	2	2
Corporate shares – Canadian	943	–	–	943
Corporate shares – Foreign	2,708	–	–	2,708
Bonds and debentures – Canadian	–	1,416	–	1,416
Bonds and debentures – Foreign	–	186	–	186
Total fair value of plan assets[1]	3,802	1,798	119	5,719

[1] At December 31, 2013, the total fair value of Pension Plan assets excludes $19 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

December 31, 2012 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	2	15	104	121
Cash and cash equivalents	125	–	–	125
Short-term securities	–	100	–	100
Real estate	–	–	2	2
Corporate shares – Canadian	920	–	–	920
Corporate shares – Foreign	2,077	–	–	2,077
Bonds and debentures – Canadian	–	1,643	–	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions, and $8 million relating to accruals for pension administration expense.

See Note 13 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2013 and 2012. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of Canadian dollars)	**2013**	**2012**
Fair value, beginning of year	106	167
Realized and unrealized gains	23	5
Purchases	–	6
Sales and disbursements	(10)	(72)
Fair value, end of year	119	106

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2013 and 2012:

Year ended December 31, 2013 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	197	52	249
Interest accretion	9	1	10
Expenditures	(2)	(14)	(16)
Revaluation adjustment	(3)	26	23
Environmental liabilities, December 31	201	65	266
Less: current portion	15	12	27
	186	53	239

Year ended December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	199	58	257
Interest accretion	9	2	11
Expenditures	(8)	(10)	(18)
Revaluation adjustment	(3)	2	(1)
Environmental liabilities, December 31	197	52	249
Less: current portion	13	9	22
	184	43	227

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2013 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	237	68	305
Less: discounting accumulated liabilities to present value	36	3	39
Discounted environmental liabilities	201	65	266

December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	233	54	287
Less: discounting accumulated liabilities to present value	36	2	38
Discounted environmental liabilities	197	52	249

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	27
2015	28
2016	35
2017	23
2018	22
Thereafter	170
	305

At December 31, 2013, of the total estimated future environmental expenditures, $237 million relates to PCBs (2012 – $233 million) and $68 million relates to LAR (2012 – $54 million).

Hydro One records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. 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. 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 rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. In addition, with respect to the PCB environmental liability, 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. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting the expectation that future environmental costs will be recoverable in rates.

PCBs

In September 2008, Environment Canada published regulations governing the management, storage and disposal of PCBs, enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under these regulations and Hydro One's approved end-of-use extension, PCBs in concentrations of 500 parts per million (ppm) or more have to be disposed of by the end of 2014, with the exception of specifically exempted equipment, and PCBs 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. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $237 million. These expenditures are expected to be incurred over the period from 2014 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to reduce the PCB environmental liability by $3 million (2012 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $68 million. These expenditures are expected to be incurred over the period from 2014 to 2022. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $26 million (2012 – $2 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for 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 approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's AROs represent management's best estimates of the 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 Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2013, Hydro One had recorded AROs of $14 million (2012 – $15 million), consisting of $7 million (2012 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $7 million (2012 – $8 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal and there have been no significant expenditures associated with these obligations in 2013.

18. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of Shareholder's Equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2013. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

19. DIVIDENDS

In 2013, preferred share dividends in the amount of $18 million (2012 – $18 million) and common share dividends in the amount of $200 million (2012 – $352 million) were declared.

20. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues include $1,509 million (2012 – $1,474 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2012 – $127 million) related to this program. Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $33 million (2012 – $28 million) related to these services.

In 2013, Hydro One purchased power in the amount of $2,477 million (2012 – $2,392 million) from the IESO-administered electricity market; $15 million (2012 – $10 million) from OPG; and $8 million (2012 – $7 million) from power contracts administered by 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 transmitters. In 2013, Hydro One incurred $12 million (2012 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2013, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $9 million (2012 – $10 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $1 million in 2013 (2012 – $2 million).

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2013, Hydro One received $34 million (2012 – $39 million) from the OPA related to these programs.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

PILs and payments in lieu of property taxes are paid to the OEFC, and dividends are paid to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

At December 31, 2013, the Company held $250 million in Province of Ontario Floating-Rate Notes with a fair value of $251 million (2012 – $251 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of Canadian dollars)	2013	2012
Due from related parties	197	154
Due to related parties[1]	(230)	(261)
Investment	251	251

[1] Included in due to related parties at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $217 million (2012 – $199 million).

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of Canadian dollars)	2013	2012
Accounts receivable	(78)	(30)
Due from related parties	(43)	2
Materials and supplies	–	2
Other assets	(5)	(4)
Accounts payable	(60)	(5)
Accrued liabilities	150	10
Due to related parties	(31)	(85)
Accrued interest	5	10
Long-term accounts payable and other liabilities	(11)	13
Post-retirement and post-employment benefit liability	84	56
	11	(31)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	2013	2012
Capital investments in property, plant and equipment	(1,312)	(1,363)
Net change in accruals included in capital investments in property, plant and equipment	(21)	(10)
Capital expenditures – property, plant and equipment	(1,333)	(1,373)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	2013	2012
Capital investments in intangible assets	(82)	(91)
Net change in accruals included in capital investments in intangible assets	3	1
Capital expenditures – intangible assets	(79)	(90)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	2013	2012
Net interest paid	395	411
PILs	138	197

22. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

23. COMMITMENTS

Agreement with Inergi LP (Inergi)

In 2002, Inergi, an affiliate of Capgemini Canada Inc., began providing services to Hydro One, including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The current agreement with Inergi will expire in February 2015.

At December 31, 2013, the annual commitments under the Inergi agreement are as follows: 2014 – $130 million; 2015 – $22 million; 2016 and thereafter – nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2013, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton Networks using parental guarantees of $325 million (2012 – $325 million), and on behalf of two distributors using guarantees of $1 million (2012 – $1 million). In addition, as at December 31, 2013, the Company has provided letters of credit in the amount of $21 million (2012 – $22 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2013, Hydro One had letters of credit of $127 million (2012 – $127 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Within one year	11	10
After one year but not more than five years	28	29
More than five years	9	14
	48	53

During the year ended December 31, 2013, the Company made lease payments totaling $11 million (2012 – $9 million).

24. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2013 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,529	4,484	61	6,074
Purchased power	–	3,020	–	3,020
Operation, maintenance and administration	375	672	59	1,106
Depreciation and amortization	327	340	9	676
Income (loss) before financing charges and provision for PILs	827	452	(7)	1,272
Financing charges				360
Income before provision for PILs				912
Capital investments	714	673	7	1,394

Year ended December 31, 2012 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	1,482	4,184	62	5,728
Purchased power	–	2,774	–	2,774
Operation, maintenance and administration	402	608	61	1,071
Depreciation and amortization	320	329	10	659
Income (loss) before financing charges and provision for PILs	760	473	(9)	1,224
Financing charges				358
Income before provision for PILs				866
Capital investments	776	671	7	1,454

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2013**	**2012**
Total assets		
Transmission	11,846	11,586
Distribution	8,805	8,621
Other	974	604
	21,625	20,811

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. SUBSEQUENT EVENT

On January 29, 2014, Hydro One issued $50 million notes under its MTN Program, with a maturity date of January 29, 2064 and a coupon rate of 4.29%.

HYDRO ONE INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited pro forma condensed consolidated financial statements are presented to reflect the impact of certain of the transactions described under “Pre-Closing Transactions”. The unaudited pro forma condensed consolidated financial statements should be read together with the notes to the unaudited pro forma condensed consolidated financial statements.

HYDRO ONE INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
At June 30, 2015

	Hydro One Inc.	Payment of Departure Tax	*Note*	Deferred Tax Benefit	*Note*	Recapitalization	*Note*	Hydro One Brampton	*Note*	Hydro One Inc. Pro Forma
	(millions of Canadian dollars)									
Assets										
Current assets:										
Cash and cash equivalents	270	(2,600) 2,600	2A 2B	(200)	2C (iii)	800 (800)	2D 2E	(28) (24)	2I, 2J (i) 2J (iii)	18
Accounts receivable	1,013	—		—		—		(78)	2J (i)	935
Due from related parties	177	—		—		—		—		177
Regulatory assets	43	—		—		—		—		43
Materials and supplies	26	—		—		—		(1)	2J (i)	25
Deferred income tax assets	19	—		—		—		—		19
Derivative instruments	1	—		—		—		—		1
Prepaid expenses and other assets	35	—		—		—		(1)	2J (i)	34
	1,584	—		(200)		—		(132)		1,252
Property, plant and equipment:										
Property, plant and equipment in service	25,886	—		—		—		(609)	2J (i)	25,277
Less: accumulated depreciation	(9,398)	—		—		—		292	2J (i)	(9,106)
	16,488	—		—		—		(317)		16,171
Construction in progress	1,258	—		—		—		(12)	2J (i)	1,246
Future use land, components and spares	161	—		—		—		(5)	2J (i)	156
	17,907	—						(334)		17,573
Other long-term assets:				—		—				
Regulatory assets	3,170	—		—		—		(1)	2J (i)	3,169
Intangible assets	258	—		—		—		(13)	2J (i)	245
Goodwill	199	—		—		—		(60)	2J (i)	139
Deferred income tax assets	6	—		200 1,245	2C (iii) 2C (ii)	—		—		1,451
Deferred debt issuance costs	36	—		—		—		(1)	2J (i)	35
Other	7	—		—		—		—		7
	3,676	—		1,445		—		(75)		5,046
Total assets	**23,167**	**—**		**1,245**		**—**		**541)**		**23,871**

See accompanying notes to Unaudited Pro Forma Condensed Consolidated Financial Statements.

HYDRO ONE INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET (continued)
At June 30, 2015

	Hydro One Inc.	Payment of Departure Tax	*Note*	Deferred Tax Benefit	*Note*	Recapitalization	*Note*	Hydro One Brampton	*Note*	Hydro One Inc. Pro Forma
					(millions of Canadian dollars)					
Liabilities										
Current liabilities										
Accounts payable	184	—		—		—		(4)	2J (i)	180
Regulatory liabilities	18	—		—		—		—		18
Accrued interest	99	—		—		—		(1)	2J (i)	98
Accrued liabilities	639	—		—		—		(69)	2J (i)	570
Due to related parties	52	—		—		—		—		52
Income tax payable	—	—		—		—		—		—
Derivative instruments	3	—		—		—		—		3
Long term debt payable within one year	1,017	—		—		—		—		1,017
	2,012	—		—		—		(74)		1,938
Long-term debt	8,273	—		—		800	2D	—		9,073
Other long-term liabilities:										
Pension benefit liability	1,228	—		—		—		—		1,228
Post-retirement and post-employment benefit liability	1,569	—		—		—		(5)	2J (i)	1,564
Regulatory liabilities	200	—		—		—		1	2J (i)	201
Deferred income tax liabilities	1,380	—		(1,355)	2C (i)	—		(12)	2J (i)	13
Environmental liabilities	207	—		—		—		—		207
Net unamortized debt premiums	18	—		—		—		—		18
Asset retirement obligations	9	—		—		—		—		9
Long-term accounts payable and other liabilities	14	—		—		—		(1)	2J (i)	13
	4,625	—		(1,355)		—		(17)		3,253
Total liabilities	**14,910**	**—**		**(1,355)**		**800**		**(91)**		**14,264**
Preferred shares	323	—		—		(323)	2H	—		—
Noncontrolling interest	21	—		—		—		—		21
Equity										
Common shares	3,314	2,600	2B	—		323	2H	(193)	2J (ii)	6,044
				1,355	2C(i)			(233)	2I, 2J (i)	
Retained earnings	4,558	(2,600)	2A	1,245	2C(ii)	(800)	2E	(24)	2J (iii)	3,501
Accumulated other comprehensive loss	(9)	—		—		—		—		(9)
Noncontrolling interest	50	—		—		—		—		50
Total equity	**7,913**	—		**2,600**		**(477)**		**(450)**		**9,586**
	23,167	—		**1,245**		**—**		**(541)**		**23,871**

See accompanying notes to Unaudited Pro Forma Condensed Consolidated Financial Statements.

HYDRO ONE INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME

For the six months ended June 30, 2015

	Hydro One Inc.	Payment of Departure Tax	*Note*	Deferred Tax Benefit	*Note*	Recapitalization	*Note*	Hydro One Brampton	*Note*	Hydro One Inc. Pro Forma
	(millions of Canadian dollars, except per share amounts)									
Revenues										
Distribution	2,574	—		—		—		(254)	2J (i)	2,320
Transmission	770	—		—		—		—		770
Other	27	—		—		—		—		27
	3,371	—		—		—		(254)		3,117
Costs										
Purchased power	1,808	—		—		—		(218)	2J (i)	1,590
Operating costs:										
Operation, maintenance and administration	560	—		—		—		(14)	2J (i)	546
Depreciation and amortization	377	—		—		—		(9)	2J (i)	368
	2,745	—		—		—		(241)		2,504
Net income before financing charges and provision for payments in lieu of corporate income taxes	**626**	—		—		—		**(13)**		**613**
Financing charges	187	—		—		12	2F	(6)	2J (i)	193
Net income before provision for payments in lieu of corporate income taxes	**439**	**—**		**—**		**(12)**		**(7)**		**420**
				(60)	2C (iv)					
				60	2C (iv)					
				11	2C (v)					
Provision for payments in lieu of corporate income taxes	68	—		(11)	2C (v)	(3)	2G	(1)	2J (i)	64
Net income and comprehensive income	**371**	**—**		**—**		**(9)**		**(6)**		**356**
Net income and comprehensive income attributable to noncontrolling interest	3	—		—		—		—		3
Net income and comprehensive income attributable to the shareholder of Hydro One	**368**	**—**		**—**		**(9)**		**(6)**		**353**
Earnings per common share *(Canadian dollars)*										
Basic	**3,594**									**2,426**
Diluted	**3,594**									**2,426**

See accompanying notes to Unaudited Pro Forma Condensed Consolidated Financial Statements.

HYDRO ONE INC.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME

For the year ended December 31, 2014

	Hydro One Inc.	Payment of Departure Tax	*Note*	Deferred Tax Benefit	*Note*	Recapitalization	*Note*	Hydro One Brampton	*Note*	Hydro One Inc. Pro Forma
	(millions of Canadian dollars, except per share amounts)									
Revenue										
Distribution	4,903	—		—		—		(495)	2J (i)	4,408
Transmission	1,588	—		—		—		—		1,588
Other	57	—		—		—		—		57
	6,548	—		—		—		(495)		6,053
Costs										
Purchased power	3,419	—		—		—		(426)	2J (i)	2,993
Operating costs										
Operation, maintenance and administration	1,192	—		—		—		(27)	2J (i)	1,165
Depreciation and amortization	722	—		—		—		(14)	2J (i)	708
	5,333	—		—		—		(467)		4,866
Net income before financing charges and provision for payments in lieu of corporate income taxes	**1,215**	**—**		**—**		**—**		**(28)**		**1,187**
Financing charges	379	—		—		24	2F	(11)	2J (i)	392
Net income before provision or payments in lieu of corporate income taxes	**836**	**—**		**—**		**(24)**		**(17)**		**795**
Provision for payments in lieu of corporate income taxes	89	2,600	2A	(1,355) (1,245) (77) 77 21 (21)	2C (i) 2C (ii) 2C (iv) 2C (iv) 2C (v) 2C (v)	(6)	2G	(3) 7	2J (i) 2J (iii)	87
Net income and comprehensive income	**747**	**(2,600)**		**2,600**		**(18)**		**(21)**		**708**
Net income and comprehensive income attributable to noncontrolling interest	(2)	—		—		—		—		(2)
Net income and comprehensive income attributable to the shareholder of Hydro One	**749**	**(2,600)**		**2,600**		**(18)**		**(21)**		**710**
Earnings per common share *(Canadian dollars)*										
Basic	**7,319**									**4,880**
Diluted	**7,319**									**4,880**

See accompanying notes to Unaudited Pro Forma Condensed Consolidated Financial Statements.

HYDRO ONE INC.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

These unaudited pro forma condensed consolidated financial statements of Hydro One Inc. have been prepared for illustrative purposes only by management for inclusion in the prospectus (the "**Prospectus**") of Hydro One Limited dated October 28, 2015 relating to the proposed secondary offering (the "**Offering**") by the Province of Ontario (the "**Province**") of common shares of Hydro One Limited. Prior to the completion of the Offering, Hydro One Inc. will repurchase or redeem the preferred shares of Hydro One Inc. currently held by the Province in exchange for common shares, and Hydro One Limited will acquire all of the issued and outstanding common shares of Hydro One Inc. in return for common shares and preferred shares of Hydro One Limited. References herein to "**Hydro One**" refer to Hydro One Inc. and its consolidated subsidiaries, but do not include or refer to Hydro One Limited.

These unaudited pro forma condensed consolidated financial statements of Hydro One Inc. are presented to reflect the expected impact of the transactions described in note 2 as if those transactions occurred as at June 30, 2015 with respect of the unaudited pro forma condensed consolidated balance sheet as at June 30, 2015, and as if these transactions occurred on January 1, 2014 with respect of the unaudited pro forma condensed consolidated statements of operations for the six month period ended June 30, 2015 and for the year ended December 31, 2014. These transactions relate to the following events:

- the payment by Hydro One Inc. and certain of its subsidiaries of the Departure Tax (as defined in note 2A);
- the recognition by Hydro One Inc. of a deferred income tax asset as a consequence of leaving the PILs (as defined in note 2A) regime and entering the corporate tax regime;
- the recapitalization of Hydro One Networks Inc.; and
- the transfer of all of the issued and outstanding shares of Hydro One Brampton Networks Inc. (**Hydro One Brampton**) by Hydro One Inc. to a company wholly-owned by the Province.

These unaudited pro forma condensed consolidated financial statements have been prepared based on the historical unaudited consolidated interim financial statements of Hydro One Inc. as at and for the six month period ended June 30, 2015 and the audited consolidated financial statements of Hydro One Inc. for the year ended December 31, 2014, together with the notes accompanying such financial statements, included elsewhere in the Prospectus. As such, this unaudited pro forma condensed consolidated balance sheet and these unaudited pro forma condensed consolidated statements of operations and comprehensive income should be read in conjunction with the Hydro One Inc. consolidated financial statements.

The Hydro One Inc. historical consolidated financial statements have been adjusted in the unaudited pro forma condensed consolidated financial statements to give effect to events that are (i) directly attributable to the pro forma events, (ii) factually supportable, and (iii) with respect to the statement of operations, expected to have a continuing impact on the combined company. These unaudited pro forma condensed consolidated financial statements do not reflect any non-recurring charges directly related to the pro forma events that may be incurred upon completion of the transactions.

The unaudited pro forma condensed consolidated financial statements are presented solely for informational purposes and are not necessarily indicative of the results that would have occurred had the transactions been completed at the dates indicated, nor are they necessarily indicative of future operating results or the financial position of Hydro One Inc. or Hydro One Limited.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

A. In connection with the Offering, Hydro One's exemption from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) will cease to apply. Under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), Hydro One will be deemed to have disposed of its assets immediately before it loses its tax exempt status for proceeds equal to the fair market value of those assets at that time. Hydro One will be liable to make a payment in lieu of tax ("**PILs**") under the *Electricity Act, 1998* (Ontario) (the "**Electricity Act**") in respect of the income and capital gains, calculated by reference to the *Income Tax Act* (Canada), that arise as a result of this deemed disposition. The amount payable is generally referred to as "**Departure Tax**". In the context of a public offering of shares, and with the consent of the Minister of Finance, Hydro One will be authorized to pay to the Ontario Electricity Financial Corporation an amount that, in the Minister's opinion, reasonably approximates the amount of the Departure Tax that would be payable by Hydro One in respect of the deemed disposition of its assets. Hydro One has received a letter from the Minister of Finance confirming that the total amount of the Departure Tax payable by Hydro One, together with Hydro One Limited, is $2.6 billion.

B. To enable Hydro One Inc. to make the Departure Tax payment, Hydro One Limited will subscribe for 2.6 billion additional common shares of Hydro One Inc. for $2,600 million. Hydro One Inc. will use the proceeds of this share subscription to pay its portion of the Departure Tax payable and will use the remaining proceeds to subscribe for additional shares of certain subsidiaries of Hydro One Inc. in order to allow those subsidiaries to pay their respective portions of the Departure Tax payable. The $2,600 million adjustment reflects the proceeds of this subscription.

C. The following additional adjustments result from Hydro One leaving the PILs regime and entering the corporate tax regime:

(i) Reversal of $1,355 million of an existing deferred income tax liability for taxable temporary differences that were attributable to differences between the carrying amount of assets and liabilities and their corresponding lower tax basis prior to leaving the PILs regime and entering the corporate tax regime.

(ii) Establishment of a deferred income tax asset of $1,245 million for deductible temporary differences that are attributable to differences between the excess of tax basis over the corresponding carrying amount of assets and liabilities upon Hydro One leaving the PILs regime and entering the corporate tax regime.

This calculation of the deferred tax asset adjustment has been based on an estimated fair market value of Hydro One's net assets of approximately $13,522 million, which was the same estimated fair market value used for the purposes of determining the departure tax amount of $2.6 billion referred to in note 2A. The actual fair market value of Hydro One's net assets will be determined following pricing of this offering. The departure tax payable by Hydro One has been fixed at $2.6 billion, and will not be adjusted based on the fair market value of Hydro One's net assets as finally determined. The Company estimates that a $1,000 million increase or decrease in the fair market value of Hydro One's net assets would result in a corresponding increase or decrease in the deferred tax asset, and therefore net income, of approximately $200 million. See "Summary Consolidated Financial Information" and "Selected Consolidated Financial Information".

(iii) Additional cash PILs estimated at $200 million resulting from Hydro One Inc. being unable to claim Capital Cost Allowance ("**CCA**") in the year of deemed disposition of assets with a corresponding increase in deferred income tax assets that reflects the ability to claim that CCA in a future tax year.

(iv) Reduction in cash PILs of $77 million and $60 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively. This is offset by the release of a deferred income tax asset of $77 million and $60 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively.

(v) Payment of Corporate Minimum Tax of $21 million and $11 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively. This is offset by a deferred tax benefit of $21 million and $11 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively.

(vi) The reduction in cash PILs in note 2C(iv) and pro forma payment of Corporate Minimum Tax in note 2C(v) result in a net pro forma reduction in cash tax for the year ended December 31, 2014 of $56 million and for the six month period ended June 30, 2015 of $49 million, for a total reduction in cash tax of $105 million for the period from January 1, 2014 to June 30, 2015 as outlined in the following table:

	Six month period ended June 30, 2015	**Year ended December 31, 2014**
	(millions of Canadian dollars)	
Reduction in Cash PILs	60	77
Pro forma corporate minimum tax	(11)	(21)
Total	49	56

D. The $800 million adjustment represents the amount borrowed by Hydro One Inc. either through the issuance of commercial paper, borrowings under its existing committed revolving standby credit facility, or borrowings under a new revolving term credit facility to be entered into by Hydro One Inc. prior to the closing of the Offering (the "**New Debt**").

E. The $800 million adjustment represents the proposed $800 million dividend or return of capital paid by Hydro One Inc. to the Province.

F. The adjustments of $24 million and $12 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively, represent the interest paid under the terms of the New Debt described in note 2D.

G. The adjustment of $6 million and $3 million for the year ended December 31, 2014 and six month period ended June 30, 2015, respectively, reflects the tax impact of the interest paid under the terms of the New Debt described in note 2D.

H. The adjustment of $323 million reflects the purchase or redemption for cancellation by Hydro One Inc. of all of the issued and outstanding preferred shares of Hydro One Inc. held by the Province in exchange for the issuance of common shares of Hydro One Inc. to the Province.

I. The adjustment represents the subscription by Hydro One Inc. for common shares of Hydro One Brampton for an aggregate subscription price of approximately $50 million.

J. The following are the adjustments made to the unaudited pro forma condensed consolidated financial statements in relation to the transaction involving Hydro One Brampton:

(i) The adjustments reflect the carve out of Hydro One Brampton financial information as a result of the transfer of all of the issued and outstanding shares of Hydro One Brampton as a dividend-in-kind paid by Hydro One Inc. to a company wholly-owned by the Province, as directed by the Province.

(ii) The adjustment reflects the transfer of a note receivable owing from Hydro One Brampton in the aggregate principal amount of $193 million to a company wholly-owned by the Province as a return of capital, as directed by the Province.

(iii) For the purposes of the pro forma condensed consolidated balance sheet, the adjustment of $24 million reflects payment of capital gains tax due to the transfer of the note receivable of $193 million as described in note 2J(ii) as well as transfer of all of the issued and outstanding shares of Hydro One Brampton as described in note 2J(i). For the purposes of the pro forma condensed consolidated statement of operations for the year ended December 31, 2014, the adjustment of $7 million reflects the tax expense of the difference between the carrying value of the Hydro One Brampton investment over its tax basis. The balance of $17 million, which is the tax effect of the difference between tax basis and the fair value of note receivable and the tax effect of the difference between the carrying value and the fair value of the Hydro One Brampton investment, is recorded in equity.

3. PRO FORMA SHARES OUTSTANDING

The average number of shares used in the computation of pro forma basic and diluted earnings per share has been determined as follows:

Opening weighted average shares outstanding of Hydro One Inc.	100,000
Common shares issued in connection with preferred share redemption (note 2H)	2,706
Common shares issued in connection with $2,600 million subscription by Hydro One Limited (note 2B)	42,797
Pro forma weighted average shares of Hydro One Inc.	145,503

APPENDIX A
BOARD MANDATE

The board of directors (the "**Board**") of Hydro One Limited (including its subsidiaries, the "**Company**") is elected by the shareholders and is responsible for overseeing the business and affairs of the Company. The Board seeks to discharge such responsibility by reviewing, discussing and approving the Company's strategic planning and organizational structure and supervising management, all with a view to preserving and enhancing the business of the Company and its underlying value.

Responsibilities

While the Board maintains oversight of the Company's operations, it delegates to the Chief Executive Officer and senior management of the Company the responsibility for day-to-day management of the Company. The Board discharges its oversight responsibilities both directly and through its committees, the Audit Committee, the Nominating, Corporate Governance, Public Policy & Regulatory Committee, the Human Resources Committee and the Health, Safety, Environment, and First Nations & Métis Committee. In addition to these regular committees, the Board may appoint *ad hoc* committees periodically to address specific matters.

The Board's primary roles are overseeing both corporate performance and the quality, depth and continuity of management required to meet the Company's strategic objectives. Other principal duties include:

Culture of Integrity

1. supporting a corporate culture of integrity and responsible stewardship.
2. satisfying itself, to the extent feasible, as to the integrity of the Chief Executive Officer and other executive officers, and that such individuals promote a culture of integrity throughout the Company.

Capital and Financial Structure

3. approving the capital and financial structure of the Company.
4. approving the declaration and payment of dividends.

Strategic Planning

5. overseeing and reviewing, questioning and approving the mission and vision of the Company as well as its strategy, objectives and goals, taking into account the opportunities available to the Company, the potential risks it faces, and the Company's risk appetite.
6. reviewing, providing input on, and approving the budget and business, financial and strategic plans proposed by management to enable the Company to reach its objectives and goals.
7. adopting processes for monitoring the Company's performance and progress toward its strategic and operational goals.

Risk Management

8. overseeing the Company's enterprise risk management system for effectively identifying, monitoring and managing the risks it faces with a view to achieving a proper balance between the risks incurred and potential returns and the long term sustainability of the Company.
9. approving policies and procedures designed to ensure that the Company operates responsibly and in compliance with applicable laws and regulations.

Appointment and Oversight of Management

10. approving the appointment of, and if necessary removing and replacing, the Chief Executive Officer, approving his or her compensation and approving succession plans for the Chief Executive Officer.
11. overseeing the process for appointment, removal and replacement of all other executive officers, their compensation and the succession planning processes of the Company.

12. delegating to senior management the authority for expenditures and transactions, subject to specified limits beyond which Board approval would be required.

Corporate Governance

13. approving the Company's approach to corporate governance, having regard to the Governance Agreement between the Company and the Province of Ontario (as amended, revised or replaced from time to time, the "Governance Agreement"), including the Board's mandate, committee mandates, committee appointments, corporate governance guidelines, position descriptions for the Board Chair and of the committee chairs and director compensation and protection.

14. overseeing structures and procedures to enable the Board to exercise independent judgement.

15. overseeing succession-planning for the Board, orientation and educational opportunities for directors and the regular assessment of the effectiveness of the Board as a whole, each committee, the Board Chair, each Committee Chair, and each individual director.

16. delegating to Board committees oversight of specific matters, but except for the authority of the Nominating, Corporate Governance, Public Policy & Regulatory Committee over the management and oversight of the director nomination process pursuant to the Governance Agreement, otherwise retaining ultimate responsibility for those delegated matters

17. enforcing Board policy respecting confidentiality of the Company's proprietary information and Board deliberations.

Communications and Reporting

18. monitoring and supporting investor relations activities and reporting annually to shareholders on the Board's exercise of its oversight responsibilities for the preceding year.

19. reviewing communications plans for shareholders, employees, customers, financial analysts, governments and regulatory authorities, the media and other stakeholders, as well as processes to ensure the timely, accurate and complete disclosure of developments that have a significant and material impact on the Company.

20. overseeing the accurate disclosure and reporting of the financial performance of the Company to shareholders, other security holders and regulators on a timely and regular basis;

21. assessing the Company's stakeholder engagement policies and practices including systems to accommodate feedback from shareholders and other stakeholders.

APPENDIX B
AUDIT COMMITTEE MANDATE

Purpose

The Audit Committee (the "**Committee**") is a committee appointed by the board of directors (the "**Board**") of Hydro One Limited (including its subsidiaries, the "**Company**"). The Committee is established to fulfill applicable public company obligations and to assist the Board in fulfilling its oversight responsibilities with respect to financial reporting including responsibility to oversee:

(a) the independence, qualification and appointment of external auditors;

(b) the integrity of the Company's financial statements and financial reporting process, including the audit process and the Company's internal control over financial reporting, disclosure controls and procedures and compliance with other related legal and regulatory requirements;

(c) the performance of the Company's financial finance function, internal auditors and external auditors; and

(d) the auditing, accounting and financial reporting process.

The function of the Committee is oversight. It is not the duty or responsibility of the Committee or its members: (a) to plan or conduct audits; (b) to determine that the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting principles; or (c) to conduct other types of auditing or accounting reviews or similar procedures or investigations. The Committee, its Chair and its members with accounting or finance expertise are members of the Board, appointed to the Committee to provide broad oversight of the financial, risk and control related activities of the Company, and are specifically not accountable or responsible for the day to day operation or performance of such activities.

Procedures

1. **Number of Members** – The members of the Committee shall be appointed by the Board. The Committee will be composed of not less than three (3) Board members.

2. **Independence** – The Committee shall be constituted at all times of directors who are "independent" (a) within the meaning of all Canadian securities laws and stock exchange requirements, each as in effect and applicable to Hydro One Inc. from time to time; and (b) of the Province of Ontario within the meaning of the Governance Agreement between the Company and the Province of Ontario (as amended, revised or replaced from time to time, the "**Governance Agreement**").

3. **Financial Literacy** – Each member shall be "financially literate" within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including NI 52-110. At least one member will otherwise qualify as an "audit committee financial expert" as defined by applicable rules of the Securities and Exchange Commission.

4. **Cross-Appointment** – No member may serve on the audit committee of more than two other public companies, unless the Board determined that this simultaneous service would not impair the ability of the member to serve effectively on the Committee.

5. **Appointment and Replacement of Committee Members** – Any member of the Committee may be removed or replaced at any time by the Board and shall automatically cease to be a member of the Committee upon ceasing to be a director. The Board shall fill any vacancy if the membership of the Committee is less than three directors. Whenever there is a vacancy on the Committee, the remaining members may exercise all its power as long as a quorum remains in office. Subject to the foregoing, the members of the Committee shall be appointed by the Board annually and each member of the Committee shall remain on the Committee until his or her successor shall be duly appointed and qualified or his or her earlier resignation or removal.

6. **Committee Chair** – Unless a Committee Chair is designated by the full Board, the members of the Committee may designate a Chair by majority vote of the full Committee. The Committee Chair shall be responsible for leadership of the Committee and reporting to the Board. If the Committee Chair is not present at any meeting of the Committee, one of the other members of the Committee who is present shall be chosen by the Committee to preside at the meeting. The Committee Chair shall also appoint a secretary who need not be a director.

7. **Conflicts of Interest** – If a Committee member faces a potential or actual conflict of interest relating to a matter before the Committee, other than matters relating to the compensation of directors, that member shall be responsible for alerting the Committee Chair. If the Committee Chair faces a potential or actual conflict of interest, the Committee Chair shall advise the Board Chair. If the Committee Chair, or the Board Chair, as the case may be, concurs that a potential or actual conflict of interest exists, the member faced with such conflict shall disclose to the Committee the member's interest and shall not be present for or participate in any discussion or other consideration of the matter and shall not vote on the matter.

8. **Meetings** – The Committee shall meet regularly and as often as it deems necessary to perform the duties and discharge its responsibilities as described herein in a timely manner, but not less than four (4) times a year. The Committee shall maintain written minutes of its meetings, which will be filed with the meeting minutes of the Board.

9. **Separate Private Meetings** – The Committee shall meet regularly, but no less than quarterly, with the Chief Financial Officer, the head of the internal audit function (if other than the Chief Financial Officer) and the external auditors in separate private sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately and such persons shall have access to the Committee to bring forward matters requiring its attention. The Committee shall also meet at each meeting of the Committee without management or non-independent directors present, unless otherwise determined by the Committee Chair.

10. **Professional Assistance** – The Committee may require the external auditors to perform such supplemental reviews or audits as the Committee may deem desirable and may retain such special legal, accounting, financial or other consultants as the Committee may determine to be necessary to carry out the Committee's duties, in each case at the Company's expense and inform the Chair of the Nominating and Corporate Governance Committee of any such retainer. The Company's external auditors will have direct access to the Committee at their own initiative.

11. **Reliance** – Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on: (a) the integrity of those persons or organizations within and outside the Company from which it receives information; (b) the accuracy of the financial and other information provided to the Committee by such persons or organizations; and (c) representations made by management and the external auditors as to any information technology, internal audit and other permissible non-audit services provided by the external auditors to the Company and its subsidiaries.

12. **Reporting to the Board** – The Committee will report through the Committee Chair to the Board following meetings of the Committee on matters considered by the Committee, its activities and compliance with this Mandate.

Responsibilities

The principal responsibilities of the Committee are:

Selection and Oversight of the External Auditors

1. approve the terms of engagement and, if the shareholders authorize the Board to do so, the compensation to be paid by the Company to the external auditors with respect to the conduct of the annual audit. The external auditors are ultimately accountable to the Committee and the Board as the representatives of the shareholders of the Company and shall report directly to the Committee and the Committee shall so instruct the external auditors.

2. evaluate the quality of service, independence, objectivity, professional skepticism and performance of the external auditors and make recommendations to the Board on the reappointment or appointment of the external auditors of the Company to be proposed for shareholder approval and shall have authority to terminate the external auditors. If a change in external auditors is proposed by the Committee or management of the Company, the Committee shall review the reasons for the change and any other significant issues related to the change, including the response of the incumbent external auditors, and enquire on the qualifications of the proposed external auditors before making its recommendation to the Board.

3. review and approve policies and procedures for the pre-approval of services to be rendered by the external auditors. All permissible non-audit services to be provided to the Company or any of its affiliates by the external

auditors or any of their affiliates that are not covered by pre-approval policies and procedures approved by the Committee shall be subject to pre-approval by the Committee. The Committee shall have the sole discretion regarding the prohibition of the external auditor providing certain non-audit services to the Company and its affiliates. The Committee shall also review and approve disclosures with respect to permissible non-audit services.

4. review the independence and professional skepticism of the external auditors and make recommendations to the Board on appropriate actions to be taken which the Committee deems necessary to protect and enhance the independence of the external auditors. In connection with such review, the Committee shall:

   (a) actively engage in a dialogue with the external auditors about all relationships or services that may impact the objectivity and independence of the external auditors, including whether there are any disputes, restrictions or limitations placed on their work;

   (b) obtain from external auditors at least annually, a formal written statement delineating all relationships between the Company and the external auditors and their affiliates;

   (c) ensure the rotation of the lead (and concurring) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by applicable law or professional practice; and

   (d) consider the auditor independence standards promulgated by applicable auditing regulatory and professional bodies.

5. review and approve policies for the hiring by the Company of employees or former employees of the external auditors.

6. require the external auditors to provide to the Committee, and review and discuss with the external auditors, all notices and reports which the external auditors are required to provide to the Committee or the Board under rules, policies or practices of professional or regulatory bodies applicable to the external auditors, and any other reports which the Committee may require. Such reports shall include:

   (a) a description of the external auditors' internal quality-control procedures, any material issues respecting the external auditors raised by the most recent internal quality-control review, peer review or review body with auditing oversight responsibility over the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues; and

   (b) a report describing: (i) the proposed audit plan and approach, (ii) all critical accounting policies and practices to be used by the Company; (iii) all alternative treatments of financial information within generally accepted accounting principles related to material items that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and (iv) other material written communication between the external auditors and management, such as any management letter or schedule of unadjusted differences.

7. meet periodically with the external auditors to discuss their audit plan for the year, progress of their activities, any significant findings stemming from the external audit, any changes required in the planned scope of their audit plan, whether there are any disputes or any restrictions or limitations on the external auditors.

8. review the experience and qualifications of the audit team and review the performance of the external auditors, including assessing their effectiveness and quality of service, annually and, every five (5) years, perform a comprehensive review of the performance of the external auditors over multiple years to provide further insight on the audit firm, its independence and application of professional standards.

Appointment and Oversight of Internal Auditors

9. review and approve the appointment, terms of engagement, compensation, replacement or dismissal of the internal auditors. When the internal audit function is performed by employees of the Company, the Committee may delegate responsibility for approving the employment, terms of employment, compensation and termination of employees engaged in such function other than the head of the Company's internal audit function.

10. meet periodically with the internal auditors to discuss their audit plan for the year, progress of their activities, any significant findings stemming from internal audits, any changes required in the planned scope of their audit plan and whether there are any disputes, restrictions or limitations on internal audit.

11. review summaries of the significant reports to management prepared by the internal auditors, or the actual reports if requested by the Committee, and management's responses to such reports.

12. communicate with, as it deems necessary, the internal auditors with respect to their reports and recommendations, the extent to which prior recommendations have been implemented and any other matters that the internal auditor brings to the attention of the Committee. The head of the internal audit function shall have unrestricted access to the Committee.

13. evaluate, annually or more frequently as it deems necessary, the internal audit function, including its activities, organizational structure, independence and the qualifications, effectiveness and adequacy of the function.

Oversight and Review of Accounting Principles and Practices

14. review and discuss with management, the external auditors and the internal auditors (together and separately as it deems necessary), among other items and matters:

    (a) the quality, appropriateness and acceptability of the Company's accounting principles, practices and policies used in its financial reporting, its consistency from period to period, changes in the Company's accounting principles or practices and the application of particular accounting principles and disclosure practices by management to new transactions or events;

    (b) all significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including the effects of alternative methods within generally accepted accounting principles on the financial statements and any "second opinions" sought by management from an external auditor with respect to the accounting treatment of a particular item;

    (c) any material change to the Company's auditing and accounting principles and practices as recommended by management, the external auditors or the internal auditors or which may result from proposed changes to applicable generally accepted accounting principles;

    (d) the extent to which any changes or improvements in accounting or financial practices, as approved by the Committee, have been implemented;

    (e) any reserves, accruals, provisions or estimates that may have a material effect upon the financial statements of the Company;

    (f) the use of any "pro forma" or "adjusted" information which is not in accordance with generally accepted accounting principles;

    (g) the effect of regulatory and accounting initiatives on the Company's financial statements and other financial disclosures; and

    (h) legal matters, claims and contingencies that could have a significant impact on the Company's financial statements.

15. review and resolve disagreements between management and the external auditors regarding financial reporting or the application of any accounting principles or practices.

Oversight and Monitoring of Internal Controls

16. exercise oversight of, review and discuss with management, the external auditors and the internal auditors (together and separately, as it deems necessary:

    (a) the adequacy and effectiveness of the Company's internal control over financial reporting and disclosure controls and procedures designed to ensure compliance with applicable laws and regulations;

    (b) any significant deficiencies or material weaknesses in internal control over financial reporting or disclosure controls and procedures, and the status of any plans for their remediation;

    (c) the adequacy of the Company's internal controls and any related significant findings and recommendations of the external auditors and internal auditors together with management's responses thereto; and

    (d) management's compliance with the Company's processes, procedures and internal controls.

Oversight and Monitoring of the Company's Financial Reporting and Disclosures

17. review with the external auditors and management and recommend to the Board for approval the audited annual financial statements and unaudited interim financial statements, and the notes and Managements' Discussion and Analysis accompanying all such financial statements, the Company's annual report and any other disclosure documents or regulatory filings containing or accompanying financial information of the Company, prior to the release of any summary of the financial results or the filing of such reports with applicable regulators.

18. discuss earnings press releases prior to their distribution, as well as financial information and earnings guidance prior to public disclosure, it being understood that such discussions may, in the discretion of the Committee, be done generally (i.e., by discussing the types of information to be disclosed and the type of presentation to be made) and that the Committee need not discuss in advance each earnings release or each instance in which the Company gives earning guidance.

19. review with management the Company's disclosure controls and procedures and material changes to the design of the Company's disclosure controls and procedures.

20. receive and review the financial statements and other financial information of material subsidiaries of the Company and any auditor recommendations concerning such subsidiaries.

21. meet with management to review the adequacy of the process and systems in place for ensuring the reliability of public disclosure documents that contain audited and unaudited financial information.

Oversight of Finance Matters

22. periodically review matters pertaining to the Company's material policies and practices respecting cash management and material financing strategies or policies or proposed financing arrangements and objectives of the Company.

23. periodically review the Company's major financial risk exposures (including foreign exchange and interest rate) and management's initiatives to control such exposures, including the use of financial derivatives and hedging activities.

24. review and discuss with management all material off-balance sheet transactions, arrangements, obligations (including contingent obligations), leases and other relationships of the Company with unconsolidated entities or other persons, that may have a material current or future effect on financial condition, changes in financial condition, results of operations, liquidity, capital resources, capital reserves, or significant components of revenues or expenses.

25. review and discuss with management any equity investments, acquisitions and divestitures that may have a material current or future effect on financial condition, changes in financial condition, results of operations, liquidity, capital resources, capital reserves, or significant components of revenues or expenses.

26. review and discuss with management the Company's effective tax rate, adequacy of tax reserves, tax payments and reporting of any pending tax audits or assessments, and material tax policies and tax planning initiatives.

27. review the organizational structure of the finance function and satisfy itself as to the qualifications, effectiveness and adequacy of the function.

28. review the work plan and progress on implementation of major information technology system changes and satisfy itself as to the adequacy of the information system infrastructure.

Regulatory Matters

29. review the financial impact to the Company of electrical regulatory initiatives.

30. review the financial implications of Company initiatives which may have a material impact on transmission and distribution rate filing applications.

Code of Business Conduct and Whistleblower Policy

31. review and recommend to the Board for approval any changes to the Code of Business Conduct for employees, officers and directors of the Company.

32. review and approve changes to the whistleblower policy or other procedures for: (a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

33. oversee management's monitoring of, compliance with the Company's Code of Business Conduct and the Whistleblower Policy.

Enterprise Risk Management

34. review the Enterprise Risk Management framework for the Company and assess the adequacy and completeness of the process for identifying and assessing the key risks facing the Company.

35. meet with the head of the Enterprise Risk Management function at least semiannually.

36. ensure that primary oversight responsibility for each of the key risks identified in the Enterprise Risk Management framework is assigned to the Board or one of its Committees.

Additional Responsibilities

37. review the Company's privacy and data security risk exposures and measures taken to protect the security and integrity of its management information systems and Company and customer data.

38. review and approve in advance any proposed related-party transactions and required disclosures of such in accordance with applicable securities laws and regulations and consistent with the Company's related party transaction policy, and report to the Board on any approved transactions.

39. review on an annual basis reports on the expense accounts of the Chief Executive Officer and his or her direct reports.

40. undertake on behalf of the Board such other initiatives as may be necessary or desirable to assist the Board in fulfilling its oversight responsibilities with respect to financial reporting and perform such other functions as required by law, stock exchange rules or the Company's constating documents.

41. review annually the adequacy of this Mandate and ensure that it is disclosed in compliance with applicable securities laws and stock exchange rules and posted on the Company's website.

CERTIFICATE OF HYDRO ONE LIMITED AND HYDRO ONE INC.

Dated: October 29, 2015

This prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under the securities legislation of each of the provinces and territories of Canada.

HYDRO ONE LIMITED

(Signed) MAYO SCHMIDT President and Chief Executive Officer	(Signed) MICHAEL VELS Chief Financial Officer

On Behalf of the Board of Directors

(Signed) DAVID DENISON Director	(Signed) PHILIP ORSINO Director

HYDRO ONE INC.
(as promoter)

(Signed) MAYO SCHMIDT President and Chief Executive Officer	(Signed) MICHAEL VELS Chief Financial Officer

On Behalf of the Board of Directors

(Signed) DAVID DENISON Director	(Signed) PHILIP ORSINO Director

CERTIFICATE OF THE UNDERWRITERS

Dated: October 29, 2015

To the best of our knowledge, information and belief, this prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under the securities legislation of each of the provinces and territories of Canada.

RBC Dominion Securities Inc.	Scotia Capital Inc.
By: (Signed) David Dal Bello	By: (Signed) Thomas Kurfurst

BMO Nesbitt Burns Inc.	CIBC World Markets Inc.	TD Securities Inc.
By: (Signed) Greg Petit	By: (Signed) David Williams	By: (Signed) Harold R. Holloway

National Bank Financial Inc.

By: (Signed) Iain Watson

Barclays Capital Canada Inc.	Credit Suisse Securities (Canada), Inc.	Goldman Sachs Canada Inc.
By: (Signed) Bruce M. Rothney	By: (Signed) Ryan Lapointe	By: (Signed) Luke Gordon

Canaccord Genuity Corp.	Desjardins Securities Inc.	GMP Securities L.P.	Raymond James Ltd.
By: (Signed) Steven Winokur	By: (Signed) François Carrier	By: (Signed) Alfred Avanessy	By: (Signed) J. Graham Fell

Dundee Securities Ltd.	Industrial Alliance Securities Inc.	Manulife Securities Incorporated
By: (Signed) David Anderson	By: (Signed) Richard Legault	By: (Signed) Stephen Arvanitidis

CERTIFICATE OF THE PROVINCE

Dated: October 29, 2015

This prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under the securities legislation of each of the provinces and territories of Canada.

HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO
as represented by the Minister of Energy
(as selling securityholder and promoter)

(Signed) BOB CHIARELLI

TRANSMISSION BUSINESS

- **Scale:** We are one of North America's largest electricity transmitters, owning and operating 96% of Ontario's network.
- **Stability:** Transmission produces reliable cash flow with low volatility under OEB cost of service regulation.
- **Growth:** We are building our rate base with planned low-risk capital expenditures of $800 – $900 million per year through 2019.

- 48 local distribution company customers
- 90 large industrial customers

5 year average allowed ROE of 9.15%

DISTRIBUTION BUSINESS

- **Scale:** We are the largest electricity distributor in Ontario, with 1.3 million residential and business customers.
- **Stability:** Distribution is a stable, rate-regulated business operating under the OEB's performance-based model.
- **Growth:** We are building our rate base with planned low-risk capital expenditures of $600 – $700 million per year through 2019.

5 year average allowed ROE of 9.70%

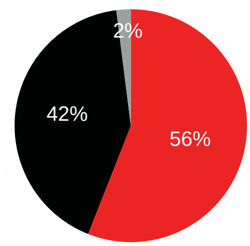
hydroOne AT A GLANCE

LARGEST **ELECTRICITY TRANSMISSION** AND **DISTRIBUTION** BUSINESS IN ONTARIO

$23.2 BILLION OF ASSETS

STABLE **AND REGULATED CORE** BUSINESSES

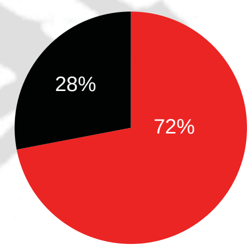
Total Assets at June 30, 2015



$23.2 billion

Transmission
Distribution
Other

2014 Net Income



$747 million

2014 FINANCIAL PERFORMANCE

$6.5 BILLION IN REVENUE

$747 MILLION IN NET INCOME

$1.29 BILLION IN FUNDS FROM OPERATIONS[1]

29,344 CIRCUIT-KILOMETRES OF **TRANSMISSION LINES**

1.27 MILLION **DISTRIBUTION** CUSTOMERS

[1] FFO is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) noncontrolling interest distributions. See "Non-GAAP Measures".

SHORT FORM BASE SHELF PROSPECTUS

New Issue and/or Secondary Offering March 30, 2016

hydro One

HYDRO ONE LIMITED

$8,000,000,000

Common Shares
Preferred Shares
Debt Securities
Subscription Receipts
Warrants
Units

Hydro One Limited may from time to time issue, offer and sell, as applicable, the following securities of Hydro One Limited under this short form base shelf prospectus (the "**Prospectus**"): (i) common shares ("**Common Shares**"); (ii) preferred shares, issuable in one or more series (collectively, "**Preferred Shares**"); (iii) debentures, notes or other evidence of indebtedness of any kind, nature or description (collectively, "**Debt Securities**"); (iv) subscription receipts ("**Subscription Receipts**"); (v) warrants ("**Warrants**") and (vi) units ("**Units**"). The Common Shares, Preferred Shares, Debt Securities, Subscription Receipts, Warrants and Units (collectively, the "**Securities**") offered hereby may be offered or sold separately or together, in separate series, in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in one or more prospectus supplements to the Prospectus (each, a "**Prospectus Supplement**" and together, the "**Prospectus Supplements**"). Her Majesty the Queen in Right of Ontario and/or her designee (the "**Province**" or the "**Selling Shareholder**") may also offer and sell Common Shares and Preferred Shares under this Prospectus. See "Selling Shareholder".

The aggregate initial offering price of Securities (or the Canadian dollar equivalent thereof if the Securities are denominated in any other currency or currency unit) that may be sold pursuant to this Prospectus during the 25-month period that this Prospectus, including any amendments hereto, remains effective is limited to $8,000,000,000.

All information permitted under applicable laws to be omitted from this Prospectus will be contained in one or more Prospectus Supplements that will be delivered to purchasers together with this Prospectus. Each Prospectus Supplement will be incorporated by reference into this Prospectus for the purposes of securities legislation as of the date of such Prospectus Supplement and only for the purposes of the distribution of the Securities to which such Prospectus Supplement pertains.

The outstanding Common Shares are listed and admitted for trading on the Toronto Stock Exchange ("**TSX**") under the symbol "H". On March 29, 2016, the last trading day prior to the date of this Prospectus, the closing price of the Common Shares on the TSX was $23.69 per Common Share. Unless otherwise specified in the applicable Prospectus Supplement, Securities other than Common Shares will not be listed on any securities exchange. **There is no market through which the Securities, other than the Common Shares, may be sold, and purchasers may not be able to resell such Securities purchased under this Prospectus and any applicable Prospectus Supplement. This may affect the pricing of such Securities in the secondary market, the transparency and availability of trading prices, the liquidity of the Securities and the extent of issuer regulation. See "Plan of Distribution".** Unless otherwise indicated in the Prospectus Supplement relating to an offering of Securities, the particular offering of Securities will be subject to approval of certain legal matters on behalf of Hydro One Limited by Osler, Hoskin & Harcourt LLP.

Investing in the Securities involves significant risks. Under securities laws in certain jurisdictions, the statutory remedies of rescission or damages where this Prospectus contains a misrepresentation are not available against the Province, as selling shareholder. The commencement of actions and enforcement of remedies against the Province may also be subject to limitations. The Province will not provide any guarantee in respect of the Securities. Prospective investors should carefully read and consider the risk factors described or referenced under the heading "Risk Factors" in this Prospectus, contained in any of the documents incorporated by reference herein, and in any applicable Prospectus Supplement, before purchasing Securities.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process. See "Agent for Service of Process in Canada."

The specific terms of the Securities in respect of which this Prospectus is being delivered will be set forth in an accompanying Prospectus Supplement and may include, where applicable: (i) in the case of Common Shares, the person(s) offering the shares (Hydro One Limited and/or the Selling Shareholder), the number of Common Shares offered and the offering price; (ii) in the case of Preferred Shares, the person(s) offering the shares (Hydro One Limited and/or the Selling Shareholder), the series, the number of Preferred Shares offered, the offering price, the dividend rate, the dividend payment dates, any terms for redemption at the option of Hydro One Limited or at the option of the holder, any exchange or conversion terms and any other specific terms that are material to the series of Preferred Shares; (iii) in the case of Debt Securities, the designation of the particular series, the aggregate principal amount of Debt Securities being offered, the offering price and any other material terms and conditions of the Debt Securities; (iv) in the case of Subscription Receipts, the number of Subscription Receipts being offered, the offering price, the conditions and procedures for exchange of the Subscription Receipts for other Securities of Hydro One Limited and any other material terms and conditions of the Subscription Receipts; (v) in the case of Warrants, the designation, number and terms of the other Securities purchasable upon exercise of the Warrants, any procedures that will result in the adjustment of these numbers, the exercise price, dates and periods of exercise and any other material terms and conditions of the Warrants; and (vi) in the case of Units, the designation of the Units and of the Securities comprising the Units and any other material terms and conditions of the Units.

Hydro One Limited reserves the right to include in a Prospectus Supplement specific variable terms pertaining to the Securities that are not within the descriptions set forth in this Prospectus.

Prospective investors should be aware that the acquisition of the Securities described herein may have tax consequences. This Prospectus does not, and any applicable Prospectus Supplement may not fully, describe these tax consequences. Prospective investors should read the tax discussion in any applicable Prospectus Supplement, but note that such discussion may be only a general summary that does not cover all tax matters

that may be of importance to a prospective investor. Each prospective investor is urged to consult its own tax advisors about the tax consequences relating to the purchase, ownership and disposition of the Securities in light of the investor's own circumstances.

No underwriter or agent has been involved in the preparation of this Prospectus or has performed any review of the contents of this Prospectus.

This Prospectus constitutes a public offering of Securities in only those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell the Securities. Hydro One Limited and the Selling Shareholder may offer and sell Securities to, or through, underwriters and also may offer and sell certain Securities directly to other purchasers or through agents. See "Plan of Distribution".

A Prospectus Supplement relating to a particular offering of Securities will identify the person(s) offering the Securities, as applicable, each underwriter or agent, as the case may be, engaged by Hydro One Limited and/or the Selling Shareholder in connection with the offering and sale of the Securities, and will set forth the terms of the offering of the Securities, including the public offering price of such Securities (or the manner of determination thereof if offered on a non-fixed price basis), the proceeds to, and the portion of expenses borne by, Hydro One Limited and/or the Selling Shareholder, as applicable, from such sale, any underwriting discounts or commissions and any discounts or concessions allowed, re-allowed or paid by any underwriter to other dealers and other material terms of the plan of distribution.

In connection with any offering of the Securities (unless otherwise specified in a Prospectus Supplement), the underwriters or agents may over-allot or effect transactions which stabilize, maintain or otherwise affect the market price of the Securities offered at levels other than those which might otherwise prevail on the open market. These transactions may be commenced, interrupted or discontinued at any time. See "Hydro One Limited has a long term credit rating of A (stable) from Standard & Poor's Rating Services ("**S&P**"), although it has not obtained a credit rating in respect of any of the Securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of the Securities and does not comment on the market price or suitability of any of the Securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One Limited has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One Limited and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of the Securities.

Plan of Distribution".

The head and registered office of Hydro One Limited is located at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

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ABOUT THIS PROSPECTUS

In this Prospectus and in any Prospectus Supplement, unless otherwise noted or the context otherwise requires, references to "**Hydro One**" or the "**Company**" refer to Hydro One Limited and its subsidiaries taken together as a whole. References to "**Hydro One Inc.**" refer only to Hydro One Inc. and references to "**Hydro One Limited**" refer only to Hydro One Limited. In addition, "**Ontario**" or the "**province**" in lower case type refers to the Province of Ontario as a geographical area.

All references in this Prospectus to "**dollars**" and "**$**" are to Canadian dollars, unless otherwise expressly stated. Unless otherwise expressly stated therein, the financial information of Hydro One Limited contained in the documents incorporated by reference herein are presented in Canadian dollars. Hydro One Limited prepares and presents its financial statements in accordance with U.S. GAAP. Unless otherwise indicated, all financial information included and incorporated by reference in this Prospectus or included in any Prospectus Supplement is determined using U.S. GAAP. "**U.S. GAAP**" means generally accepted accounting principles in the United States.

For prospective purchasers outside Canada, Hydro One Limited has not done anything that would permit this offering or possession or distribution of this Prospectus or any Prospectus Supplement in any jurisdiction where action for that purpose is required, other than in Canada. Prospective purchasers are required to inform themselves about, and to observe any restrictions relating to, this offering and the possession or distribution of this Prospectus or any Prospectus Supplement.

This Prospectus includes or the documents incorporated by reference herein include a summary of certain material agreements of Hydro One Limited. The summary descriptions are not complete and are qualified by reference to the terms of the material agreements, which have been filed with the Canadian securities regulatory authorities and are available on SEDAR under Hydro One Limited's profile at www.sedar.com. Investors are encouraged to read the full text of such material agreements.

Hydro One Limited is responsible for the information contained in or incorporated by reference in this Prospectus or any applicable Prospectus Supplement. Hydro One Limited has not authorized anyone to provide you with different or additional information. Investors should only rely on the information contained in this Prospectus or any Prospectus Supplement and in the documents incorporated by reference herein and therein and investors are not entitled to rely on parts of such information to the exclusion of others. Hydro One Limited is not making an offer of these Securities in any jurisdiction where the offer is not permitted by law. You should not assume that the information contained in or incorporated by reference in this Prospectus or any applicable Prospectus Supplement is accurate as of any date other than the date of the applicable document.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Prospectus, including the documents incorporated by reference herein, contains "forward-looking information" within the meaning of applicable Canadian securities laws that is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs and assumptions made by management. Such information includes, but is not limited to, statements about the Company's business, the intentions of the Province with respect to future sales of Common Shares and statements concerning the content of future Prospectus Supplements. Additional forward-looking information is identified in the various documents incorporated by reference in this Prospectus. Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target" and variations of such words and similar expression are intended to identify such forward-looking information. The forward-looking information contained or incorporated by reference in this Prospectus, are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. In particular, this forward-looking information is based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; no unfavourable changes in environmental regulation; the continued use and availability of U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company including information obtained by the Company from third-party sources. Actual outcomes and results may differ materially from what is expressed, implied or forecasted in this forward-looking information. While the Company does not know what impact any of these differences may have, the Company's business, results of operations and financial conditions may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are discussed in more detail under "Risk Factors" in this Prospectus or in any Prospectus Supplement, under "Risk Factors" in Hydro One Limited's most recent annual information form and under "Risk Management and Risk Factors" in Hydro One Limited's most recent annual management's discussion and analysis of financial results. You should carefully consider these and other factors and not place undue reliance on forward-looking information.

Hydro One Limited does not undertake or assume any obligation to update or revise any forward-looking information for any reason, except as required by applicable securities laws.

DOCUMENTS INCORPORATED BY REFERENCE

The following documents, filed by Hydro One Limited with the securities commissions or similar authorities in each of the provinces and territories of Canada, and as amended from time to time, are specifically incorporated by reference into, and form an integral part of, this Prospectus:

(a) Hydro One Limited's annual information form dated March 22, 2016 for the year ended December 31, 2015;

(b) Hydro One Limited's audited consolidated annual financial statements for the years ended December 31, 2015 and December 31, 2014, together with the notes thereto and the independent auditors' reports thereon dated February 11, 2016 (the "**2015 Annual Financial Statements**");

(c) Hydro One Limited's management's discussion and analysis in respect of the 2015 Annual Financial Statements;

(d) Hydro One Limited's business acquisition report dated January 14, 2016 relating to the acquisition by Hydro One Limited on October 31, 2015 of all of the issued and outstanding shares of Hydro One Inc.; and

(e) the following sections of the supplemented PREP prospectus of Hydro One Limited dated October 29, 2015 (the "**HOL Prospectus**") in respect of Hydro One Limited's initial public offering by way of a secondary offering of Common Shares by the Province:

  (i) disclosure under "Meaning of Certain References" at page 1 of the HOL Prospectus;

  (ii) disclosure under the subheadings "Directors and Executive Officers – Biographical Information" (but only in respect of the biographies of the directors and not the executive officers) at pages 125 to 129 of the HOL Prospectus;

  (iii) disclosure under the subheadings "Independence of the Board of Directors", "Directors' Board Memberships in Other Reporting Issuers", "Board Mandate", "Position Descriptions", "Orientation and Continuing Education", "Ethical Business Conduct", "Nomination of Directors", "Majority Voting Policy", "Board Renewal", "Diversity" and "Committees of the Board" at pages 130 to 136 of the HOL Prospectus, but excluding the disclosure under the subheadings "Audit Committee" and "External Auditor Service Fees" at pages 134 to 135 of the HOL Prospectus;

  (iv) disclosure under "Executive Compensation" at pages 136 to 153 of the HOL Prospectus;

  (v) disclosure under "Directors' Compensation" at pages 153 to 154 of the HOL Prospectus;

  (vi) disclosure under "Share Grant Plans" at pages 154 to 155 of the HOL Prospectus;

(vii) disclosure under “Glossary” at pages 178 to 182 of the HOL Prospectus;

(viii) Appendix A – Board Mandate at pages A-1 to A-2 of the HOL Prospectus; and

(ix) any other disclosures in the HOL Prospectus specifically referred to in the disclosures made in items (i) through (viii) above, in each case to the extent relevant.

(collectively, the “**Included Sections**”).

The Included Sections have been incorporated by reference into, and form a part of, this Prospectus because they contain certain information regarding the board of directors and management of Hydro One Limited, including executive and director compensation, and a description of Hydro One Limited’s corporate governance practices. In respect of certain references in the Included Sections to actions that will be taken by Hydro One Limited in the future, some of these actions have been taken and some remain to be taken. Hydro One Limited has determined there is no material information in the HOL Prospectus relating to Hydro One Limited or the Securities that has not been incorporated by reference into this Prospectus. Upon a management information circular relating to the annual meeting of shareholders of Hydro One Limited to be held on May 31, 2016 being filed by Hydro One Limited with and, where required, accepted by, the applicable securities commissions or similar authorities in Canada during the term of this Prospectus, the Included Sections shall be deemed no longer to be incorporated by reference into this Prospectus for purposes of future offers and sales of Securities hereunder.

Any document of the type referred to above, any annual information form, annual or quarterly financial statements, annual or quarterly management’s discussion and analysis, management information circular, material change report (excluding confidential material change reports), business acquisition report or other disclosure document required to be incorporated by reference into a prospectus filed under National Instrument 44-101- *Short Form Prospectus Distributions* filed by Hydro One Limited with the securities commissions or similar authorities in Canada after the date of this Prospectus and prior to 25 months from the date hereof shall be deemed to be incorporated by reference into this Prospectus.

Upon a new annual information form and the related annual audited consolidated financial statements and accompanying management’s discussion and analysis being filed by Hydro One Limited with and, where required, accepted by, the applicable securities commissions or similar authorities in Canada during the term of this Prospectus, the previous annual information form, the previous annual audited consolidated financial statements and accompanying management’s discussion and analysis and all interim financial statements and accompanying management’s discussion and analysis, and all material change reports and business acquisition reports filed by Hydro One Limited prior to the commencement of the then current fiscal year, shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Securities hereunder. Upon an interim financial statement and accompanying management’s discussion and analysis being filed by Hydro One Limited with and, where required, accepted by, the applicable securities commissions or similar authorities in Canada during the currency of this Prospectus, all interim financial statements and accompanying management’s discussion and analysis filed prior to the new interim financial statements shall be deemed no longer to be incorporated into this Prospectus for purposes of future offers and sales of Securities hereunder. Upon a new management information circular relating to an annual meeting of shareholders of Hydro One Limited being filed by Hydro One Limited with and, where required, accepted by, the applicable securities commissions or similar authorities in Canada during the term of this Prospectus, the management information circular for the preceding annual meeting of shareholders of Hydro One Limited (if any) shall be deemed no longer to be incorporated by reference into this Prospectus for purposes of future offers and sales of Securities hereunder.

Certain marketing materials (as that term is defined in applicable securities legislation in Canada) may be used in connection with a distribution of Securities under this Prospectus and any applicable Prospectus Supplement. Any “template version” of any “marketing materials” (as those terms are defined in National Instrument 41-101 – *General Prospectus Requirements*) pertaining to a distribution of Securities, and filed by Hydro One Limited after the date of the applicable Prospectus Supplement for the offering and before termination of the distribution of such Securities, will be deemed to be incorporated by reference in such Prospectus Supplement for the purposes of the distribution of Securities to which the Prospectus Supplement pertains.

A Prospectus Supplement containing the specific terms of any offering of Securities will be delivered to purchasers of such Securities together with this Prospectus and will be deemed to be incorporated by reference in this Prospectus as of the date of the Prospectus Supplement solely for the purposes of the offering of Securities thereunder.

Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded, for the purposes of this Prospectus, to the extent that a statement contained herein, or in any other subsequently filed document that also is, or is deemed to be, incorporated by reference herein, modifies or supersedes that statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that was required to be stated or that was necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this Prospectus, except as so modified or superseded.

THE COMPANY

Hydro One Limited was incorporated on August 31, 2015 under the *Business Corporations Act* (Ontario) (the "**OBCA**"). On October 31, 2015, Hydro One Limited acquired all of the issued and outstanding shares of Hydro One Inc. from the Province in exchange for the issuance of Common Shares and Series 1 Preferred Shares to the Province.

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and an approximately 123,000 circuit km low-voltage distribution network.

Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

Hydro One's transmission business consists of owning, operating and maintaining its transmission system, which accounts for 96% of Ontario's transmission capacity based on the revenues approved by the Ontario Energy Board. This includes Hydro One's 66% interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. Hydro One's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. Hydro One's transmission business accounted for approximately 50% of the Company's total assets as at December 31, 2015, and approximately 50% of its total revenues, net of purchased power, in 2015. All of Hydro One's transmission business is carried out by its wholly-owned subsidiary Hydro One Inc., through its wholly-owned subsidiary Hydro One Networks Inc., except for the portion of its business held through B2M Limited Partnership, which Hydro One controls.

Hydro One's distribution business consists of owning, operating and maintaining its distribution system, which Hydro One, through Hydro One Inc., owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. Hydro One's distribution system is also the largest in Ontario, and principally serves rural communities. Hydro One's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the Ontario Energy Board. Hydro One's distribution business accounted for approximately 38% of its total assets as at December 31, 2015 and approximately 48% of its total revenues, net of purchased power, in 2015.

Hydro One's other business segment consists of Hydro One's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for Hydro One's transmission and distribution businesses and also offers communications and IT solutions to organizations with broadband network requirements. Hydro One's other business segment is not rate-regulated. The other business segment, which in addition to the telecommunications business also includes a deferred tax asset, accounted for approximately 12% of Hydro One's total assets as at December 31, 2015 and approximately 2% of its total revenues, net of purchased power, in 2015.

The address of the head and registered office of Hydro One is 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

RECENT DEVELOPMENTS

On February 24, 2016, Hydro One Inc. completed an offering of $1,350,000,000 aggregate principal amount of medium term notes for net proceeds to Hydro One Inc. of $1,343,740,000. The offering consisted of $500,000,000 aggregate principal amount of 1.84% medium term notes (Series 34) due 2021, $500,000,000 aggregate principal amount of 2.77% medium term notes (Series 35) due 2026 and $350,000,000 aggregate principal amount of 3.91% medium term notes (Series 36) due 2046. Hydro One Inc. intends to use the net proceeds from the sale of the notes to repay maturing debt and for general corporate purposes. To date, Hydro One Inc. has used a portion of the net proceeds as noted under "Consolidated Capitalization".

RISK FACTORS

Prospective investors in a particular offering of Securities should carefully consider the risks presented in this Prospectus, as well as the information and risk factors contained in the Prospectus Supplement relating to that offering and any and all other information incorporated by reference in this Prospectus. Discussions of certain risks affecting Hydro One Limited are generally provided and described in, among other documents, Hydro One Limited's annual and interim disclosure documents filed from time to time, which are incorporated by reference into this Prospectus and include Hydro One Limited's annual information form and annual management's discussion and analysis. In particular, see "Risk Factors" in Hydro One Limited's latest annual information form and "Risk Management and Risk Factors" in Hydro One Limited's interim or annual management's discussion and analysis, as the case may be. If any event arising from these or any other risks occurs, the Company's business, prospects, financial condition, results of operations or cash flows could be materially adversely affected.

To the extent the Selling Shareholder is offering and selling Common Shares or Preferred Shares pursuant to this Prospectus, the following additional risk factor will be relevant.

Potential Difficulties in Enforcing Civil Liabilities Against the Province

Under the securities legislation of Ontario and Newfoundland and Labrador, the statutory remedies of rescission or damages where the Prospectus or any amendment (including any Prospectus Supplement) contains a misrepresentation are not available against the Province. It is also possible, based on prior court decisions, that a claim against the Province based on these statutory remedies would have to be brought in the Ontario courts, rather than in the courts of the purchaser's province or territory of residence. If the claim was brought in the Ontario courts, and Ontario law was applied in respect of the claim, the statutory remedies would not be available against the Province. Alternatively, if a purchaser of common shares were to successfully assert a statutory misrepresentation claim against the Province in a jurisdiction other than Ontario, the resulting judgment may not be enforceable in Ontario for reasons which include that an Ontario court could conclude that it would be contrary to Ontario public policy to do so. Nonetheless, recourse may continue to be available against Hydro One Limited and any other parties that may be liable for any such misrepresentation.

To the extent any particular offering of Securities is made to investors not resident in Canada, the following additional risk factor will be relevant.

Potential Difficulties in Enforcing Civil Liabilities Outside Canada

Hydro One Limited is incorporated under the laws of Ontario, Canada and substantially all of the Company's assets are located in Canada. Substantially all of the directors and officers of Hydro One Limited, and some experts named in this prospectus reside or are located in Canada, and their assets are located in Canada. As a result, it may be difficult for non-Canadian or other investors to effect service of process outside of Canada against Hydro One Limited the directors and officers of Hydro One Limited or these experts or to sue Hydro One Limited or those others in the United States or other courts. If a lawsuit were successful, it may be difficult to collect any money awarded.

In addition, to the extent any offering pursuant to this Prospectus is also made in the United States, in relation to potential claims by United States investors, the *United States Foreign Sovereign Immunities Act of 1976* (the "**FSIA**") provides that, subject to existing international agreements to which the United States was a party at the time of the enactment of the FSIA, a foreign state or any agency or instrumentality of a foreign state is immune from U.S. federal and state court jurisdiction unless a specific exception to the immunity applies. One such exception applies to claims arising out of "commercial activity" by a foreign state or its agency or instrumentality. However, it is not certain that a court would consider any acts or omissions by Hydro One Limited, Hydro One Inc. or the Province in connection with an offering pursuant to this Prospectus or otherwise to be "commercial activities" under the FSIA. Absent an applicable exception from immunity under the FSIA, any attempt to assert a claim against Hydro One Limited, Hydro One Inc. or the Province alleging a violation of the U.S. securities laws resulting from an alleged material misstatement in or material omission from this Prospectus, or any other act or omission in connection with an offering pursuant to this Prospectus, may be barred. Further, absent an applicable exception from immunity under the FSIA, any attempt to assert a claim against Hydro One Limited, Hydro One Inc. or the Province or any of their respective agents or employees alleging any other complaint, including as a result of any future action by the Province as a shareholder of Hydro One Limited, may also be barred. In addition, even if a U.S. judgment could be obtained in such an action, the results of such judgment may not be enforceable in Ontario.

CONSOLIDATED CAPITALIZATION

There have been no material changes in Hydro One Limited's share and loan capital, on a consolidated basis, since the date of the 2015 Annual Financial Statements, other than as noted below.

On February 24, 2016, Hydro One Inc. incurred $1,350,000,000 aggregate principal amount in additional indebtedness as a result of the completion of the offering of medium term notes described under "Recent Developments". To date, Hydro One Inc. has used a portion of the net proceeds of that offering to repay the $450,000,000 aggregate principal amount of 4.64% medium term notes (Series 10) which matured on March 3, 2016. In addition, Hydro One Inc. has used a portion of the net proceeds of that offering, together with cash on hand, to repay approximately $537,000,000 in commercial paper since December 31, 2015.

USE OF PROCEEDS

Unless otherwise indicated in the applicable Prospectus Supplement, Hydro One Limited intends to use the net proceeds received by it from the sale of Securities for working capital requirements or for other general corporate purposes which may include the repayment or refinancing of debt, funding acquisitions, funding capital expenditures or for other working capital needs. More detailed information regarding the use of proceeds from the sale of Securities will be described in the applicable Prospectus Supplement. Hydro One Limited may, from time to time, issue Securities otherwise than through the offering of Securities pursuant to this Prospectus.

Hydro One Limited will not receive any proceeds from any sale of Common Shares or Preferred Shares by the Selling Shareholder.

EARNINGS COVERAGE RATIO

Earnings coverage ratios will be provided as required in the applicable Prospectus Supplement(s) with respect to any offering and sale of Preferred Shares or Debt Securities pursuant to this Prospectus.

CREDIT RATINGS

Hydro One Limited has a long term credit rating of A (stable) from Standard & Poor's Rating Services ("**S&P**"), although it has not obtained a credit rating in respect of any of the Securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of the Securities and does not comment on the market price or suitability of any of the Securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One Limited has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One Limited and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of the Securities.

PLAN OF DISTRIBUTION

The Securities offered hereby may be sold (i) to, or through, underwriters; (ii) directly to one or more purchasers; or (iii) through agents. The Securities may be sold at fixed prices or non-fixed prices, such as prices determined by reference to the prevailing price of the Securities in a specified market, at market prices prevailing at the time of sale or at prices to be negotiated with purchasers, which prices may vary as between purchasers and during the period of distribution of the Securities.

A Prospectus Supplement relating to a particular offering of Securities will identify the person(s) offering the Securities, as applicable, each underwriter or agent, as the case may be, engaged by Hydro One Limited and/or the Selling Shareholder in connection with the offering and sale of the Securities, and will set forth the terms of the offering of the Securities, including the public offering price of such Securities (or the manner of determination thereof if offered on a non-fixed price basis), the proceeds to, and the portion of expenses borne by, Hydro One Limited and/or the Selling Shareholder, as applicable, from such sale, any underwriting discounts or commissions and any discounts or concessions allowed, re-allowed or paid by any underwriter to other dealers and other material terms of the plan of distribution.

If underwriters purchase Securities as principal, the Securities will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions, including negotiated transactions, at a fixed public offering price or at varying prices determined at the time of sale. The obligations of the underwriters to purchase such Securities will be subject to certain conditions precedent, and the underwriters will be obligated to purchase all of the Securities offered pursuant to any Prospectus Supplement if any of such Securities are purchased. Any public offering price and any discounts or concessions allowed, re-allowed or paid to dealers may be changed from time to time.

The Securities may also be sold (i) directly by Hydro One Limited and/or, in the case of Common Shares and Preferred Shares, the Selling Shareholder at such prices and upon such terms as agreed to by Hydro One Limited and/or the Selling Shareholder, as applicable, and one or more purchasers; or (ii) through agents designated by Hydro One Limited and/or the Selling Shareholder from time to time. Any agent involved in the offering and sale of the Securities in respect of which this Prospectus is delivered will be named, and any commissions payable by Hydro One Limited and/or the Selling Shareholder, as applicable, to such agent will be set forth, in the applicable Prospectus Supplement. Unless otherwise indicated in a Prospectus Supplement, any agent is acting on a best efforts basis for the period of its appointment.

Underwriters, dealers and agents who participate in the distribution of the Securities may be entitled under agreements to be entered into with Hydro One Limited and/or the Selling Shareholder to indemnification by Hydro One Limited and/or the Selling Shareholder, as applicable, against certain liabilities, including liabilities under securities legislation, or to contribution with respect to payments which such underwriters, dealers or agents may be required to make in respect thereof. Those underwriters, dealers and agents may be customers of, engage in transactions with or perform services for us or our subsidiaries in the ordinary course of business.

The Securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States. Accordingly, the Securities may not be offered, sold or delivered, directly or indirectly, within the United States (as defined in Regulation S ("**Regulation S**") under the U.S. Securities Act) (the "**United States**") or to, or for the account or benefit of, any U.S. persons (as defined in Regulation S) except to persons who are "qualified institutional buyers" in reliance on Rule 144A under the U.S. Securities Act ("**Rule 144A**") or in accordance with another exemption from registration, and each underwriter or agent will agree that it will not offer, sell or deliver the Securities within the United States or to any U.S. persons, except in accordance with Rule 144A or another exemption from registration under the U.S. Securities Act. In addition, with respect to an offering of Securities sold outside the United States in compliance with Regulation S, until 40 days after the commencement of such offering of Securities, an offer or sale of such Securities within the United States or to any U.S. persons by a dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act unless the dealer makes the offer or sale in accordance with Rule 144A or another exemption from the registration requirements of the U.S. Securities Act.

The Securities may also be sold internationally as permitted pursuant to private placement exemptions under local securities laws.

Each issue by Hydro One Limited of Preferred Shares, Debt Securities, Subscription Receipts, Warrants and Units will be a new issue of securities with no established trading market. In addition, there is currently no trading market for the Series 1 Preferred Shares and Series 2 Preferred Shares. Unless otherwise specified in a Prospectus Supplement relating to an offering of Preferred Shares, Debt Securities, Subscription Receipts, Warrants and Units (whether by Hydro One Limited or in the case of Preferred Shares, the Selling Shareholder), such Securities will not be listed on any securities or stock exchange. Any underwriters, dealers or agents to or through whom such Securities are sold may make a market in such Securities, but they will not be obligated to do so and may discontinue any market making at any time without notice. No assurance can be given that a trading market in any such Securities will develop or as to the liquidity of any trading market for such Securities.

In connection with any offering of the Securities (unless otherwise specified in a Prospectus Supplement), the underwriters or agents may over-allot or effect transactions which stabilize, maintain or otherwise affect the market price of the Securities offered at levels other than those which might otherwise prevail on the open market. These transactions may be commenced, interrupted or discontinued at any time.

SELLING SHAREHOLDER

General

The Province is the principal shareholder of Hydro One Limited. As of March 29, 2016, the Province beneficially owned or exercised control over (i) 500,103,660 Common Shares, representing approximately 84% of the issued and outstanding Common Shares; and (ii) 16,720,000 Series 1 Preferred Shares, representing 100% of the issued and outstanding Preferred Shares. Such Common Shares and Series 1 Preferred Shares are owned both of record and beneficially by the Province. See "**Prior Sales**" for information on the Common Shares and Series 1 Preferred Shares acquired by the Province preceding the date of this Prospectus.

The terms under which the Common Shares and/or Preferred Shares will be offered by the Selling Shareholder will be described in the applicable Prospectus Supplement. The Prospectus Supplement concerning any offering of the Common Shares and/or Preferred Shares by the Selling Shareholder will include, without limitation, where applicable: (i) the name(s) of the Selling Shareholder; (ii) the number of Common Shares and/or Preferred Shares, as applicable, owned, controlled or directed by the Selling Shareholder; (iii) the number of Common Shares and/or Preferred Shares, as applicable, being distributed for the account of the Selling Shareholder; (iv) the number of Common Shares and/or Preferred Shares, as applicable, to be owned, controlled or directed by the Selling Shareholder after the distribution and the percentage that number or amount represents out of the total number of outstanding Common Shares and/or Preferred Shares, as applicable; (v) whether the Common Shares and/or Preferred Shares, as applicable, are owned by the Selling Shareholder both of record and beneficially, of record only or beneficially only; (vi) if the Selling Shareholder purchased any of the Common Shares and/or Preferred Shares, as applicable, held by it in the 24 months preceding the date of the applicable Prospectus Supplement, the date or dates the Selling Shareholder acquired the Common Shares and/or Preferred Shares, as applicable; and (vii) if the Selling Shareholder acquired the Common Shares and/or Preferred Shares, as applicable, held by it in the 12 months preceding the date of the applicable Prospectus Supplement, the cost thereof to the Selling Shareholder in the aggregate and on a per security basis.

During the 25 months that this Prospectus remains valid, the Selling Shareholder may offer and sell Common Shares and/or Preferred Shares pursuant to this Prospectus. The Selling Shareholder may also sell Common Shares and/or Preferred Shares other than pursuant to this Prospectus under available exemptions from the prospectus requirements of Canadian securities legislation. The Selling Shareholder may sell none, some or all of the Common Shares and/or Preferred Shares qualified for distribution by it pursuant to this Prospectus. Hydro One Limited cannot predict when or in what amounts the Selling Shareholder may sell any of the Common Shares and/or Preferred Shares qualified for distribution by this Prospectus.

The Province has indicated that it intends to sell Common Shares over time, until it holds approximately 40% of Hydro One Limited. The *Electricity Act, 1998* (Ontario) (the "**Electricity Act**") restricts the Province from selling securities of Hydro One Limited carrying a voting right either under all circumstances or under some circumstances that have occurred and are continuing ("**Voting Securities**") (including Common Shares of Hydro One Limited) if it would own less than 40% of the outstanding number of Voting Securities of that class or series after the sale. If as a result of the issuance of additional Voting Securities by Hydro One Limited, the Province owns less than 40% of the outstanding number of Voting Securities of any class or series, the Province must, subject to the approval of the Lieutenant Governor in Council and the necessary appropriations from the Legislature, take steps to acquire as many Voting Securities of that class or series as are necessary to increase the Province's ownership to not less than 40% of the outstanding number of Voting Securities of that class or series. The manner in which, and the time by which, the Province must acquire these additional Voting Securities will be determined by the Lieutenant Governor in Council.

The Province has been granted pre-emptive rights by Hydro One Limited to assist it in meeting its ownership requirements under the Electricity Act as described in the documents incorporated by reference in this Prospectus.

In connection with the completion of the initial public offering of Hydro One Limited, on November 5, 2015, Hydro One and the Province entered into (i) a governance agreement (the "**Governance Agreement**") to address the Province's role in the governance of Hydro One Limited, and (ii) a registration rights agreement (the "**Registration Rights Agreement**") to provide the Province with the right to require Hydro One Limited to facilitate future secondary offerings of Common Shares or Preferred Shares owned or controlled by the Province.

The material terms of the Governance Agreement are summarized in the documents incorporated by reference in this Prospectus and the material terms of the Registration Rights Agreement are summarized below. A copy of each of the Governance Agreement and the Registration Rights Agreement has been filed on SEDAR and is available under Hydro One Limited's profile at www.sedar.com. The discussion in this Prospectus and in the documents incorporated by reference in this Prospectus concerning the Governance Agreement and the Registration Rights Agreement is not complete, and is qualified in its entirety to the text of the Governance Agreement and the Registration Rights Agreement, each of which should be referred to.

Registration Rights Agreement

Pursuant to the Registration Rights Agreement, Hydro One Limited has granted the Province certain demand registration rights providing that, from time to time while the Province is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, the Province can require Hydro One Limited to file, at the expense of the Province (except for internal expenses of Hydro One Limited or other expenses that Hydro One Limited would have incurred even in the absence of such a request), and subject to certain exceptions, one or more prospectuses and take other procedural steps as may be reasonably necessary to facilitate a secondary offering in Canada of all or any portion of the Common Shares or Preferred Shares held by the Province.

If Hydro One Limited proposes to undertake a Canadian public offering by prospectus, the Province is entitled, while it is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, to include Common Shares or Preferred Shares owned by it as part of that offering, provided that the underwriters may reduce the number of Common Shares or Preferred Shares proposed to be sold if in their reasonable judgment all of the Common Shares or Preferred Shares proposed to be offered by Hydro One Limited and the Province may not be sold in an orderly manner within a price range reasonably acceptable to Hydro One Limited. In that case, the Common Shares or Preferred Shares to be sold will be allocated pro rata between Hydro One Limited and the Province based on their relative proportionate number of Common Shares or Preferred Shares requested to be included in the offering. Hydro One Limited and the Province will share the expenses of the offering (except for internal expenses of Hydro One Limited) in proportion to the gross proceeds they each receive from the offering.

Hydro One Limited has also agreed to use commercially reasonable efforts to assist the Province, at the Province's expense, in any sale by it of Common Shares or Preferred Shares of Hydro One Limited pursuant to an exemption from the prospectus requirements, in the preparation of an offering memorandum and other documentation and by facilitating due diligence by the prospective buyer.

Hydro One Limited and the Province have also agreed to enter into customary agreements, including "lock-up" agreements, on customary market terms in connection with such transactions. Hydro One Limited also agreed to certain indemnification and contribution covenants in favour of the Province and any underwriters involved in such transactions.

Under the Registration Rights Agreement, the Province can designate any "public entity" (as defined in the *Financial Administration Act* (Ontario)) that beneficially owns or exercises control or direction over Common Shares or Preferred Shares as being entitled to the rights and benefits of the Province under the Registration Rights Agreement. References in this Prospectus to "Selling Shareholder" shall mean to refer to any such entity designated by the Province from time to time.

DESCRIPTION OF SHARE CAPITAL

The following is a summary of the material attributes and characteristics of Hydro One Limited's authorized share capital, including the Common Shares and Preferred Shares that may be offered and sold from time to time under this Prospectus. The following summary is not complete and is subject to, and qualified in its entirety by reference to, the terms and provisions of Hydro One Limited's articles, as they may be amended from time to time, which are available under Hydro One Limited's profile on SEDAR at www.sedar.com.

Hydro One Limited's authorized share capital consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series, of which 595,000,000 Common Shares, 16,720,000 Series 1 Preferred Shares and no Series 2 Preferred Shares are issued and outstanding as of the date of this Prospectus.

Common Shares

Holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders, except meetings at which only the holders of another class or series of shares are entitled to vote separately as a class or series, and holders of Common Shares are entitled to one vote per share at all such meetings of shareholders. Hydro One Limited's Common Shares are not redeemable or retractable. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 Preferred Shares and Series 2 Preferred Shares, holders of Common Shares are entitled to receive dividends if, as, and when declared by the board of directors (the "**Board**") of Hydro One Limited. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 Preferred Shares and Series 2 Preferred Shares, holders of Common Shares are also entitled to receive the remaining assets of Hydro One Limited upon its liquidation, dissolution or winding-up or other distribution of Hydro One Limited's assets for the purposes of winding-up its affairs.

Voting Securities, which include the Common Shares, are subject to share ownership restrictions under the Electricity Act. The share ownership restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds Voting Securities solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities of Hydro One Limited. The articles of Hydro One Limited provide for comprehensive enforcement mechanisms that are applicable in the event of a contravention of the share ownership requirements.

Preferred Shares

Hydro One Limited may from time to time issue Preferred Shares in one or more series. Prior to issuing shares in a series, the Board is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of Preferred Shares.

Subject to the OBCA, holders of Preferred Shares or a series thereof are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One Limited except that votes may be granted to a series of Preferred Shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of Preferred Shares ranks on parity with every other series of Preferred Shares with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited. The Preferred Shares are entitled to a preference over the Common Shares and any other shares ranking junior to the preferred shares with respect to payment of dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited.

As of the date of this Prospectus, Hydro One Limited has authorized for issuance two series of Preferred Shares: (i) the Series 1 Preferred Shares and (ii) the Series 2 Preferred Shares, of which 16,720,000 Series 1 Preferred Shares and no Series 2 Preferred Shares are issued and outstanding as of the date of this Prospectus. The material terms of the Series 1 Preferred Shares and the Series 2 Preferred Shares are summarized below. With respect to any offering of Series 1 Preferred Shares and/or Series 2 Preferred Shares, any amendments to the terms described herein, and the offering price of such Series 1 Preferred Shares and/or Series 2 Preferred Shares, together with any other terms then material to the offering of Series 1 Preferred Shares and/or Series 2 Preferred Shares will be described in the Prospectus Supplement filed in respect of the offering of such Series 1 Preferred Shares and/or Series 2 Preferred Shares.

The particular terms and provisions of any other series of Preferred Shares offered pursuant to any Prospectus Supplement, and the extent to which the general terms and provisions described below may apply to them, will be described in the Prospectus Supplement filed in respect of the offering of such series of Preferred Shares. This description may include, without limitation and as applicable: (i) the offering price of the series of Preferred Shares; (ii) the title, designation and number of shares of the series of Preferred Shares; (iii) the dividend rate or method of calculation, the payment dates for dividends and whether dividends will be cumulative or noncumulative, and, if cumulative, the dates from which dividends will begin to accumulate; (iv) any conversion or exchange features or rights; (v) whether the series of Preferred Shares will be subject to redemption and the redemption price and other terms and conditions relative to the redemption rights; (vi) any sinking fund provisions; (vii) the circumstances in which the series of Preferred Shares will have voting rights, if any; (vii) any other rights, privileges, restrictions and conditions attaching to the series of Preferred Shares; and (viii) any other specific terms that are material to such series of Preferred Shares.

Series 1 Preferred Shares and Series 2 Preferred Shares

The following is a summary of the material terms of the Series 1 Preferred Shares and Series 2 Preferred Shares.

For the period commencing from October 31, 2015 and ending on and including November 19, 2020, the holders of Series 1 Preferred Shares will be entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board, payable quarterly on the 20th day of November, February, May and August in each year. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 Preferred Shares will not be redeemable by Hydro One Limited prior to November 20, 2020, but will be redeemable by Hydro One Limited on November 20, 2020 and on November 20 every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 Preferred Share redeemed, plus any accrued or unpaid dividends.

The holders of Series 1 Preferred Shares will have the right, at their option, on November 20, 2020 and on November 20 every fifth year thereafter, to convert all or any of their Series 1 Preferred Shares into Series 2 Preferred Shares on a one-for-one basis, subject to certain restrictions on conversion.

The holders of Series 2 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 Preferred Shares will be redeemable by Hydro One Limited at a redemption price equal to $25.00 for each Series 2 Preferred Share redeemed if redeemed on November 20, 2025 or on November 20 every fifth year thereafter or $25.50 for each Series 2 Preferred Share redeemed if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 Preferred Shares will have the right, at their option, on November 20, 2025 and on November 20 every fifth year thereafter, to convert all or any of their Series 2 Preferred Shares into Series 1 Preferred Shares on a one-for-one basis, subject to certain restrictions on conversion.

In the event of the liquidation, dissolution or winding-up of Hydro One Limited, or any other distribution of assets of Hydro One Limited for the purpose of winding-up its affairs, the holders of Series 1 Preferred Shares and Series 2 Preferred Shares will be entitled to receive $25.00 for each Series 1 Preferred Share and each Series 2 Preferred Share held by them, plus any unpaid dividends, before any amounts are paid or any assets of Hydro One Limited are distributed to holders of Common Shares and any shares ranking junior to the Series 1 Preferred Shares and Series 2 Preferred Shares. After payment of those amounts, the holders of Series 1 Preferred shares and Series 2 Preferred shares will not be entitled to share in any further distribution of the property or assets of Hydro One Limited.

Except as required by the OBCA, neither the holders of Series 1 Preferred Shares nor the holders of Series 2 Preferred Shares shall be entitled to receive notice of, or to attend meetings of shareholders of Hydro One Limited and shall not be entitled to vote at any such meeting, unless Hydro One Limited fails for eight quarters, whether or not consecutive, to pay in full the dividends payable on the Series 1 Preferred Shares or Series 2 Preferred Shares, as applicable, whereupon the holders of Series 1 Preferred Shares and Series 2 Preferred Shares, as applicable, shall become entitled to receive notice of and attend all meetings of shareholders, except class meetings of any other class of shares, and shall have one vote for each Series 1 Preferred Share or Series 2 Preferred Share held at such meetings, as applicable.

DESCRIPTION OF DEBT SECURITIES

The following sets forth certain general terms and provisions of the Debt Securities. The particular terms and provisions of Debt Securities offered pursuant to any Prospectus Supplement, and the extent to which the general terms and provisions described below may apply to them, will be described in the Prospectus Supplement filed in respect of such Debt Securities.

The Debt Securities will be issued under one or more indentures or supplements thereto (as applicable, the "**Indenture**") between Hydro One Limited and a trustee. The statements made hereunder relating to the Indenture and the Debt Securities to be issued thereunder are summaries of certain anticipated provisions thereof and do not purport to be complete and are subject to, and are qualified in their entirety by reference to, all provisions of the Indenture.

The Debt Securities will be direct obligations of Hydro One Limited and may be guaranteed by some or all subsidiaries of Hydro One Limited. The Debt Securities will be senior or subordinated indebtedness of Hydro One Limited and may be secured or unsecured. Unless otherwise provided in the applicable Prospectus Supplement, a series of Debt Securities may be reopened for the issuance of additional Debt Securities of such series.

The particular terms of each issue of Debt Securities will be described in the related Prospectus Supplement. Such description will identify the trustee under the Indenture pursuant to which the Debt Securities are to be issued, and will include, where applicable:

- the designation and aggregate principal amount of the Debt Securities;
- any limit on the aggregate principal amount of the Debt Securities;
- the authorized denominations of the Debt Securities;
- the currency or currency units for which the Debt Securities may be purchased and the currency or currency units in which the principal and any interest is payable (in either case, if other than Canadian dollars);
- the price at which the Debt Securities will be issued or whether the Debt Securities will be issued on a non-fixed price basis;
- the date or dates on which the Debt Securities will mature;
- the rate or rates per annum (which may be fixed or variable) at which the Debt Securities will bear interest (if any), or the method of determination of such rates (if any);
- the dates on which any such interest will be payable and the record dates for such payments;
- whether the Debt Securities will be subject to redemption or call, and, if so, the terms of such redemption or call provisions;

- whether the Debt Securities will be subject to any sinking fund provisions;
- the ranking of the Debt Securities relative to the other debt of Hydro One Limited and the terms of the subordination of any subordinated Debt Securities;
- whether or not the Debt Securities will be secured or unsecured, and the terms of any security provided;
- whether the Debt Securities are convertible or exchangeable into other Securities and the terms of conversion or exchange;
- any terms relating to the modification, amendment or waiver of any terms of such Debt Securities or the applicable Indenture;
- covenants relating to the payment of principal and interest on the Debt Securities and other covenants applicable to such Debt Securities;
- the events of default applicable to the Debt Securities;
- whether or not the Debt Securities will be guaranteed by some or all of the subsidiaries of Hydro One Limited, and the terms of any such guarantees; and
- any other material terms and conditions of the Debt Securities.

Debt Securities may, at the option of Hydro One Limited, be issued in fully registered form, in "book-entry only" form or they may be uncertificated, which will be set forth in the applicable Prospectus Supplement along with a description of the applicable ownership (including beneficial ownership), transfer and exchange provisions.

Debt Securities may be offered separately or together with other Securities under this Prospectus and may be convertible or exchangeable into other Securities under this Prospectus.

DESCRIPTION OF SUBSCRIPTION RECEIPTS

The following sets forth the general terms of the Subscription Receipts. The particular terms and provisions of Subscription Receipts offered pursuant to any Prospectus Supplement, and the extent to which the general terms and provisions described below may apply to them, will be described in the Prospectus Supplement filed in respect of such offering of Subscription Receipts. Subscription Receipts may be offered separately or together with other Securities. The Subscription Receipts will be issued under one or more subscription receipt agreements that will be entered into by Hydro One Limited and an escrow or other agent at the time of issuance of the Subscription Receipts.

Subscription Receipts will entitle the holder thereof to receive other Securities (typically Common Shares), for no additional consideration, upon the completion of a particular transaction or event, typically an acquisition of the assets or securities of another entity by the Company. The subscription proceeds from an offering of Subscription Receipts will be held in escrow by an escrow or other agent pending the completion of the transaction or the termination time (the time at which the escrow terminates regardless of whether the transaction or event has occurred). Holders of Subscription Receipts will receive other Securities upon the completion of the particular transaction or event or, if the transaction or event does not occur by the termination time, a return of the subscription funds for their Subscription Receipts together with any interest or other income earned thereon. Subscription Receipts may be offered independently or together with other Securities.

Holders of Subscription Receipts are not shareholders of Hydro One Limited. The particular terms and provisions of Subscription Receipts offered by this Prospectus will be described in the Prospectus Supplement filed in respect of the offering of such Subscription Receipts. This description may include, without limitation and as applicable: (i) the number of Subscription Receipts offered; (ii) the price at which the Subscription Receipts will be offered; (iii) the terms, conditions and procedures pursuant to which the holders of Subscription Receipts will become entitled to receive other Securities; (iv) the number of other Securities that may be obtained pursuant to each Subscription

Receipt; (v) the designation and terms of any other Securities with which the Subscription Receipts will be offered, if any, and the number of Subscription Receipts that will be offered with each such Security; (vi) the terms relating to the holding and release of the gross proceeds from the sale of the Subscription Receipts plus any interest and income earned thereon; (vii) the material income tax consequences of owning, holding and disposing of the Subscription Receipts; and (viii) any other material terms and conditions of the Subscription Receipts including, without limitation, transferability and adjustment terms and whether the Subscription Receipts will be listed on a securities exchange.

DESCRIPTION OF WARRANTS

The following sets forth the general terms and conditions of the Warrants. The particular terms and provisions of Warrants offered pursuant to any Prospectus Supplement, and the extent to which the general terms and provisions described below may apply to them, will be described in the Prospectus Supplement filed in respect of such offering of Warrants. The Warrants either will be issued under a warrant indenture or agreement that will be entered into by Hydro One Limited and a trustee or warrant agent at the time of issuance of the Warrants or will be represented by warrant certificates issued by Hydro One Limited.

Warrants will entitle the holder thereof to receive other Securities (typically Common Shares or Preferred Shares) upon the exercise thereof and payment of the applicable exercise price. A Warrant is typically exercisable for a specific period of time at the end of which time it will expire and cease to be exercisable. Warrants may be offered independently or together with other Securities and may be attached to, or separate from, any such offered Securities.

Holders of Warrants are not shareholders of Hydro One Limited. The particular terms and provisions of Warrants offered by this Prospectus will be described in the Prospectus Supplement filed in respect of the offering of such Warrants. This description may include, without limitation and as applicable: (i) the title or designation of the Warrants; (ii) the number of Warrants offered and the offering price thereof; (iii) the number of other Securities purchasable upon exercise of the Warrants and the procedures for exercise; (iv) the exercise price of the Warrants; (v) the dates or periods during which the Warrants are exercisable and when they expire; (vi) the designation and terms of any other Securities with which the Warrants will be offered, if any, and the number of Warrants that will be offered with each such Security; (vii) the material income tax consequences of owning, holding and disposing of the Warrants; and (viii) any other material terms and conditions of the Warrants including, without limitation, transferability and adjustment terms and whether the Warrants will be listed on a securities exchange.

DESCRIPTION OF UNITS

The following sets for the general terms and conditions of the Units. The particular terms and provisions of the Units offered by any Prospectus Supplement, and the extent to which the general terms and provisions described below may apply to them, will be described in the Prospectus Supplement filed in respect of such offering of Units. Units are securities consisting of one or more of the other Securities described in this Prospectus offered together as a "Unit". A Unit is typically issued such that the holder thereof is also the holder of each Security included in the Unit. Thus, the holder of a Unit will have the rights and obligations of a holder of each Security comprising the Unit. The unit agreement under which a Unit is issued may provide that the Securities comprising the Unit may not be held or transferred separately at any time or at any time before a specified date.

The particular terms and provisions of Units offered by this Prospectus will be described in the Prospectus Supplement filed in respect of the offering of such Units. This description may include, without limitation and as applicable: (i) the designation and terms of the Units and of the Securities comprising the Units, including whether and under what circumstances those Securities may be held or transferred separately; (ii) any provisions for the issuance, payment, settlement, transfer or exchange of the Units or of the Securities comprising the Units; (iii) whether the Units will be issued in fully registered or global form; and (iv) any other material terms and conditions of the Units.

PRIOR SALES

On August 31, 2015, in connection with the incorporation of Hydro One Limited, Hydro One Limited issued 100,000 Common Shares to the Province at a subscription price of $1.00 per share for an aggregate subscription price of $100,000.

On October 31, 2015, Hydro One Limited issued Common Shares and 16,720,000 Series 1 preferred shares to the Province as consideration for the acquisition of all of the issued and outstanding shares of Hydro One Inc. by Hydro One Limited from the Province.

Prior to the closing of its initial public offering, Hydro One Limited established two share grant plans, one for the benefit of certain members of the Power Workers' Union (the "**PWU Share Grant Plan**") and one for the benefit of certain members of The Society of Energy Professionals (the "**Society Share Grant Plan**"). Both plans provide for the issuance of Common Shares from treasury to certain eligible members of such unions over a number of years, such number of Common Shares to be determined by reference to a portion of each eligible member's salary and $20.50, the offering price of the Common Shares in the initial public offering. The maximum number of Common Shares issuable under the PWU Share Grant Plan is 3,981,763 Common Shares and the maximum number of Common Shares issuable under the Society Share Grant Plan is 1,434,686 Common Shares. On November 2, 2015 rights to receive such Common Shares were granted to participants under both plans. For details of the share grant plans and the grants made, see Note 21 to the 2015 Annual Financial Statements.

On November 4, 2015, the Province subscribed for an additional 2,600,000,000 Common Shares at a subscription price of $1.00 per share for an aggregate subscription price of $2,600,000,000 in connection with the funding of the departure tax payable as a consequence of the initial public offering of Hydro One Limited.

The outstanding Common Shares were consolidated on November 4, 2015 such that 595,000,000 Common Shares were issued and outstanding immediately prior to the closing of the initial public offering.

On November 5, 2015, Hydro One Limited completed its initial public offering by way of a secondary offering of 81,100,000 common shares by the Province at a price of $20.50 per share for aggregate gross proceeds to the Province of $1,662,550,000. On November 12, 2015, the underwriters in the initial public offering exercised their option to purchase an additional 8,150,000 Common Shares from the Province at a price of $20.50 per share for additional aggregate gross proceeds to the Province of $167,075,000. Hydro One Limited did not receive any proceeds from the initial public offering.

Following the closing of the initial public offering, on November 5, 2015, the Province sold 3,756,097 Common Shares to two trusts established for the benefit of the Power Workers' Union at a price per share of $20.50. Following closing of the initial public offering, on November 5, 2015 and November 17, 2015, the Province sold an aggregate of 1,890,243 Common Shares to two trusts established for the benefit of The Society of Energy Professionals, in each case at a price per share of $20.50.

TRADING PRICE AND VOLUME

The Common Shares are listed on the TSX and commenced trading under the symbol "H" on November 5, 2015. The following table sets forth the reported high and low sales prices and the trading volumes for the Common Shares as reported by the TSX for each month beginning with the partial month from November 5, 2015, being the date of the closing of Hydro One Limited's initial public offering:

Period	High ($)	Low ($)	Volume
November 5, 2015 to November 30, 2015…………	23.15	21.01	31,005,159
December 2015 ……………………………………	22.95	21.53	7,060,538
January 2016 ………………………………………	22.60	21.85	3,929,776
February 2016 ……………………………………...	23.31	21.90	4,489,699
March 1, 2016 to March 29, 2016……..………	24.25	23.15	6,961,843

CERTAIN INCOME TAX CONSIDERATIONS

The applicable Prospectus Supplement may describe certain Canadian federal income tax considerations generally applicable to investors of purchasing, holding and disposing of the Securities offered thereunder.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase Securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment, irrespective of the determination at a later date of the purchase price of the Securities distributed if offered on a non-fixed price basis. In several of the provinces and territories, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

In an offering of convertible, exchangeable or exercisable Securities, investors are cautioned that the statutory right of action for damages for a misrepresentation contained in the Prospectus is limited, in certain provincial and territorial securities legislation, to the price at which the convertible, exchangeable or exercisable securities are offered to the public under this Prospectus. This means that, under the securities legislation of certain provinces and territories of Canada, if the purchaser pays additional amounts upon the conversion, exchange or exercise of the Security, those amounts may not be recoverable under the statutory right of action for damages that applies in those provinces or territories. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

Original purchasers of convertible, exchangeable or exercisable Securities under this Prospectus will have a contractual right of rescission against Hydro One Limited in respect of the conversion, exchange or exercise of such Securities, as the case may be. This contractual right of rescission will entitle such original purchasers to receive the amount paid upon conversion, exchange or exercise, upon surrender of the underlying Securities gained thereby, in the event that this Prospectus (as supplemented or amended) contains a misrepresentation, provided that: (i) the conversion, exchange or exercise takes place within 180 days of the date of the purchase of the convertible, exchangeable or exercisable Security under this Prospectus; and (ii) the right of rescission is exercised within 180 days of the date of the purchase of the convertible, exchangeable or exercisable Security under this Prospectus. This contractual right of rescission will be consistent with the statutory right of rescission described under section 130 of the *Securities Act* (Ontario), and is in addition to any other right or remedy available to original purchasers under section 130 of the *Securities Act* (Ontario) or otherwise at law. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

To the extent the Selling Shareholder is offering and selling Common Shares or Preferred Shares pursuant to this Prospectus, certain remedies, including statutory rights for rescission or damages, may not be available against the Province. See "Risk Factors — Potential Difficulties in Enforcing Civil Liabilities Against the Province". The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

EXEMPTIONS

On August 27, 2015, Hydro One Inc. obtained a decision from the Ontario Securities Commission, as principal regulator, on behalf of itself and the securities regulatory authorities in each of the other provinces and territories of Canada, exempting Hydro One Limited from the requirements in section 3.2 of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* which requires financial statements to be prepared in accordance with and disclosed in compliance with International Financial Reporting Standards. The decision granting the exemption permits Hydro One Limited to prepare and present its financial statements required to be filed with the securities regulatory authorities in each of the provinces and territories of Canada (including financial statements included in any prospectus of Hydro One Limited) in accordance with U.S. GAAP until the earliest to occur of the following:

(a) January 1, 2019;

(b) if Hydro One Limited ceases to have activities subject to rate regulation, the first day of Hydro One Limited's financial year commencing after its ceases to have such activities subject to rate regulation; and

(c) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

The exemption was requested: (i) due to continuing uncertainty of accounting treatment and lack of a specific mandatory standard for entities with activities subject to rate regulation under International Financial Reporting Standards; (ii) because U.S. GAAP provides a more suitable set of accounting principles for entities with activities subject to rate regulation and is more consistent with those prescribed by the Ontario Energy Board in its Accounting Procedures Handbook for Electric Distribution Utilities; and (iii) to ensure consistency with and comparability to the financial statements of Hydro One Inc. which reports in U.S. GAAP, as well as Hydro One Limited's industry peers that currently report in U.S. GAAP.

AGENT FOR SERVICE OF PROCESS IN CANADA

Kathryn Jackson, a director of Hydro One Limited, resides outside of Canada. Ms. Jackson has appointed Hydro One Limited as agent for service of process at 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person who resides outside of Canada, even if the party has appointed an agent for service of process.

LEGAL MATTERS

Unless otherwise indicated in the Prospectus Supplement relating to an offering of Securities, the particular offering of Securities will be subject to approval of certain legal matters on behalf of Hydro One Limited by Osler, Hoskin & Harcourt LLP. As of the date of this Prospectus, the partners and associates of Osler, Hoskin & Harcourt LLP, as a group, beneficially owned, directly or indirectly, less than 1% of outstanding securities of any class issued by Hydro One Limited. In addition, certain legal matters in connection with any offering of Securities will be passed upon for any underwriters, agents or the Selling Shareholder, as applicable, by counsel to be designated at the time of the offering.

AUDITORS, TRANSFER AGENT AND REGISTRAR

KPMG LLP, Chartered Professional Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario, M5H 2S5, is the auditor of Hydro One Limited and has confirmed that it is independent of Hydro One Limited within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

Computershare Trust Company of Canada at its principal office in Toronto, Ontario is the transfer agent and registrar for the Common Shares.

PROMOTERS

Hydro One Inc. has taken the initiative in founding and organizing Hydro One Limited and may therefore be considered a promoter of Hydro One Limited for the purposes of applicable securities legislation. In connection with a series of pre-closing transactions completed in connection with the initial public offering of Hydro One Limited, on October 31, 2015, Hydro One Limited acquired all of the issued and outstanding common shares of Hydro One Inc. from the Province in exchange for the issuance to the Province of 16,720,000 Series 1 Preferred Shares and 12,197,500,000 Common Shares. For further details concerning the relationship between Hydro One Limited and Hydro One Inc., see the documents incorporated by reference in this Prospectus.

Although the Province executed a certificate page as a promoter of Hydro One Limited for purposes of Hydro One Limited's initial public offering, as a result of the entering into of the Governance Agreement and completion of the initial public offering, Hydro One Limited no longer believes the Province is a promoter of Hydro One Limited. For further details concerning the Province's relationship with Hydro One Limited, please see "Selling Shareholder" and "Prior Sales" above and the documents incorporated by reference in this Prospectus.

CERTIFICATE OF HYDRO ONE LIMITED AND HYDRO ONE INC.

Dated: March 30, 2016

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus and the supplement(s) as required by the securities legislation of each of the provinces and territories of Canada.

HYDRO ONE LIMITED

(signed) MAYO SCHMIDT President and Chief Executive Officer	(signed) MICHAEL VELS Chief Financial Officer

On behalf of the Board of Directors:

(signed) DAVID DENISON Director	(signed) PHILIP ORSINO Director

HYDRO ONE INC.
(as promoter)

(signed) MAYO SCHMIDT President and Chief Executive Officer	(signed) MICHAEL VELS Chief Financial Officer

On behalf of the Board of Directors:

(signed) DAVID DENISON Director	(signed) PHILIP ORSINO Director

Secondary Offering **August 1, 2017**

SHORT FORM PROSPECTUS

HYDRO ONE LIMITED

$1,400,000,000
4.00% Convertible Unsecured Subordinated Debentures represented by Instalment Receipts

The 4.00% convertible unsecured subordinated debentures (the "Debentures") of Hydro One Limited ("Hydro One Limited", or the "Corporation") offered hereby (the "Offering") will be sold by 2587264 Ontario Inc. (the "Selling Debentureholder"), a direct wholly-owned subsidiary of Hydro One Limited, on an instalment basis at a price of $1,000 per Debenture. See "Details of the Offering – The Selling Debentureholder". Prior to full payment, beneficial ownership of the Debentures will be represented by instalment receipts (the "Instalment Receipts"). The first instalment of $333 is payable on the closing of the Offering. The final instalment of $667 is payable following notification to holders of Instalment Receipts (the "Final Instalment Notice") that: (i) the Corporation has received all regulatory and governmental approvals required to finalize the direct or indirect acquisition (the "Merger") by Olympus Holding Corp. ("US Parent"), an indirect, wholly-owned subsidiary of the Corporation, of Avista Corporation, an investor-owned, regulated utility company whose common stock is listed on the New York Stock Exchange ("NYSE"); and (ii) US Parent and Avista Corporation have fulfilled or waived all other outstanding conditions precedent to closing the Merger, other than those which by their nature cannot be satisfied until the closing of the Merger (collectively, the "Approval Conditions"), in each case as set out in the agreement and plan of merger dated as of July 19, 2017 among Hydro One Limited, US Parent, Olympus Corp. ("Merger Sub"), a direct wholly-owned subsidiary of US Parent and, at the effective time of the closing of the Merger, will be collectively owned by US Parent and one or more direct or indirect wholly-owned subsidiaries of the Corporation, and Avista Corporation (the "Merger Agreement"). See "The Merger" and "The Merger Agreement". The Final Instalment Notice will set a date for payment of the final instalment (the "Final Instalment Date"), which shall not be less than 15 days nor more than 90 days following the date of such notice. **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debenture represented by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement (as defined under "Details of the Offering – Instalment Receipts"), be forfeited to the Selling Debentureholder in full satisfaction of the holder's obligations or such**

Debentures may be sold and the holder will remain liable for any deficiency in the proceeds of such sale. See "Details of the Offering".

The holders of Debentures will be entitled to interest at an annual rate of 4.00% per $1,000 principal amount of Debentures, payable quarterly in arrears in equal instalments (other than the first interest payment and, depending on the Final Instalment Date, the final interest payment) on the last day of, December, March, June and September of each year (or the prior business day if the last day falls on a weekend or holiday) to and including the Final Instalment Date. The first interest payment will be made on December 29, 2017 in the amount of $15.78082 per $1,000 principal amount of Debentures and will include interest payable from and including the closing of the Offering, which is expected to take place on or about August 9, 2017 (the "Closing Date"). Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures. **On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures.** Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12.0%, and the effective annual yield thereafter is 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date.

Conversion Privilege

At the option of the holder of Debentures and provided that payment of the final instalment has been made, each Debenture will be convertible into common shares of Hydro One Limited ("Common Shares") at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date (as defined in this Prospectus). The conversion price will be $21.40 per Common Share (the "Conversion Price"), being a conversion rate of 46.7290 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. **A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment in order to convert its Debentures to Common Shares on the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. See "Details of the Offering".**

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest (without any Make-Whole Payment) following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Merger Agreement in accordance with its terms; and (iii) May 1, 2019, if the Final Instalment Notice has not been given on or before April 30, 2019. Upon any such redemption, the Corporation will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Hydro One Limited has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will at all times hold short-term interest bearing U.S. dollar securities with investment grade counterparties, maintain readily available capacity under the Operating Credit Facility (as defined in this Prospectus) or the revolving credit facilities of its subsidiaries, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering and the exercise of the Over-Allotment Option (as defined in this Prospectus), if applicable. See "Details of the Offering — Debentures — Redemption". After the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed at the option of the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. See "Details of the Offering – Debentures – Redemption".

On September 30, 2027 (the "Maturity Date"), the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash, provided that the Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the weighted average trading price of the Common Shares on the Toronto Stock Exchange (the "TSX") for the 20 consecutive trading days ending five trading days preceding the Maturity Date (the "Market Price").

Price: $1,000 per Debenture to yield 4.00% per annum

(each Debenture is convertible into Common Shares at a Conversion Price of $21.40 per Common Share)

	Price to the Public	Underwriters' Fee(1)	Net Proceeds(2)
Per Debenture			
First Instalment	$ 333.00	$ 17.50	$ 315.50
Final Instalment	$ 667.00	$ 17.50	$ 649.50
Total Per Debenture	$ 1,000.00	$ 35.00	$ 965.00
Total(3)	$ 1,400,000,000	$ 49,000,000	$ 1,351,000,000

(1) The Underwriters' fee will be paid by the Corporation and is equal to 3.50% of the gross proceeds of the sale of the Debentures. One-half of the Underwriters' fee is payable on the Closing Date and the remaining one-half is payable on the Final Instalment Date.

(2) Net proceeds are calulated before deducting the expenses of the Offering, estimated at $1,500,000, which will be paid by Hydro One Limited and the Selling Debentureholder.

(3) The Selling Debentureholder has granted to the Underwriters (as defined in this Prospectus) an option (the "Over-Allotment Option") to purchase additional Debentures represented by Instalment Receipts equal to up to 10% of the aggregate principal amount of Debentures represented by Instalment Receipts sold on the Closing Date, at a price of $1,000 per Debenture payable on an instalment basis and on the same terms and conditions of the Offering to cover over-allotments, if any, and for market stabilization purposes. The Over-Allotment Option is exercisable in whole or in part at the Underwriters' sole discretion and without obligation, on or prior to the 30th day following the closing of the Offering. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Fee" and "Net Proceeds" will be $1,540,000,000, $53,900,000 and $1,486,100,000, respectively. This Prospectus qualifies the grant of the Over-Allotment Option and the sale of Debentures represented by Instalment Receipts pursuant to this Prospectus on the exercise of such option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those securities under this Prospectus, regardless of whether the position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. Unless otherwise indicated, the disclosure in this Prospectus assumes that the Over-Allotment Option has not been exercised. See "Plan of Distribution".

Underwriters' Position	Maximum Size or Number of Securities Held	Exercise Period	Exercise Price
Over-Allotment Option	Option to purchase up to $140,000,000 aggregate principal amount of Debentures (on an instalment basis)	At any time within 30 days following the closing of the Offering	$1,000 per Debenture payable on an instalment basis of which $333 is payable on the closing of the Over-Allotment Option and $667 is payable on or before the Final Instalment Date

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".

This Prospectus qualifies for distribution the Debentures represented by the Instalment Receipts. Hydro One Limited has received conditional approval of the TSX to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX. **The Corporation has no current intention to list the Debentures for trading on any exchange as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date.** The Corporation's outstanding Common Shares are listed on the TSX under the symbol "H", and, once listed, the Instalment Receipts will trade on the TSX under the symbol "H.IR". On July 19, 2017, the last trading day prior to the announcement of the Merger and the Offering, the closing price of the Common Shares on the TSX was $22.53.

The Debentures will be sold by the Selling Debentureholder on an instalment basis for a total of $1,000 per Debenture as described in this Prospectus, which price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters. **After a reasonable effort has been made to sell all of the Debentures represented by Instalment Receipts at the price specified above, the Underwriters may subsequently reduce the selling price to investors from time to time in order to sell any of the Debentures represented by Instalment Receipts remaining unsold. Any such reduction will not affect the proceeds received by the Selling Debentureholder. See "Plan of Distribution".**

An investment in the Debentures represented by Instalment Receipts, and the Common Shares issuable upon the conversion of Debentures, involves certain risks that should be considered by a prospective purchaser. See "Risk Factors – Risk Factors Relating to the Debentures", "Risk Factors – Risk Factors Relating to the Instalment Receipts" and "Special Note Regarding Forward-Looking Statements".

Each of RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., Barclays Capital Canada Inc., Credit Suisse Securities (Canada), Inc., Canaccord Genuity Corp., Desjardins Securities Inc., Laurentian Bank Securities Inc., Raymond James Ltd., Industrial Alliance Securities Inc. and Wells Fargo Securities Canada, Ltd. (collectively, the "Underwriters") are underwriters of the Offering. The Underwriters, as principals, conditionally offer the Debentures represented by Instalment Receipts, subject to prior sale, if, as and when issued by the Corporation and sold and delivered by the Selling Debentureholder to, and accepted by, the Underwriters in accordance with the terms and conditions contained in the Underwriting Agreement (as defined in this Prospectus) referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation and the Selling Debentureholder by Osler, Hoskin & Harcourt LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP. Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Instalment Receipts representing the Debentures or the Common Shares at levels above those which may prevail on the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

RBC Dominion Securities Inc., CIBC World Market Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders that have made a $250 million operating credit facility (the "Operating Credit Facility") available to Hydro One Limited. In addition, RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., Desjardins Securities Inc. and Laurentian Bank Securities Inc. are subsidiaries or affiliates of lenders that have made a $2.3 billion unsecured revolving credit facility available to Hydro One Inc., a wholly-owned subsidiary of Hydro One Limited. **Consequently, the Corporation and/or the Selling Debentureholder may be considered a "connected issuer" of these Underwriters within the meaning of applicable securities legislation. See "Relationship between Hydro One Limited, the Selling Debentureholder and Certain Underwriters"**.

Subscriptions for the Debentures represented by Instalment Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the Closing Date will take place on or about August 9, 2017, or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than August 23, 2017. The

Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus relating to the Offering.

A book-entry only certificate representing the Instalment Receipts (representing the Debentures) distributed hereunder will be issued in registered form only to CDS Clearing and Depository Services Inc. ("CDS") or its nominee and will be deposited with CDS on the Closing Date. Subject to compliance with the provisions of the Instalment Receipt Agreement, as soon as practicable on or after the Final Instalment Date provided that payment of the final instalment has been made, the global certificate representing the Instalment Receipts will be cancelled and the global certificate representing the Debentures distributed hereunder, pledged to the Selling Debentureholder and held by Computershare Trust Company of Canada, as security agent, will be discharged and released and one or more new global certificates representing the Debentures will be delivered to CDS and registered in the name of CDS or its nominee (as adjusted for Debentures that have been converted into Common Shares on the Final Instalment Date). The Corporation understands that a purchaser of Debentures represented by Instalment Receipts will receive only a customer confirmation from the registered dealer (who is a participant in CDS) from or through whom the Debentures represented by Instalment Receipts are purchased. Except as otherwise stated herein, neither the holders of Instalment Receipts representing Debentures nor the holders of Debentures on or following the Final Instalment Date will be entitled to receive physical certificates representing their ownership thereof, as applicable. See "Details of the Offering".

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars.

Kathryn Jackson, a director of Hydro One Limited, resides outside of Canada. Ms. Jackson has appointed Hydro One Limited as her agent for service of process. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person who resides outside of Canada, even if the party has appointed an agent for service of process. See "Enforceability of Certain Civil Liabilities".

The registered and head office of the Corporation is located at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Please refer to the "Glossary of Terms" beginning on page 88 of this short form prospectus (the "Prospectus") for a list of defined terms used herein.

This Prospectus, including the documents incorporated herein by reference, contains forward-looking information within the meaning of applicable securities laws which reflects management's current expectations regarding: (i) the future growth, results of operations, performance, business prospects and opportunities of Hydro One; (ii) the timing and completion of the contemplated Merger; (iii) the benefits and the impact of the Merger and the Offering on the financial position of the Corporation; and (iv) the future performance, business prospects and opportunities of Avista Corp. These expectations may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs, expectations and intentions and is based on information currently available to the Corporation's management.

The forward-looking information in this Prospectus, including the documents incorporated herein by reference, includes, but is not limited to, statements regarding: Hydro One's business; Hydro One's transmission and distribution rate applications, and resulting rates and impacts; expected impacts of changes to the electricity industry; Hydro One's maturing debt and standby credit facilities; expectations regarding the Corporation's financing activities; credit ratings; ongoing and planned projects and/or initiatives, including expected results and timing; expected future capital expenditures, the nature and timing of these expenditures, including the Hydro One's plans for sustaining and development capital expenditures for its distribution and transmission systems; expectations regarding allowed ROE; the ability of Hydro One to recover expenditures in future rates; the Ontario Energy Board; future pension contributions, the pension plan and valuations; expectations regarding the ability to negotiate collective agreements consistent with rate orders and to maintain stable outsourcing arrangements; expectations related to work force demographics; expectations regarding taxes; occupational rights; expectations related to load growth; the regional planning process; expectation related to Hydro One's CDM requirements and targets; Hydro One's customer focus and related initiatives; Hydro One's relationships with First Nations and Métis communities; expectations related to the effect of interest rates; environmental matters and Hydro One's expected future environmental expenditures; Hydro One's reputation; cyber and data security; Hydro One's relationship with the Province; future sales of shares of Hydro One Limited; acquisitions, including the Merger and the Corporation's acquisition of Orillia Power; expectations regarding the governance agreement and other agreements with the Province; the intentions of the Province with respect to future sales of Common Shares; and legal proceedings in which Hydro One is currently involved.

The forward-looking information contained herein pertaining to the Merger and the financing thereof and the future performance, business prospects and opportunities of Avista Corp. includes, but is not limited to, statements regarding: strength of credit metrics; the expectation that the Merger will increase Hydro One's consolidated rate base and total customers; the expectation that the Merger will be accretive to Hydro One Limited's earnings per Common Share; the impact of the Merger on the Corporation's total assets, net income, growth, access to equity and debt capital markets, credit profile, economies of scale and ability to deploy capital; opportunities for costs savings and efficiency gains; the stability of the Corporation's net income and overall quality of cash flows; the expectation that Hydro One will benefit from diversification of regulatory jurisdictions; the expectations regarding rate base growth; expectations regarding the economic outlook in Washington and in the U.S. generally; the complementary management teams and corporate cultures of Hydro One and Avista Corp.; Avista Corp's labour relations; expectations regarding the nature, timing and costs of capital spending of Hydro One and Avista Corp.; the locations of the combined operations after completion of the Merger; the expectations with respect to the impact of costs and compliance as a result of new and existing laws, regulations and guidelines, including, but not limited to, environmental matters; the impact of legal proceedings; the financing of the Merger, including, but not limited to, the use of the net proceeds of the Offering, the impact of the Offering, the timing and closing of the Merger, the conversion of the Debentures into Common Shares, the issuance of Common Shares and the impact of changes to Hydro One's long-term debt on the capital structure of Hydro One; the listing of securities on and approval of the TSX; the timing of payment of each of the first instalment and the final instalment payments; the plan of distribution pursuant to the Underwriting Agreement; the risk factors relating to the Merger, the post-Merger combined business and operations of Hydro One and Avista Corp., the Instalment Receipts, the Debentures and the Common Shares; the Corporation's intention to declare and pay dividends and targeted dividend payout ratio; and market stabilization activities by the Underwriters.

The forecasts and projections that make up the forward-looking information included in this Prospectus are based on assumptions which include, but are not limited to: the timing and completion of the Merger; the receipt of Avista Shareholder Approval, the required regulatory approvals relating to the Merger and other conditions precedent to closing the Merger; the payment to the Selling Debentureholder of the aggregate amount of the final instalment; the conversion of all of the Debentures distributed pursuant to this Prospectus into Common Shares on the Final Instalment Date; the realization by Hydro One of the anticipated benefits of the Merger, including the expectation that the Merger will be accretive to Hydro One Limited's earnings per Common Share; the impact of the Merger on Hydro One's total assets, net income, growth, access to equity and debt capital markets, credit profile, economies of scale and ability to deploy capital; that Hydro One and Avista Corp. have complementary management teams and corporate cultures and that this will support a smooth combination of the two companies; the accuracy of the *pro forma* combined financial information, which does not purport to be indicative of the financial information that will result from the operations of Hydro One on a consolidated basis following the closing of the Merger and the completion of the Offering; relatively stable currency exchange rates between Canadian and U.S. dollars; the ability of Hydro One to successfully integrate the business and operations of Avista Corp. into the Hydro One group of companies; opportunities for cost savings and efficiency gains will arise; the ability of Hydro One to retain key personnel of Avista Corp., and the value of such key employees; the ability of Hydro One to satisfy its liabilities and meet its debt service obligations following completion of the Merger; the aggregate amount of the Merger-Related Expenses; the ability to maintain dividend payout ratios; the accuracy and completeness of Avista Corp.'s public and other disclosure reflected in this Prospectus; the absence of undisclosed liabilities of Avista Corp.; no unforeseen changes in the legislative and operating framework for Ontario's electricity market and the electricity and natural gas markets in which Avista Corp. operates; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for any of Hydro One's or Avista Corp.'s rate-regulated businesses; no unfavourable changes in environmental regulation; continued use of U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: inability to complete the Offering; inability to complete the Merger; an increase in the cash purchase price of the Merger; uncertainty regarding the length of time required to complete the Merger; failure to obtain Avista Shareholder Approval; the required shareholder, governmental or regulatory approvals may delay the proposed Merger or impose conditions; the effect and timing of changes in laws or in governmental regulations; disruption from the proposed Merger making it more difficult to maintain relationships with customers, employees, regulators or suppliers; the diversion of management time and attention on the Merger; the financing necessary to fund the Merger may not be obtained or may be more difficult and costly to obtain than anticipated; the ability to maintain an investment grade credit rating; the anticipated benefits of the Merger may not materialize or may not occur within the time periods anticipated by the Corporation; impact of significant demands placed on the Corporation as a result of the Merger; lack of control by the Corporation of Avista Corp. prior to the closing of the Merger; impact of the Merger-Related Expenses or increases in the Merger-Related Expenses; potential that the Corporation Termination Fee may need to be paid in certain circumstances; accuracy and completeness of Avista Corp.'s publicly disclosed information; increased indebtedness of Hydro One after the closing of the Merger; historical and *pro forma* combined financial information may not be representative of future performance; potential undisclosed liabilities of Avista Corp.; inability to retain key personnel of Avista Corp. following the Merger; indebtedness of Avista Corp.; risks relating to the Instalment Receipts, the Debentures and the Common Shares; risks associated with the Province's share ownership of Hydro One Limited and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties; regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures; the risk that Hydro One may be unable to comply with regulatory and legislative requirements or that Hydro One may incur additional costs for compliance that are not recoverable through rates; the risk of exposure of Hydro One's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Hydro One is uninsured or for which Hydro One could be subject to claims for damage; public opposition to and delays or denials of the requisite approvals and accommodations for Hydro One's planned projects; the risk that Hydro One may incur significant costs associated with transferring assets located on reserves; the risks associated with information system security and with maintaining a complex information technology system infrastructure; the risks related to Hydro One's work force demographic and its potential inability to attract and retain qualified personnel; the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with Hydro One's rate decisions; the risk that Hydro One is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures; risks associated with fluctuations in interest rates and failure to manage exposure to credit risk; the risk that Hydro One may not be able to execute plans for capital projects necessary to maintain the performance of Hydro One's assets or to carry out projects in a timely manner; the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications; the risk that assumptions that form the basis of Hydro One's recorded environmental liabilities and related regulatory assets may change; the risk of not being able to recover Hydro One's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs; the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected; the risks associated with economic uncertainty and financial market volatility; the inability to prepare financial statements using U.S. GAAP; and the impact of the ownership by the Province of lands underlying Hydro One's transmission system.

All forward-looking information in this Prospectus and in the documents incorporated herein by reference is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Corporation listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces and territories of Canada are specifically incorporated by reference into and form an integral part of this Prospectus:

(i) Hydro One Limited's annual information form dated March 27, 2017 for the year ended December 31, 2016 (the "**AIF**");

(ii) Hydro One Limited's audited consolidated financial statements as at and for the years ended December 31, 2016 and December 31, 2015, together with the notes thereto and the independent auditors' report thereon dated February 9, 2017 (the "**2016 Annual Financial Statements**");

(iii) Hydro One Limited's management's discussion and analysis in respect of the 2016 Annual Financial Statements (the "**Annual MD&A"**);

(iv) Hydro One Limited's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2017 and 2016, together with the notes thereto (the "**Interim Financial Statements**");

(v) Hydro One Limited's management's discussion and Analysis in respect of the Interim Financial Statements (the "**Interim MD&A**");

(vi) Hydro One Limited's management information circular dated March 23, 2017 prepared in connection with Hydro One Limited's annual meeting of shareholders held on May 4, 2017;

(vii) the template version of the term sheet dated July 19, 2017 and the template version of the investor presentation dated July 19, 2017 (a copy of which is attached as Appendix A to this Prospectus), each filed on SEDAR in connection with the Offering (collectively, the "**Marketing Materials**"); and

(viii) the material change report dated July 20, 2017 announcing the Merger and the Offering.

Any documents of the type referred to above (other than confidential material change reports), any document filed by Hydro One Limited that specifically states that such document is incorporated by reference into this Prospectus and any other documents required under applicable securities laws to be incorporated by reference into this Prospectus, if filed by Hydro One Limited with the provincial securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the termination of the Offering, shall be deemed to be incorporated by reference into this Prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference in this Prospectus shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated herein by reference, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed to be an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of the Corporation at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5, telephone (416) 345-6044, and are also available electronically at www.sedar.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this Prospectus and is not, and should not be considered to be, a part of this Prospectus, unless it is explicitly so incorporated.

MARKETING MATERIALS

The Marketing Materials (including the Investor Presentation) are not part of this Prospectus to the extent that the contents of the Marketing Materials have been modified or superseded by a statement contained elsewhere in this Prospectus. Any template version of "marketing materials" (as defined in National Instrument 41-101 – *General Prospectus Requirements*) filed after the date of this Prospectus and before the termination of the distribution under the Offering (including any amendments to, or an amended version of, the Marketing Materials) are deemed to be incorporated into this Prospectus. The template version of the investor presentation dated July 19, 2017, with the cautionary legend required by Section 7.6(5) of National Instrument 44-101 – Short Form Prospectus Distributions removed (the "**Investor Presentation**"), is attached as Appendix A to this Prospectus.

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to Hydro One Limited and the Selling Debentureholder, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, provided that, on the date hereof, Hydro One Limited is a "public corporation" for the purposes of the Tax Act or the Common Shares are listed on a "designated stock exchange" for the purposes of the Tax Act (which currently includes the TSX), the Debentures represented by Instalment Receipts and the Common Shares issuable on the conversion or maturity of the Debentures, if issued on the date hereof, would be qualified investments under the Tax Act as of the date hereof for a trust governed by an RRSP, a RRIF, an RESP, a DPSP, an RDSP or a TFSA (collectively, "**Exempt Plans**"), except, in the case of the Debentures, a DPSP to which Hydro One Limited, or an employer that does not deal at arm's length with Hydro One Limited, has made a contribution. Holders or annuitants of Exempt Plans should have regard to any restrictions (including restrictions on pledging plan assets) that may be included in the provisions of their particular Exempt Plan.

Notwithstanding the foregoing, if the Debentures or the Common Shares are a "prohibited investment" (as defined in the Tax Act) for a trust governed by a TFSA, RRSP or RRIF, the holder or annuitant thereof, as the case may be, will be subject to a penalty tax as set out in the Tax Act. The Debentures and Common Shares will not be a prohibited investment for a TFSA, RRSP or RRIF provided the holder or annuitant of such Exempt Plan, as the case may be, (i) deals at arm's length with Hydro One Limited, for purposes of the Tax Act and (ii) does not have a "significant interest" (as defined in the prohibited investment rules in the Tax Act) in Hydro One Limited. In addition, Common Shares will not be a "prohibited investment" if the Common Shares are "excluded property" (as defined in the Tax Act for this purpose) for trusts governed by a TFSA, RRSP and RRIF. Based on certain Proposed Amendments (as defined herein) announced on March 22, 2017, it is proposed that the prohibited investment rules described above (including the rules relating to "excluded property") will be extended to cover trusts governed by RDSPs and RESPs.

A holder, annuitant or subscriber, as the case may be, should consult her own tax advisor with respect to whether the Instalment Receipts, Debentures or Common Shares would be a prohibited investment and whether the Instalment Receipts, Debentures or Common Shares otherwise comply with any restrictions that may apply to a particular Exempt Plan (including restrictions on the pledging of plan assets).

PRESENTATION OF FINANCIAL INFORMATION

The financial statements of the Corporation included in this Prospectus are reported in Canadian dollars and have been prepared in accordance with U.S. GAAP. All financial information of Avista Corp. included in this Prospectus (other than *pro forma* financial statements) as at or for the periods ended December 31, 2016 and 2015 is reported in U.S. dollars and has been derived from audited historical financial statements of Avista Corporation that were prepared in accordance with U.S. GAAP. All financial information of Avista Corp. included in this Prospectus (other than *pro forma* financial statements) as at or for the periods ended March 31, 2017 and 2016 is reported in U.S. dollars and has been derived from unaudited historical financial statements of Avista Corporation that were prepared in accordance with U.S. GAAP. The assets and liabilities of Avista Corp. shown in the unaudited *pro forma* consolidated balance sheet of the Corporation as at March 31, 2017 are reported in Canadian dollars and reflect the U.S. dollar-to-Canadian dollar period-end closing exchange rate. The revenues and expenses of Avista Corp. shown in the unaudited *pro forma* consolidated statements of operations of the Corporation for the three month period ended March 31, 2017 and for the year ended December 31, 2016 are reported in Canadian dollars and reflect the average U.S. dollar-to-Canadian dollar exchange rates for such periods. Financial information in this Prospectus that has been derived from the unaudited *pro forma* consolidated financial statements has been translated to Canadian dollars on the same basis. Certain tables in this Prospectus may not add due to rounding.

Certain financial measures of Hydro One and Avista Corp. are used in this Prospectus that do not have standardized meanings under U.S. GAAP and may not be comparable to similar measures presented by other entities. Such non-U.S. GAAP measures are calculated by adjusting certain U.S. GAAP measures for specific items that Hydro One Limited and Avista Corporation believe are significant, but not reflective of the underlying operations of the Corporation.

Funds from Operations and Adjusted FFO

Funds from Operations ("**FFO**") is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to non-controlling interest.

Adjusted FFO is defined as FFO, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the payment in lieu of corporate income taxes ("**PILs**") regime (the "**PILs Regime**") and entering the regular Canadian federal and Ontario income tax regime (the "**Federal Tax Regime**").

Management believes that FFO and Adjusted FFO are helpful as supplemental measures of the Corporation's operating cash flows as they exclude timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders, and, in the case of Adjusted FFO, the impact of the IPO-related deferred income tax asset. As such, these measures provide consistent measures of the cash generating performance of the Corporation's assets.

Adjusted Net Cash from Operating Activities

Adjusted net cash from operating activities is defined as net cash from operating activities, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that this measure is helpful as a supplemental measure of the Corporation's net cash from operating activities as it excludes the impact of the IPO-related deferred income tax asset. As such, adjusted net cash from operating activities provides a consistent measure of the Corporation's cash from operating activities compared to prior periods.

Adjusted Earnings Per Share

The basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which assumes that the total number of Common Shares outstanding was 595,000,000 in each of the periods presented. Adjusted EPS has been used internally by management subsequent to the IPO of the Corporation's Common Shares in November 2015 to assess the Corporation's performance and is considered useful because it eliminates the impact of a different and non-comparable number of shares outstanding and held by the Province prior to the IPO. EPS is considered an important measure and management believes that presenting it consistently for all periods based on the number of outstanding shares on, and subsequent to, the IPO provided users with a comparative basis to evaluate the operations of the Corporation.

Additional information regarding non-U.S. GAAP measures used by Hydro One Limited can be found in the Interim MD&A and the Annual MD&A.

Electric Gross Margin and Natural Gas Gross Margin

The description in the Prospectus relating to Avista Utilities uses electric gross margin and natural gas gross margin, both of which are non-U.S. GAAP financial measures. The presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of operating performance. Avista Utilities uses these measures to determine whether the appropriate amount of revenue is being collected from customers to allow for the recovery of energy resource costs and operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact Avista Utilities' results of operations. In addition, Avista Utilities presents electric and natural gas gross margin separately for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, such that separate analysis is beneficial. These measures are not intended to replace income from operations as determined in accordance with U.S. GAAP as an indicator of operating performance.

CAUTION REGARDING UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

This Prospectus contains the unaudited *pro forma* consolidated balance sheet of the Corporation as at March 31, 2017 and consolidated statements of earnings of the Corporation for the three month period ended March 31, 2017 and for the year ended December 31, 2016, giving effect to: (i) the Offering, assuming no exercise of the Over-Allotment Option; (ii) the issuance of Common Shares upon the conversion of the Debentures (assuming no Make-Whole Payment); (iii) the proposed issuance by Hydro One Limited of U.S. dollar denominated debt to finance the Merger; and (iv) the completion of the Merger. Such unaudited *pro forma* consolidated financial statements have been prepared using certain of the Corporation's and Avista Corporation's respective financial statements as more particularly described in the notes to such unaudited *pro forma* consolidated financial statements. In preparing such unaudited *pro forma* consolidated financial statements, Hydro One Limited has had limited access to the non-public books and records of Avista Corp. and makes no representation or warranty as to the accuracy or completeness of such information provided by Avista Corp., including the financial statements of Avista Corporation that were used to prepare the unaudited *pro forma* consolidated financial statements. Such unaudited *pro forma* consolidated financial statements are not intended to be indicative of the results that would actually have occurred, or the results expected in future periods, had the events reflected therein occurred on the dates indicated. Actual amounts recorded upon the finalization of the purchase price allocation under the Merger may differ from such unaudited *pro forma* consolidated financial statements. At the date of preparation of the *pro forma* financial statements, the fair values of Avista Corp.'s identifiable assets and liabilities to be assumed and the full impact of applying acquisition accounting have not been fully determined. After reflecting the *pro forma* adjustments made in the *pro forma* financial statements, the excess of the purchase price consideration of the adjusted book values of Avista Corp.'s net assets has been presented as goodwill offset by an adjustment to eliminate Avista Corp.'s historical goodwill.

Since the unaudited *pro forma* consolidated financial statements have been developed to retroactively show the effect of a transaction that has or is expected to occur at a later date (even though this was accomplished by following generally accepted practice using assumptions that are considered to be reasonable), there are limitations inherent in the very nature of *pro forma* data. The data contained in the unaudited *pro forma* consolidated financial statements represents only a simulation of the potential impact of the Merger. Undue reliance should not be placed on such unaudited *pro forma* consolidated financial statements. See "Special Note Regarding Forward-Looking Statements" and "Risk Factors".

CURRENCY

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to "dollars", "$" or "Cdn$" are to lawful currency of Canada. References to "U.S. dollars" or "US$" are to lawful currency of the United States of America.

The following table sets forth, for each of the periods indicated, the noon exchange rate, the average noon exchange rate and the high and low noon exchange rates of one U.S. dollar in exchange for Canadian dollars as reported by the Bank of Canada.

	Year ended December 31,			Three months ended March 31,	
	2016	2015	2014	2017	2016
High	1.4589	1.3990	1.1643	1.3505	1.4589
Low	1.2544	1.1728	1.0614	1.3004	1.2962
Average	1.3248	1.2787	1.1045	1.3238	1.3732
Period End	1.3427	1.3840	1.1601	1.3322	1.2971

As of July 31, 2017, the daily average rate of exchange as reported by the Bank of Canada was US$1.00 = Cdn$1.2485.

DEFINED TERMS

For an explanation of certain terms and abbreviations used in, and conversions applicable to, this Prospectus, reference is made to the "Glossary of Terms" beginning on page 88 of this Prospectus.

Unless otherwise indicated by the context, references to "Hydro One" refers to Hydro One Limited and its subsidiaries taken together as a whole. References to "Hydro One Inc." refer only to Hydro One Inc. and references to "Hydro One Limited" or the "Corporation" refer only to Hydro One Limited.

Unless otherwise indicated by the context, "Avista Corp." means Avista Corporation and its subsidiaries. References to individual subsidiaries of Avista Corp. refer to that subsidiary company and its respective subsidiaries and references to "Avista Corporation" refer only to Avista Corporation.

THIRD PARTY SOURCES AND INDUSTRY DATA

This Prospectus contains information from publicly available third party sources as well as industry data prepared by the Corporation's management on the basis of its knowledge of the electricity industry in which Hydro One operates (including management's estimates and assumptions relating to the industry based on that knowledge). Management's knowledge of the electricity industry has been developed through its experience and participation in the industry. Management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness of this data. Third-party sources generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of included information. Although management believes it to be reliable, none of Hydro One Limited, Hydro One Inc., the Selling Debentureholder or the Underwriters have independently verified any of the data from third-party sources referred to in this Prospectus or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

PROSPECTUS SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information and financial data and statements appearing elsewhere in this Prospectus and in the documents incorporated herein by reference.

HYDRO ONE LIMITED

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network with over 30,000 circuit km of high-voltage transmission lines, and an approximately 123,000 circuit km low-voltage distribution network.

Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

Hydro One's transmission business consists of owning, operating and maintaining its transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on the revenues approved by the Ontario Energy Board. This includes Hydro One's 66% interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. Hydro One's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. Hydro One's transmission business accounted for approximately 51% of the Corporation's total assets as at December 31, 2016, and approximately 51% of its total revenues, net of purchased power, in 2016. All of Hydro One's transmission business is carried out by its wholly-owned subsidiary Hydro One Inc., through its wholly-owned subsidiary Hydro One Networks Inc. and through other wholly-owned subsidiaries of Hydro One Inc. that own and control Hydro One Sault Ste. Marie LP, as well as the portion of Hydro One's transmission business held through B2M Limited Partnership, which Hydro One controls.

Hydro One's distribution business consists of owning, operating and maintaining its distribution system, which Hydro One, through Hydro One Inc., owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. Hydro One's distribution system is also the largest in Ontario, and principally serves rural communities. Hydro One's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are subject to approval by the Ontario Energy Board. Hydro One's distribution business accounted for approximately 37% of its total assets as at December 31, 2016 and approximately 47% of its total revenues, net of purchased power, in 2016.

Hydro One's other business segment consists principally of Hydro One's telecommunications business, as well as certain corporate activities. The telecommunications business provides telecommunications support for Hydro One's transmission and distribution businesses. The telecommunications business also offers communications and IT solutions to organizations with broadband network requirements. Hydro One's other business segment is not rate-regulated. The other business segment, which in addition to the telecommunications business also includes a deferred tax asset, accounted for approximately 12% of Hydro One's total assets as at December 31, 2016 and approximately 2% of its total revenues, net of purchased power, in 2016.

THE MERGER

Merger Overview

On July 19, 2017, Hydro One Limited, US Parent and Merger Sub entered into the Merger Agreement with Avista Corporation which provides for, among other things, the direct or indirect acquisition by US Parent of Avista Corporation. The aggregate purchase price for the Merger is approximately US$5.3 billion, comprised of an equity purchase price of US$3.4 billion and the assumption of approximately US$1.9 billion of debt. The Merger is subject to receipt of Avista Shareholder Approval and certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the HSR Act, clearance of the Merger by CFIUS, the approval by each of IPUC, MPSC, OPUC, RCA, WUTC, FERC and the FCC, and the satisfaction of other customary closing conditions. The closing of the Merger is currently expected to occur in the second half of 2018.

Based on *pro forma* financial information as at March 31, 2017, following the Merger, Hydro One's total assets will increase from approximately $25.4 billion to approximately $34.9 billion.

Following completion of the Merger, Avista Corporation will maintain its existing corporate headquarters in Spokane and will continue to operate as a standalone utility in Washington, Oregon, Idaho, Montana and Alaska. Its management team will remain in place and it will operate with a board of directors that includes directors representing the interests of the Pacific Northwest and the communities it serves.

Avista Corp. Overview

Avista Corporation, incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2016, Avista Corp. employed 1,742 people in its Pacific Northwest utility operations (Avista Utilities) and 240 people in its subsidiary businesses (including in its Juneau, Alaska utility operations). Avista Corporation's corporate headquarters are in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through its subsidiary AEL&P, Avista Corporation also provides electric utility services in Juneau, Alaska. Avista Corporation is an operating public utility with its common stock listed on the NYSE under the ticker symbol "AVA".

As of March 31, 2017, Avista Corporation had two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corporation (not a subsidiary) that comprises its regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and natural gas customers in eastern Washington and northern Idaho and natural gas customers in parts of Oregon. It also supplies electricity to a small number of customers in Montana, most of whom are its employees who operate its Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation. As of March 31, 2017, Avista Utilities supplied retail electric service to approximately 379,000 customers and retail natural gas service to approximately 342,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.6 million.

- **AEL&P** - a utility providing electric services in Juneau, Alaska that is a wholly-owned subsidiary and the primary operating subsidiary of AERC. Avista Corporation acquired AERC on July 1, 2014, and as of that date, AERC became a wholly-owned subsidiary of Avista Corporation. As of March 31, 2017, AEL&P served approximately 17,000 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

Avista Corporation has other businesses, including sheet metal fabrication, venture fund investments, real estate investments, a company that explores markets that could be served with LNG, as well as certain other investments of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corporation. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corporation, including AM&D, doing business as METALfx.

Merger Highlights

Scale Reinforces Competitive Positioning and Improved Financial Flexibility

As a result of the Merger, Hydro One's enterprise value will increase by over 25% (on a *pro forma* basis), making the combined entity one of North America's largest regulated utilities and a leader in regulated transmission as well as electricity and natural gas local distribution businesses. Post-Merger, on a *pro forma* basis as at March 31, 2017, Hydro One Limited's total assets would increase from approximately $25.4 billion to approximately $34.9 billion and Hydro One Limited's net income for the twelve months ended December 31, 2016 would increase from approximately $746 million to approximately $836 million. Management believes that the Merger will enhance

Hydro One's competitive positioning and provide Hydro One with opportunities for cost savings and non-headcount efficiency gains through enhanced innovation, shared IT systems and increased supply chain purchasing power.

Diversification of Business Segments into Growing Natural Gas Local Distribution Companies and Regulated Primarily Clean Power Generation

The Merger represents entry into complementary and synergistic regulatory assets and adds diversification for Hydro One across multiple geographies, economies, regulators and businesses. Management believes that Avista Corp.'s assets provide an opportunity to expand and diversify Hydro One's footprint to new regulatory jurisdictions (Washington, Idaho, Oregon, Montana and Alaska) with higher ROEs, favourable capital structures and growing economies, all of which will enhance Hydro One's stability and strategic positioning. Following the Merger, Hydro One's operations will have *pro forma* total assets of approximately $34.9 billion (calculated as of March 31, 2017), operate regulated utilities across the Province of Ontario and five U.S. states and serve more than 2 million retail and industrial customers.

Accretive to Earnings

Management expects the Merger will be accretive to Hydro One's earnings per Common Share in the first full year following closing of the Merger. The Merger is expected to provide additional support to Hydro One's growing dividend, and its 70 per cent to 80 per cent targeted dividend payout ratio is expected to remain unchanged upon completion of the Merger.

Experienced Management Teams and Shared Cultures and Values

Hydro One's management believes that Hydro One and Avista Corp. have experienced management teams who share a common heritage with over 230 years of collective operational experience rooted in similar cultures and values. Both Hydro One and Avista Corp. take very seriously their responsibility to be good corporate citizens and community partners and share a common interest in preserving and increasing the philanthropy and economic development in the communities they serve. Additionally, both Hydro One and Avista Corp. share a strong commitment to safety, respect for the environment and the importance of engaging stakeholders in operations. Hydro One's management believes that this cultural fit will allow for a low risk transition and an increased ability to quickly find and implement areas of mutual benefit for the combined entity that do not compromise either company's values. Moreover, Hydro One believes it will benefit from Avista Corp's management team which consists of well-respected industry leaders who have consistently delivered shareholder value.

Innovation and Knowledge Transfer

Avista Corp. is a proven utility sector innovation leader, with a strong track record of progressive investments in sophisticated technologies and energy management solutions that address customers' increasing expectations. See page A-17 of the Investor Presentation attached as Appendix A to this Prospectus. Hydro One's management believes that sharing best practices in innovation and research and development will increase the ability for both Hydro One and Avista Corp. to effectively accelerate the deployment of new technology, to the benefit of the electricity system and its customers.

FINANCING THE MERGER

The cash purchase price of the Merger and the Merger-Related Expenses will be financed at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the existing $250 million operating credit facility of Hydro One Limited (the "**Operating Credit Facility**"); and (iv) existing cash on hand and other sources available to the Corporation.

Prior to the closing of the Merger, Hydro One Limited intends to use the net proceeds of the first instalment under the Offering, which are expected to be $441,700,000 (assuming no exercise of the Over-Allotment Option), to repay borrowings under the Operating Credit Facility or its subsidiaries' existing revolving credit facilities or other existing indebtedness (such indebtedness having been incurred for general corporate purposes), or for other general corporate purposes, including investing in short-term interest bearing U.S. dollar securities with investment grade counterparties and in Hydro One Limited's wholly-owned subsidiaries. In the event that the net proceeds of the first instalment under the Offering are used to reduce outstanding indebtedness, or for other general corporate purposes, Hydro One Limited will maintain readily available capacity on its revolving credit facilities (on a consolidated basis), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment under the Offering. Upon the closing of the Merger, Hydro One Limited intends to use the net proceeds of the final instalment under the Offering, which are expected to be $909,300,000 (assuming no exercise of the Over-Allotment Option), to finance, directly or indirectly, together with the net proceeds of the first instalment under the Offering to the extent available, part of the purchase price payable for the Merger and for other Merger-Related Expenses.

Hydro One Limited currently intends to fund the remainder of the purchase price for the Merger with a combination of bond or other debt financings, denominated principally in U.S. dollars in order to provide a significant natural currency hedge, drawdowns on the Operating Credit Facility and cash on hand.

Hydro One Limited's overall financing plan in respect of the Merger is structured and targeted to maintain Hydro One Limited's and Avista Corporation's strong investment grade status.

See "Risk Factors" for a discussion of certain risks relating to the financing of the Merger.

THE OFFERING

Issuer:	Hydro One Limited
Selling Debentureholder:	2587264 Ontario Inc., a direct wholly-owned subsidiary of Hydro One Limited. See “Details of the Offering – The Selling Debentureholder”.
Offering:	4.00% convertible unsecured subordinated debentures, due September 30, 2027, represented by Instalment Receipts and convertible into Common Shares at a Conversion Price of $21.40 per Common Share.
Amount:	$1,400,000,000 ($1,540,000,000 if the Over-Allotment Option is exercised in full) payable on an instalment basis.
Price:	$1,000 per Debenture represented by an Instalment Receipt, of which the first instalment of $333 is payable on the Closing Date and the final instalment of $667 is payable on or before the Final Instalment Date.
Closing Date:	On or about August 9, 2017, or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than August 23, 2017.
Over-Allotment Option:	The Underwriters shall have the option, exercisable in whole or in part at any time on or prior to the 30th day following the Closing Date to purchase additional Debentures represented by Instalment Receipts equal to up to 10% of the aggregate principal amount of Debentures represented by Instalment Receipts issued at the Closing Date to cover over-allotments, if any, and for market stabilization purposes. See “Plan of Distribution”.
Use of Proceeds:	The net proceeds from the Offering (including both the first instalment and final instalment) will be, in the aggregate, $1,349,500,000 determined after deducting the Underwriters’ fee and the estimated expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds will be, in the aggregate, $1,484,600,000. Prior to the closing of the Merger, Hydro One Limited intends to use the net proceeds of the first instalment under the Offering, which are expected to be $441,700,000 (assuming no exercise of the Over-Allotment Option), to repay borrowings under the Operating Credit Facility or its subsidiaries’ existing revolving credit facilities or other existing indebtedness (such indebtedness having been incurred for general corporate purposes), or for other general corporate purposes, including investing in short-term interest bearing U.S. dollar securities with investment grade counterparties and in Hydro One Limited’s wholly-owned subsidiaries. In the event that the net proceeds of the first instalment under the Offering are used to reduce outstanding indebtedness or for other general corporate purposes, Hydro One Limited will maintain readily available capacity on its revolving credit facilities (on a consolidated basis), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment under the Offering. Upon the closing of the Merger, Hydro One Limited intends to use the net proceeds of the final instalment under the Offering, which are expected to be $909,300,000 (assuming no exercise of the Over-Allotment Option), to finance, directly or indirectly, together with the net proceeds of the first instalment under the Offering to the extent available, part of the purchase price payable for the Merger and for other Merger-Related Expenses. See “Use of Proceeds”.

Listing: Conditional approval of the TSX has been received to list the Instalment Receipts (representing the Debentures) and the Common Shares to be issued upon conversion or maturity of the Debentures on the TSX. **The Debentures will not be listed.** The Common Shares are currently listed on the TSX under the symbol "H", and, once listed, the Instalment Receipts will trade on the TSX under the symbol "H.IR".

Interest: Annual rate of 4.00% per $1,000 principal amount of Debentures will be payable quarterly in arrears in equal instalments (other than the first interest payment and, depending on the Final Instalment Date, the final interest payment) on the last day of December, March, June and September of each year (or the prior business day if the last day falls on a weekend or holiday) to and including the Final Instalment Date. The first interest payment in the amount of $15.78082 per $1,000 principal amount of Debentures will be made on December 29, 2017 and will include interest payable from and including the Closing Date. Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures.

Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective yield per annum to and including the Final Instalment Date is 12.00%.

If the Final Instalment Date is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date (which is referred to in this Prospectus as the "**Make-Whole Payment**"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date.

No interest shall accrue on the Debentures following the Final Instalment Date.

See "Details of the Offering – Debentures".

Conversion: At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date.

The Conversion Price will be $21.40 per Common Share, being a conversion rate of 46.7290 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment no later than the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. No fractional Common Shares will be issued on any conversion, but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the fractional interest multiplied by the Conversion Price provided, however, the Corporation shall not be required to make any payment of less than $10.00.

See "Details of the Offering – Debentures – Conversion Right".

Instalment Payment Arrangements:	The price of $1,000 per $1,000 principal amount of Debentures is payable on an instalment basis. Prior to full payment, beneficial ownership of the Debentures will be represented by Instalment Receipts. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable by the holders of Instalment Receipts on or before the Final Instalment Date. The Final Instalment Notice will set the Final Instalment Date, which shall not be less than 15 days nor more than 90 days following the date of such notice. The Final Instalment Notice shall not be provided to holders until the Approval Conditions have been satisfied. The Final Instalment Date may occur up to 90 days following April 30, 2019. See "Details of the Offering". Each Debenture represented by an Instalment Receipt will be pledged to the Selling Debentureholder to secure the obligation of the holder of the Instalment Receipt to pay the final instalment in respect of such Debenture. **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debentures evidenced by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement governing the Instalment Receipts, be forfeited to the Selling Debentureholder in full satisfaction of the holder's obligations or such Debentures may be sold and the holder of the Instalment Receipt shall remain liable for any deficiency if the proceeds of such sale are insufficient to cover the amount of the final instalment and the costs of such sale (such costs of sale not to exceed $25 per Debenture). See "Details of the Offering – Instalment Receipts".**
Rights of Instalment Receipt Holders:	Holders of Instalment Receipts will be entitled, in the manner set forth in the Instalment Receipt Agreement described herein, to fully receive payments of accrued interest and to exercise the rights of ownership attached to the Debentures represented by such Instalment Receipts unless they fail to pay the final instalment on or before the Final Instalment Date. See "Details of the Offering – Instalment Receipts – Rights and Privileges".

Redemption: Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest (without any Make-Whole Payment) following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Merger Agreement in accordance with its terms; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders of Instalment Receipts on or before April 30, 2019. Upon any such redemption, the Corporation will pay for each Debenture: (i) \$333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) \$667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment.

Until such time as the Debentures have been redeemed or the Final Instalment Date has occurred, the Corporation will at all times hold short-term interest bearing U.S. dollar securities with investment grade counterparties, maintain readily available capacity under the Operating Credit Facility or the revolving credit facilities of its subsidiaries, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering and the exercise of the Over-Allotment Option, if applicable.

In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

See “Details of the Offering – Debentures – Redemption”.

Maturity Date: September 30, 2027.

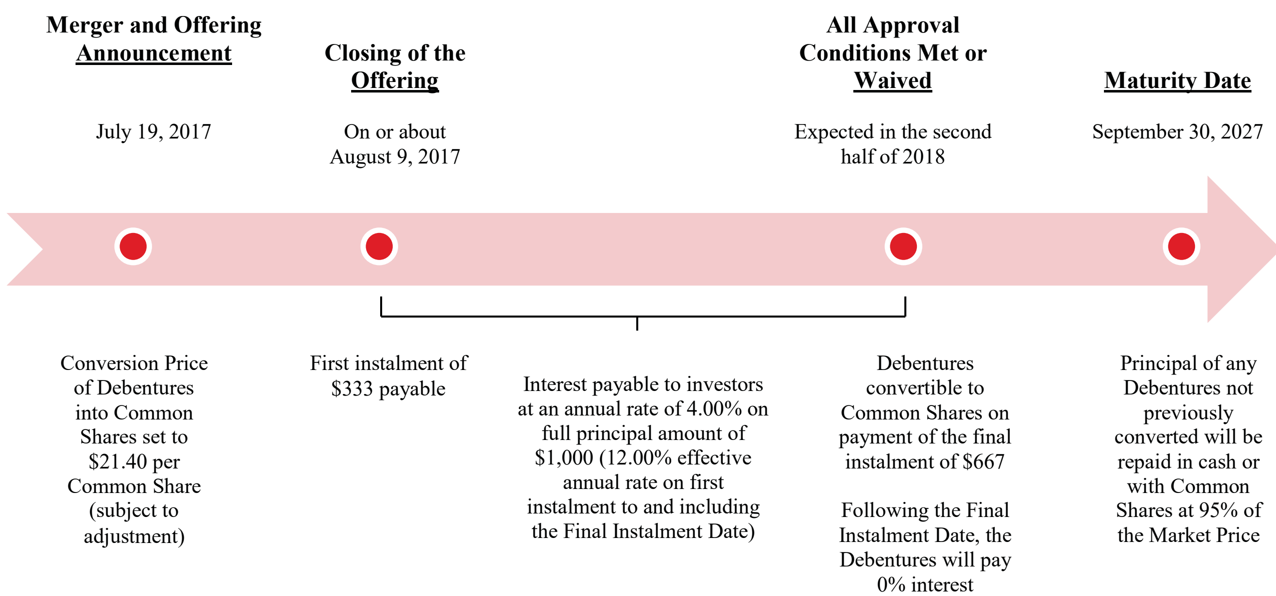
Payment upon Maturity: On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash, provided that the Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the Market Price. See “Details of the Offering – Debentures – Payment Upon Maturity”.

Subordination: The Debentures will be direct unsecured obligations of Hydro One Limited. Payment of the principal of, interest on, any Make-Whole Payments and other amounts owing in respect of each Debenture will (i) be subordinated in right of payment to all present and future Senior Indebtedness of Hydro One Limited and (ii) rank pari passu with each other Debenture of the same series (regardless of their actual date or terms of issue) and, subject to statutory preferred exceptions, with all other present and future subordinated and unsecured indebtedness of Hydro One Limited. The trust indenture pursuant to which the Debentures will be issued does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures, or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. See “Details of the Offering – Debentures – Subordination”.

Ownership Restriction: The *Electricity Act, 1998* (Ontario) precludes any person or company (or combination of persons or companies acting jointly or in concert), other than the Province, from beneficially owning, or exercising control or direction over, more than 10% of the Common Shares. **A potential purchaser of Debentures represented by Instalment Receipts should not subscribe for a number of such Debentures in this Offering that would, upon conversion of such Debentures into Common Shares, cause such purchaser to violate this prohibition.**

Risk Factors: An investment in the Debentures represented by Instalment Receipts and the Common Shares issuable upon conversion thereof involves certain risks which should be carefully considered by prospective investors, including risks in respect of the Merger, the Instalment Receipts, the Debentures, the Common Shares and the post-Merger business and operations of Hydro One and Avista Corp. See “Risk Factors”.

SUMMARY OF IMPORTANT DATES



HYDRO ONE LIMITED

Overview

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Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

Hydro One's transmission business consists of owning, operating and maintaining its transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on the revenues approved by the Ontario Energy Board. This includes Hydro One's 66% interest in B2M Limited Partnership, a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. Hydro One's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. Hydro One's transmission business accounted for approximately 51% of the Corporation's total assets as at December 31, 2016, and approximately 51% of its total revenues, net of purchased power, in 2016. All of Hydro One's transmission business is carried out by its wholly-owned subsidiary Hydro One Inc., through its wholly-owned subsidiary Hydro One Networks Inc. and through other wholly-owned subsidiaries of Hydro One Inc. that own and control Hydro One Sault Ste. Marie LP, as well as the portion of Hydro One's transmission business held through B2M Limited Partnership, which Hydro One controls.

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Hydro One Limited was incorporated on August 31, 2015 under the OBCA. On October 31, 2015, Hydro One Limited acquired all of the issued and outstanding shares of Hydro One Inc. from the Province in exchange for the issuance of Common Shares and Series 1 Preferred Shares to the Province.

The address of the head and registered office of Hydro One is 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

See the section entitled "Business of Hydro One" in the AIF for further details relating to the Corporation's business.

RECENT DEVELOPMENTS

Credit Rating Reviews

Hydro One

On July 19, 2017, S&P revised its outlook on Hydro One Limited and Hydro One Inc. to negative from stable while affirming the existing ratings, including its 'A' long-term corporate credit rating on both Hydro One

Limited and Hydro One Inc. S&P indicated that the negative outlook on Hydro One Limited reflects its view that the Merger signals a shift in Hydro One Limited's business strategy, which will align the company with its global peers removing the historical rationale for a one-notch rating uplift, and the execution and financing risk inherent in any large acquisition.

On July 19, 2017, DBRS issued a press release commenting on the Merger. DBRS' comments reflect DBRS' view that should the Merger be financed as contemplated in the announcement, it will have no impact on Hydro One Inc.'s credit profile.

On July 19, 2017, Moody's affirmed the ratings of Hydro One Inc.'s (i) senior unsecured regular bonds (A3); (ii) senior unsecured medium-term note program ((P)A3); and (iii) senior unsecured commercial paper (P-2), and changed the outlook to negative from stable. Moody's indicated that the negative outlook on Hydro One Inc. reflects its view that the Merger will reduce the probability of extraordinary support from the Province.

Avista Corporation

On July 19, 2017, S&P affirmed its ratings, including the 'BBB' issuer credit rating, on Avista Corporation and revised the outlook to positive from stable. The positive outlook reflects S&P's view of the potential for higher ratings on Avista Corporation if the Merger is completed as proposed based on its view that Avista Corporation will be an important member of the Hydro One group, highly unlikely to be sold and integral to overall group strategy and operations.

On July 19, 2017, Moody's affirmed the ratings of Avista Corporation's (i) issuer rating (Baa1); (ii) multiple seniority medium-term note program ((P)A2); (iii) senior secured medium-term notes (A2); (iv) senior secured first mortgage bonds (A2); (v) senior secured medium-term note program ((P)A2); and (vi) senior unsecured medium-term note program ((P)Baa1) and kept the outlook at stable. Moody's indicated that the stable rating outlook on Avista Corporation reflects its view that the Merger will not materially affect the credit quality of Avista Corporation.

Outlook

Milder weather in the first half of 2017 and a lower approved ROE for both Hydro One's transmission and distribution businesses have negatively impacted results of operations relative to the same period in 2016. A delay in approval of Hydro One's 2017-2018 transmission rates filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of decision at that time.

Chief Financial Officer Accepted New Role

On May 19, 2017, Michael Vels, former Chief Financial Officer of Hydro One, left Hydro One to assume the position of Executive Vice President and Chief Financial Officer of Empire Company Limited and its wholly-owned subsidiary Sobeys Inc.

THE MERGER

Merger Overview

On July 19, 2017, Hydro One Limited, US Parent and Merger Sub entered into the Merger Agreement with Avista Corporation which provides for, among other things, the direct or indirect acquisition by US Parent of Avista Corporation. The aggregate purchase price for the Merger is approximately US$5.3 billion, comprised of an equity purchase price of US$3.4 billion and the assumption of approximately US$1.9 billion of debt. The Merger is subject to receipt of Avista Shareholder Approval and certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the HSR Act, clearance of the Merger by CFIUS, the approval by each of IPUC, MPSC, OPUC, RCA, WUTC, FERC and the FCC, and the satisfaction of other customary closing conditions. The closing of the Merger is currently expected to occur in the second half of 2018.

Based on *pro forma* financial information as at March 31, 2017, following the Merger, Hydro One's total assets will increase from approximately $25.4 billion to approximately $34.9 billion.

Following completion of the Merger, Avista Corporation will maintain its existing corporate headquarters in Spokane and will continue to operate as a standalone utility in Washington, Oregon, Idaho, Montana and Alaska. Its management team will remain in place and it will operate with a board of directors that includes directors representing the interests of the Pacific Northwest and the communities it serves.

Merger Highlights

Scale Reinforces Competitive Positioning and Improved Financial Flexibility

As a result of the Merger, Hydro One's enterprise value will increase by over 25% on a *pro forma* basis, making the combined entity one of North America's largest regulated utilities and a leader in regulated transmission as well as electricity and natural gas local distribution businesses. Post-Merger, on a *pro forma* basis as at March 31, 2017, Hydro One Limited's total assets would increase from approximately $25.4 billion to approximately $34.9 billion and Hydro One Limited's net income for the twelve months ended December 31, 2016 would increase from approximately $746 million to approximately $836 million. Management believes that the Merger will enhance Hydro One's competitive positioning and provide Hydro One with opportunities for cost savings and non-headcount efficiency gains through enhanced innovation, shared IT systems and increased supply chain purchasing power.

Diversification of Business Segments into Growing Natural Gas Local Distribution Companies and Regulated Primarily Clean Power Generation

The Merger represents entry into complementary and synergistic regulatory assets and adds diversification for Hydro One across multiple geographies, economies, regulators and businesses. Management believes that Avista Corp.'s assets provide an opportunity to expand and diversify Hydro One's footprint to new regulatory jurisdictions (Washington, Idaho, Oregon, Montana and Alaska) with higher ROEs, favourable capital structures and growing economies, all of which will enhance Hydro One's stability and strategic positioning. Following the Merger, Hydro One's operations will have *pro forma* total assets of approximately $34.9 billion (calculated as of March 31, 2017), operate regulated utilities across the Province of Ontario and five U.S. states and serve more than 2 million retail and industrial customers.

Accretive to Earnings

Management expects the Merger will be accretive to Hydro One's earnings per Common Share in the first full year following closing of the Merger. The Merger is expected to provide additional support to Hydro One's growing dividend, and its 70 per cent to 80 per cent targeted dividend payout ratio is expected to remain unchanged upon completion of the Merger.

Experienced Management Teams and Shared Cultures and Values

Hydro One's management believes that Hydro One and Avista Corp. have experienced management teams who share a common heritage with over 230 years of collective operational experience rooted in similar cultures and values. Both Hydro One and Avista Corp. take very seriously their responsibility to be good corporate citizens and community partners and share a common interest in preserving and increasing the philanthropy and economic development in the communities they serve. Additionally, both Hydro One and Avista Corp. share a strong commitment to safety, respect for the environment and the importance of engaging stakeholders in operations. Hydro One's management believes that this cultural fit will allow for a low risk transition and an increased ability to quickly find and implement areas of mutual benefit for the combined entity that do not compromise either company's values. Moreover, Hydro One believes it will benefit from Avista Corp's management team which consists of well-respected industry leaders who have consistently delivered shareholder value.

Innovation and Knowledge Transfer

Avista Corp. is a proven utility sector innovation leader, with a strong track record of progressive investments in sophisticated technologies and energy management solutions that address customers' increasing expectations. See page A-17 of the Investor Presentation attached as Appendix A to this Prospectus. Hydro One's management believes that sharing best practices in innovation and research and development will increase the ability for both Hydro One and Avista Corp. to effectively accelerate the deployment of new technology, to the benefit of the electricity system and its customers.

For additional information on the Merger, its expected benefits, its expected timing to completion and its strategic rationale, see pages A-6, A-7, A-11 and A-13 to A-19 of the Investor Presentation attached as Appendix A to this Prospectus.

THE ACQUIRED BUSINESS

Avista Corp.

Avista Corporation, incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2016, Avista Corp. employed 1,742 people in its Pacific Northwest utility operations (Avista Utilities) and 240 people in its subsidiary businesses (including in its Juneau, Alaska utility operations). Avista Corporation's corporate headquarters are in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through its subsidiary AEL&P, Avista Corporation also provides electric utility services in Juneau, Alaska. Avista Corporation is an operating public utility with its common stock listed on the NYSE under the ticker symbol "AVA".

As of March 31, 2017, Avista Corporation had two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corporation (not a subsidiary) that comprises its regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and natural gas customers in eastern Washington and northern Idaho and natural gas customers in parts of Oregon. It also supplies electricity to a small number of customers in Montana, most of whom are its employees who operate its Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation.

- **AEL&P** - a utility providing electric services in Juneau, Alaska that is a wholly-owned subsidiary and the primary operating subsidiary of AERC. Avista Corporation acquired AERC on July 1, 2014, and as of that date, AERC became a wholly-owned subsidiary of Avista Corporation.

Avista Corporation has other businesses, including sheet metal fabrication, venture fund investments, real estate investments, a company that explores markets that could be served with LNG, as well as certain other investments of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corporation. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corporation, including AM&D, doing business as METALfx.

Avista Utilities

As of March 31, 2017, Avista Utilities supplied retail electric service to approximately 379,000 customers and retail natural gas service to approximately 342,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.6 million.

Electric Resources

Hydroelectric Resources

Avista Utilities owns and operates six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is typically Avista Utilities lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, Avista Utilities estimates that it would be able to meet approximately one-half of its total average electric requirements (both retail and long-term wholesale) with the combination of its hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Avista Utilities estimate of normal annual hydroelectric generation for 2017 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 538 average MW (or 4.7 million MWhs).

Thermal Resources

Avista Utilities owns the following thermal generating resources:

- the combined cycle CT natural gas-fired Coyote Springs 2 located near Boardman, Oregon, a 15 percent interest in a twin-unit, coal-fired boiler generating facility, Colstrip 3 & 4, located in southeastern Montana,

- a wood waste-fired boiler generating facility known as the Kettle Falls Generating Station ("**Kettle Falls GS**") in northeastern Washington,

- a two-unit natural gas-fired CT generating facility, located in northeastern Spokane ("**Northeast CT**"),

- a two-unit natural gas-fired CT generating facility in northern Idaho ("**Rathdrum CT**"), and

- two small natural gas-fired generating facilities ("**Boulder Park GS**" and "**Kettle Falls CT**").

Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under a combination of term contracts and spot market purchases, including transportation agreements with bilateral renewal rights.

Colstrip, which is operated by Talen Energy LLC, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019. During 2016, Talen Energy LLC provided notice to the Colstrip owners that it no longer plans to operate units 3 & 4 after May 2018. The Colstrip owners are searching for a replacement operator for units 3 & 4.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS.

The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. Avista Utilities also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

Avista Utilities has the exclusive rights to all the capacity of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to Avista Utilities through 2026 under a PPA. Under the terms of the PPA, Avista Utilities makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant; as such, Avista Utilities considers this plant to be part of its baseload resources.

Wind Resources

Avista Utilities has the exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. Avista Utilities has a PPA that expires in 2042 and allows it to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of 105 MW. Generation from Palouse Wind was 349,771 MWhs in 2016, 293,563 MWhs in 2015 and 335,291 MWhs in 2014. Avista Utilities has an annual option to purchase the wind project beginning in December 2022. The purchase price per the PPA is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20-year term of the agreement. Under the terms of the PPA, Avista Utilities does not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Other Purchases, Exchanges and Sales

In addition to the resources described above, Avista Utilities purchases and sells power under various long-term contracts, and also enters into short-term purchases and sales. Further, pursuant to PURPA, as amended, Avista Utilities is required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC.

Hydroelectric Licenses

Avista Corp. is a licensee under the FPA as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding Little Falls, its other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over by the federal government of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case, plus severance damages. In the unlikely event that a take-over occurs, it could lead to either the decommissioning of the hydroelectric project or offering the project to another party (likely through sale and transfer of the license).

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in March 2001.

Five of Avista Corp.'s six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license issued in June 2009 and are referred to collectively as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC.

Natural Gas Operations

Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon.

Natural Gas Supply

Avista Utilities purchases all of its natural gas in wholesale markets. Avista Utilities is connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different pipeline networks. Access to this diverse portfolio of natural gas resources allows it to make natural gas procurement decisions that benefit its natural gas customers. These interstate pipeline transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources and 75 percent from Canadian sourced supply. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause Avista Utilities resource mix to vary.

Natural Gas Storage

Avista Utilities owns a one-third interest in Jackson Prairie. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. As an owner, Avista Utilities' share is one-third of the peak day deliverability and total working capacity. Avista Utilities also contracts for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

Avista Utilities optimizes its natural gas storage capacity throughout the year by executing transactions that capture favourable market price spreads. Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn at a later time. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market.

Alaska Electric Light and Power Company

AEL&P is the primary operating subsidiary of AERC. AEL&P is the sole utility providing electrical energy in Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneau's economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska.

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity as of December 31, 2016. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the output of the Snettisham hydroelectric project (totaling 78.2 MW of capacity).

The Snettisham hydroelectric project is owned by the AIDEA, a public corporation of the State of Alaska. AEL&P has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation expiring in December 2038, to purchase all of the output of the project.

For accounting purposes, this PPA is treated as a capital lease and as of March 31, 2017 and December 31, 2016, the capital lease obligation was US$61.6 million and US$62.2 million, respectively. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time.

As of December 31, 2016, AEL&P also had 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary.

As of March 31, 2017, AEL&P served approximately 17,000 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P's customers require approval by the RCA pursuant to RCA regulations. AEL&P filed an electric general rate case during 2016.

AEL&P is also subject to the jurisdiction of the FERC concerning the permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2018, but AEL&P plans to extend this license. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corporation subsidiary.

The Snettisham hydroelectric project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. In addition, AEL&P is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws.

Other Businesses

As of March 31, 2017, Avista Corporation's other businesses had assets of approximately US$58.4 million (excluding intracompany amounts) compared to assets of US$55.3 million as of December 31, 2016. Avista Corporation's other businesses are described below.

Avista Capital

- Salix is a wholly-owned subsidiary of Avista Capital that explores markets that could be served with LNG.

- Equity investments are primarily in an emerging technology venture capital fund.

Avista Development

- Equity investments are primarily in emerging technology venture capital funds and companies, including an investment in a technology company that delivers scalable smart grid solutions to global partners and customers, and a predictive data science company.

- Real estate consists primarily of mixed use commercial and retail office space.

- Notes receivable and other assets are primarily long-term notes receivable made to a company focused on spurring economic development throughout the State of Washington.

- AM&D doing business as METALfx performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, construction, telecom, renewable energy and medical industries. The asset balance above excludes an intercompany loan from METALfx to Avista Corporation. The loan balance was US$4.3 million as of March 31, 2017 and US$4.0 million as of December 31, 2016.

Alaska companies

- Includes AERC and AJT Mining, which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties.

Over time as opportunities arise, Avista Corp. disposes of investments and phases out operations that do not fit with its overall corporate strategy. However, Avista Corp. may invest incremental funds to protect its existing investments and invest in new businesses that it believes fit in with its overall corporate strategy.

Results of Operations

Avista Corporation

The following table presents net income (loss) attributable to Avista Corporation for each of its business segments (and the other businesses) for the three months ended March 31, 2017 and years ended December 31, 2016 and December 31, 2015 (U.S. dollars in thousands):

Period	**Three Months ended March 31, 2017**	**Year ended December 31, 2016**	**Year ended December 31, 2015**
Avista Utilities	$58,439	$132,490	$113,360
AEL&P	$ 3,853	$7,968	$6,641
Ecova – Discontinued operations			$5,147
Other	$(176)	$(3,230)	$(1,921)
Net income	$62,116	$137,228	$123,227

Avista Utilities

Three months ended March 31, 2017 compared to the three months ended March 31, 2016

The following table presents Avista Utilities' operating revenues, resource costs and resulting gross margin for the three months ended March 31, 2017 and three months ended March 31, 2016 (U.S. dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	$ 263,718	$ 262,802	$ 170,212	$ 155,410	$ (18,549)	$ (18,065)	$ 415,381	$ 400,147
Resource costs	90,875	94,351	90,287	82,792	(18,549)	(18,065)	162,613	159,078
Gross margin	$ 172,843	$ 168,451	$ 79,925	$ 72,618	$ -	$ -	$ 252,768	$ 241,069

Year end 2016 compared to year end 2015

The following table presents Avista Utilities' operating revenues, resource costs and resulting gross margin for the years ended December 31, 2016 and December 31, 2015 (U.S. dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2016	2015	2016	2015	2016	2015	2016	2015
Operating revenues	$ 996,959	$ 997,873	$ 470,894	$ 521,010	$ (95,215)	$ (107,020)	$1,372,638	$1,411,863
Resource costs	360,591	400,910	273,976	351,101	(95,215)	(107,020)	539,352	644,991
Gross margin	$ 636,368	$ 596,963	$ 196,918	$ 169,909	$ -	$ -	$ 833,286	$ 766,872

Avista Utilities Electric Operations Statistics

The following table presents Avista Utilities' operating revenues and energy sales for its electric operations for the three months ended March 31, 2017 and the years ended December 31, 2016 and December 31, 2015 (U.S. dollars in thousands):

Avista Utilites Electric Operating Statistics

	Operating Revenues (thousand US$)			***Energy Sales (thousands of MWhs)***		
	Three months ended March 31, 2017	***Year ended December 31, 2016***	***Year ended December 31, 2015***	***Three months ended March 31, 2017***	***Year ended December 31, 2016***	***Year ended December 31, 2015***
Residential	$ 120,101	$ 339,210	$ 335,552	1,213	3,528	3,571
Commercial	78,021	305,613	308,210	809	3,183	3,197
Industrial	25,973	107,296	111,770	424	1,763	1,812
Public street and highway lighting	1,895	7,662	7,277	5	23	23
Total Retail	$ 225,990	$ 759,781	$ 762,809	2,451	8,497	8,603
Wholesale	21,883	112,071	127,253	721	2,998	3,145
Sale of fuel	14,940	78,334	82,853			
Other	7,985	28,492	25,839			
Decoupling	(7,080)	17,349	4,740			
Provisions for earnings share	-	932	(5,621)			
Total electric operating revenues	$ 263,718	$ 996,959	$ 997,873			
Total electric energy sales				3,172	11,495	11,748

Avista Utilities Natural Gas Operations Statistics

The following table presents Avista Utilities' operating revenues and therms delivered for its natural gas operations for the three months ended March 31, 2017 and the years ended December 31, 2016 and December 31, 2015 (U.S. dollars in thousands):

Avista Utilites Natural Gas Operating Statistics

	Operating Revenues (thousand US$)			***Therms Delivered (thousands of therms)***		
	Three months ended March 31, 2017	***Year ended December 31, 2016***	***Year ended December 31, 2015***	***Three months ended March 31, 2017***	***Year ended December 31, 2016***	***Year ended December 31, 2015***
Residential	$ 91,425	$ 195,275	$ 193,825	96,748	186,565	176,613
Commercial	43,948	92,978	96,751	56,824	112,686	107,894
Interruptible	625	2,179	2,782	1,701	5,700	4,708
Industrial	1,313	3,348	3,792	2,149	5,234	5,070
Total Retail	$ 137,311	$ 293,780	$ 297,150	157,422	310,185	294,285
Wholesale	36,610	153,446	204,289	128,422	684,317	809,132
Transportation	2,591	8,339	7,988	55,477	178,377	164,679
Other	1,657	5,787	5,578	238	378	335
Decoupling	(7,957)	12,309	6,004			
Provisions for earnings share	-	(2,767)	0			
Total natural gas operating revenues	$ 170,212	$ 470,894	$ 521,009			
Total therms delivered				341,559	1,173,257	1,268,431

Alaska Electric Light and Power Company

Three months ended March 31, 2017 compared to the three months ended March 31, 2016

Net income for AEL&P was US$3.9 million for the three months ended March 31, 2017 compared to US$3.0 million for the three months ended March 31, 2016.

The increase in earnings was primarily due to an increase in gross margin, partially offset by an increase in operating expenses and a decrease in equity-related AFUDC due to the construction of an additional back-up generation plant in 2016.

The increase in gross margin was primarily related to an interim general rate increase, effective in November 2016, and an increase in electric heating loads due to weather that was colder than the prior year and colder than normal. This was partially offset by an increase in resource costs primarily due to purchased power expense and deferred power supply expenses.

While the cold weather did have some effect on AEL&P revenues during 2017, AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, its revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods.

Year end 2016 compared to year end 2015

Net income for AEL&P was US$8.0 million for the year ended December 31, 2016, compared to US$6.6 million for 2015. The increase in earnings for 2016 was primarily due to an increase in gross margin and an increase in equity-related AFUDC (increased earnings) due to the construction of an additional back-up generation plant which was completed during the fourth quarter of 2016.

The increase in gross margin was primarily related to a decrease in costs associated with the Snettisham hydroelectric project (due to a refinancing transaction during the second half of 2015 which lowered interest costs under the take-or-pay power purchase agreement), as well as an interim rate increase effective in November 2016. These were partially offset by a slight decrease in sales volumes to commercial and government customers and an increase in other resource costs.

AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, its revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods.

For further information on the financial condition and results of Avista Corp., reference is made to the audited comparative consolidated financial statements of Avista Corporation as at December 31, 2016 and 2015, including the consolidated balance sheets and the related consolidated statements of income, common stockholders' equity and cash flows, for each of the years ended December 31, 2016 and 2015, and the unaudited interim comparative consolidated financial statements of Avista Corporation for the three months ended March 31, 2017, each of which is included in this Prospectus.

Properties

Avista Utilities

Generation Properties

Substantially all of Avista Utilities' properties are subject to the lien of Avista Corporation's mortgage indenture.

Avista Corp.'s utility electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

	No. of Units	Nameplate Rating (MW)(1)	Present Capability (MW)(2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	88.0
Little Falls (Spokane)	4	32.0	35.6
Nine Mile (Spokane)(3)	4	36.8	29.0
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork)(4)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		931.2	1,028.6
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste)(5)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas)(5)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.6
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 & 4 (simple-cycle, coal)(6)	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	295.0	295.0
Total Thermal		839.2	833.3
Total Generation Properties		1,770.4	1,861.9

(1) Nameplate rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2016.

(3) The project to replace Units 1 and 2 was completed during 2016. The present capability shown is the maximum plant generation Avista Utilities have seen given the water they have had available, because they have not yet had peak water conditions since Units 1 and 2 went into service. As conditions change, Avista Utilities will test plant capability and revise this number accordingly.

(4) For Cabinet Gorge, Avista Utilities has water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above Avista Utilities' water rights, Avista Utilities is able to generate above its water rights. If natural stream flows only allow for generation at or below 265 MW, Avista Utilities is limited to generation of 265 MW. The present capability disclosed above represents the capability based on maximum stream flow conditions when Avista Utilities has been allowed to generate above its water rights.

(5) These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.

(6) Jointly owned; data refers to Avista Utilities' 15 percent interest.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. Avista Utilities has an electric transmission system of 685 miles of 230 KV line and 1,565 miles of 115 KV line. Avista Utilities also owns an 11 percent interest in approximately 500 miles of a 500 KV line between Colstrip, Montana and Townsend, Montana. Its transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

The 230 KV lines are the backbone of Avista Utilities' transmission grid and are used to transmit power from generation resources, including Noxon Rapids, Cabinet Gorge and the Mid-Columbia hydroelectric projects, to the major load centers in Avista Utilities service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company and serve as points of delivery for power from generating facilities outside of Avista Utilities service area, including Colstrip, Coyote Springs 2 and the Lancaster Plant.

These lines also provide a means for Avista Utilities to optimize resources by entering into short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

The 115 KV lines provide for transmission of energy and the integration of smaller generation facilities with Avista Utilities service-area load centers, including the Spokane River hydroelectric projects, the Kettle Falls projects, Rathdrum CT, Boulder Park GS and the Northeast CT. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp and Pend Oreille County PUD. Both the 115 KV and 230 KV interconnections with the BPA are used to transfer energy to facilitate service to each other's customers that are connected through the other's transmission system. Avista Utilities holds a long-term transmission agreement with the BPA that allows them to serve their native load customers that are connected through the BPA's transmission system.

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,400 miles in Washington, 2,000 miles in Idaho and 2,300 miles in Oregon. It has natural gas transmission mains of approximately 75 miles in Washington and 50 miles in Oregon. Its natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

Avista Utilities owns a one-third interest in Jackson Prairie.

Alaska Electric Light and Power Company

Generation Properties

Substantially all of AEL&P's utility properties are subject to the lien of the AEL&P mortgage indenture.

AEL&P's utility electric properties, located in Alaska include the following:

	No. of Units	Nameplate Rating (MW)(1)	Present Capability (MW)(2)
Hydroelectric Generating Stations			
Snettisham(3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	51.8
Auke Bay	3	28.4	25.2
Gold Creek	5	8.2	7.0
Industrial Blvd. Plant	1	23.5	23.5
Total Diesel		121.5	107.5
Total Generation Properties		228.1	210.2

(1) Nameplate rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2016.

(3) AEL&P does not own this generating facility but has a PPA under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility.

In addition to the generation properties above, AEL&P owns approximately 61 miles of transmission lines, which are primarily comprised of 69 KV line, and approximately 184 miles of distribution lines.

Legal Proceedings

In the course of its business, Avista Corp. becomes involved in various claims, controversies, disputes and other contingent matters. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, Avista Corp. intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' or AEL&P's operations, Avista Corp. intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to the California Parties. The penalty arises as a result of the FERC finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy's share of APX's exposure to be as much as US$16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its 2014 settlement with the California Parties insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX's assertions of indirect liability, but cannot at this time predict the eventual outcome.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels ("**Total Dissolved Gas**" or "**TDG**") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the CFSA as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista Corp. is reducing TDG by constructing spill crest modifications on spill gates at the dam, and Avista Corp. expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, Avista Corp. will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the *Endangered Species Act*. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, Avista Corp. evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA are working to resolve several issues. Avista Corp. believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, Avista Corp. will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Other Contingencies

In the normal course of business, Avista Corp. has various other legal claims and contingent matters outstanding. Avista Corp. believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows.

Environmental Issues and Contingencies

Avista Corp. is subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which they have ownership interests are designed and operated in compliance with applicable environmental laws. Furthermore, Avista Corp. conducts periodic reviews and audits of pertinent facilities and operations to ensure compliance and to respond to or anticipate emerging environmental issues. Avista Corporation's board of directors has established a committee to oversee environmental issues.

Avista Corp. monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of their generating plants and other assets.

Environmental laws and regulations may:

- increase the operating costs of generating plants;
- increase the lead time and capital costs for the construction of new generating plants;
- require modification of its existing generating plants;
- require existing generating plant operations to be curtailed or shut down;
- reduce the amount of energy available from its generating plants;
- restrict the types of generating plants that can be built or contracted with;

- require construction of specific types of generation plants at higher cost; and
- increase costs of distributing natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. Avista Corp. intends to seek recovery of any such costs through the ratemaking process.

Clean Air Act

Avista Corp. must comply with the requirements under the CAA in operating its thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip (expires in 2017), Coyote Springs 2 (expires in 2018), the Kettle Falls GS (application has been made for a new permit), and the Rathdrum CT (application has been made for a new permit). Boulder Park GS, Northeast CT, and other activities only require minor source operating or registration permits based on their limited operation and emissions. The Title V operating permits are renewed every five years and updated to include newly applicable CAA requirements. Avista Corp. actively monitors legislative, regulatory and program developments within the CAA that may impact its facilities.

On March 6, 2013, the Sierra Club and Montana Environmental Information Center, filed a Complaint ("**Complaint**") in the United States District Court for the District of Montana, Billings Division, against the owners of Colstrip. The Complaint alleged certain violations of the CAA. On July 12, 2016, all of the parties to this action filed a Consent Decree with the Court settling all claims contained in the Complaint.

Hazardous Air Pollutants

The EPA regulates HAPs from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the MATS for the coal and oil-fired source category. At the time of issuance in 2012, Avista Corp. examined the existing emission control systems of Colstrip Units 3 & 4, the only units in which Avista Corp. are a minority owner, and concluded that the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilized Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners reviewed recent stack testing data and expected that no additional emission control systems would be needed for Units 3 & 4 MATS compliance.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make "reasonable progress" through 10-year plans, including application of BART requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan ("**FIP**") for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4, the only units of which Avista Corp. are a minority owner, are not currently affected, but will be evaluated for Reasonable Progress at the next review period. Avista Corp. does not anticipate any material impacts on Units 3 & 4 at this time.

Coal Ash Management/Disposal

On April 17, 2015, the EPA published a final rule regarding CCRs, also termed coal combustion byproducts or coal ash in the Federal Register, and this rule became effective on October 15, 2015. Colstrip, of which Avista Corp. is a 15 percent owner of Units 3 & 4, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the *Resource Conservation and Recovery Act*, the primary law in the United States for regulating solid waste. Avista Corp., in conjunction with the other owners, are developing a multi-year compliance plan to strategically address the new CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule and based on the initial assessments, Avista Corp. recorded an increase to its asset retirement obligations of US$12.5 million with a corresponding increase in the cost basis of the utility plant. During 2016, due to additional information and updated estimates, Avista Corp. increased the ARO to US$13.6 million (including accretion of US$0.7 million).

In addition to an increase to Avista Corp.'s ARO, it is expected that there will be significant compliance costs at Colstrip in the future, both operating and capital costs, due to a series of incremental infrastructure improvements which are separate from the ARO.

The actual asset retirement costs and future compliance costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased ARO due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. Avista Corp. will coordinate with the plant operators and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO and future nonretirement compliance costs for these changes in estimates, which could be material. Avista Corp. expects to seek recovery of any increased costs related to complying with the new rule through customer rates.

Climate Change

Concerns about long-term global climate changes could have a significant effect on Avista Corp.'s business. Avista Corp.'s operations could also be affected by changes in laws and regulations intended to mitigate the risk of, or alter global climate changes, including restrictions on the operation of their power generation resources and obligations imposed on the sale of natural gas. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of streamflows, which impact hydroelectric generation. Extreme weather events could increase service interruptions, outages and maintenance costs. Changing temperatures could also increase or decrease customer demand.

Avista Corp.'s Climate Policy Council (an interdisciplinary team of management and other employees):

- facilitates internal and external communications regarding climate change issues,
- analyzes policy effects, anticipates opportunities and evaluates strategies for Avista Corp., and
- develops recommendations on climate related policy positions and action plans.

Climate Change - Federal Regulatory Actions

The EPA released the final rules for the Clean Power Plan ("**Final CPP**") and the Carbon Pollution Standards ("**Final CPS**") on August 3, 2015. The Final CPP and the Final CPS are both intended to reduce the CO2 emissions from certain coal-fired and natural gas electric generating units ("**EGUs**"). These rules were published in the Federal Register on October 23, 2015 and were immediately challenged via lawsuits by other parties.

In a separate but related rulemaking, the EPA finalized CO2 new source performance standards ("**NSPS**") for new, modified and reconstructed fossil fuel-fired EGUs under CAA section 111(b). These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as "**utility boilers and IGCC units**"), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas.

The promulgated and proposed greenhouse gas rulemakings mentioned above have been legally challenged in multiple venues. On February 9, 2016, the U.S. Supreme Court granted a request for stay, halting implementation of the CPP. On March 28, 2017, the Department of Justice has filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit ("**D.C. Circuit**") requesting that the Court hold the cases challenging the CPP in abeyance while the EPA reviews the final rules applicable to existing, as well as to new, modified, and reconstructed electric generating units pursuant to an Executive Order issued by President Trump. The Executive Order also instructed the EPA to review the CPP rule. On April 28, 2017 the D.C. Circuit issued orders to hold the litigation regarding the Clean Air Act §111(d) Clean Power Plan and the §111(b) New Source Performance Standards for power plants in abeyance for a period of 60 days with status reports due from EPA every 30 days. The D.C. Circuit ordered the parties to file supplemental briefs by May 15, 2017 on whether the rules should be remanded to EPA, rather than having the case held in abeyance. Given this development and related ongoing legal challenges, Avista Corp. cannot fully predict the outcome or estimate the extent to which its facilities may be impacted by these regulations at this time. Avista Corp. intends to seek recovery of any costs related to compliance with these requirements through the ratemaking process.

Climate Change - State Legislation and State Regulatory Activities

The states of Washington and Oregon have adopted non-binding targets to reduce GHG emissions. Both states enacted their targets with an expectation of reaching the targets through a combination of renewable energy standards, and assorted "complementary policies," but no specific reductions are mandated.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve retail loads in their jurisdictions. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants, that in any case, have emission levels higher than 1,100 pounds of GHG per MWh. Commerce initiated a process to adopt a lower emissions performance standard in 2012; any new standard will be applicable until at least 2017. Commerce published a supplemental notice of proposed rulemaking on January 16, 2013 with a new emissions performance standard of 970 pounds of GHG per MWh. Avista Corp. will engage in the next process to revise the emissions performance standard, which should occur in 2017.

Washington

Energy Independence Act

The EIA in Washington requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in Washington in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. The renewable energy standard increased from three percent in 2012 to nine percent in 2016. Failure to comply with renewable energy and efficiency standards could result in penalties of US$50 per MWh or greater assessed against a utility for each MWh it is deficient in meeting a standard. Avista Corp. has met, and will continue to meet, the requirements of EIA through a variety of renewable energy generating means, including, but not limited to, some combination of hydro upgrades, wind, biomass and renewable energy credits. In 2012, EIA was amended in such a way that Avista Utilities' Kettle Falls GS and certain other biomass energy facilities, which commenced operation before March 31, 1999, are considered resources that may be used to meet the renewable energy standards.

Clean Air Rule

In September 2016, Ecology adopted the CAR to cap and reduce GHG emissions across the State of Washington in pursuit of the State's GHG goals, which were enacted in 2008 by the Legislature. The CAR applies to sources of annual GHG emissions in excess of 100,000 tons for the first compliance period of 2017 through 2019; this threshold incrementally decreases to 70,000 metric tons beginning in 2035. The rule affects stationary sources and transportation fuel suppliers, as well as natural gas distribution companies. Ecology has identified approximately 30 entities that would be regulated under the CAR. Parties covered by the regulation must reduce emissions by 1.7 percent annually until 2035. Compliance can be demonstrated by achieving emission reductions and/or surrendering ERUs, which are generated by parties that achieve reductions greater than required by the rule. ERUs can also take the form of renewable energy credits from renewable resources located in Washington, carbon emission offsets, and allowances acquired from an organized cap and trade market, such as that operating in California. In addition to the CAR's applicability to their burning of fuel as an electric utility, the CAR applies to Avista Corp.as a natural gas distribution company, for the emissions associated with the use of the natural gas Avista Corp. provides its customers who are not already covered under the regulation.

In September 2016, the Petitioners jointly filed an action in the U.S. District Court for the Eastern District of Washington challenging Ecology's recently promulgated CAR. The four companies also filed litigation in Thurston County Superior Court.

Petitioners believe that the reduction of GHG emissions is a matter that needs to be addressed, but the CAR is not the solution. Each utility represented in this case provided feedback and public comment to improve the rule, but ideas put forward were not incorporated in the final rule. They are asking the U.S District Court and the Thurston County Superior Court to find that the CAR is invalid.

In their State claim, Petitioners assert that:

- Ecology lacks statutory authority to regulate natural gas utilities because the CAR holds them responsible for the indirect emissions of their customers;

- Ecology does not have the authority to create an emission reduction trading program (“**ERUs**”);
- Ecology failed to comply with the requirements of the *State Environmental Policy Act*; and
- the CAR is arbitrary and capricious.

Petitioners' federal claim asserts that the CAR violates the dormant Commerce Clause of the U.S. Constitution by discriminating against interstate commerce, regulating extraterritorially and unduly burdening interstate commerce by restricting the use of ERU’s (allowances) generated from outside the State of Washington for compliance purposes. The case in U.S. District Court has been tolled while the state court case proceeds, with oral arguments scheduled for the spring of 2017.

Initiative I-732

An Initiative to the Legislature (“**I-732**”) to impose a carbon tax on fossil-fueled generation and natural gas distribution, as well as on transportation fuels, was submitted to the Legislature in January 2016. The Legislature failed to act upon the measure and I-732 was referred to the November 2016 General Election ballot, where it failed to gain enough votes for enactment.

Colstrip 3 & 4 Considerations

On February 6, 2014, the WUTC issued a letter finding that PSE’s 2013 Electric Integrated Resource Plan meets the requirements of the Revised Code of Washington and the Washington Administrative Code. In its letter, however, the WUTC expressed concern regarding the continued operation of the Colstrip plant as a resource to serve retail customers. Although the WUTC recognized that the results of the analyses presented by PSE “differed significantly between Colstrip Units 1 & 2 and Units 3 & 4,” the WUTC did not limit its concerns solely to Colstrip Units 1 & 2. The WUTC recommended that PSE “consult with WUTC staff to consider a Colstrip Proceeding to determine the prudency of any new investment in Colstrip before it is made or, alternatively, a closure or partial-closure plan.” As part of the Sierra Club litigation that was settled in 2016, Units 1 & 2 are scheduled to close by July 2022. As a 15 percent owner of Colstrip Units 3 & 4, Avista Corp. cannot estimate the effect of such proceeding, should it occur, on the future ownership, operation and operating costs of our share of Colstrip Units 3 & 4. Our remaining investment in Colstrip Units 3 & 4 as of December 31, 2016 was US$131.0 million.

In Oregon, legislation was enacted in 2016 which requires Portland General Electric and PacifiCorp to remove coal-fired generation from their Oregon rate base by 2030. This legislation does not directly relate to Avista Corp. because Avista Corp. is not an electric utility in Oregon. However, because these two utilities, along with Avista Corp., hold minority interests in Colstrip, the legislation could indirectly impact Avista Corp., though specific impacts cannot be identified at this time. While the legislation requires Portland General Electric and PacifiCorp to eliminate Colstrip from their rates, they would be permitted to sell the output of their shares of Colstrip into the wholesale market or, as is the case with PacifiCorp, reallocate the plant to other states. Avista Corp. cannot predict the eventual outcome of actions arising from this legislation at this time or estimate the effect thereof on Avista Corp.; however, Avista Corp. will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the ESA. Efforts to protect these and other species have not significantly impacted generation levels at any of our hydroelectric facilities, nor operations of our thermal plants or electrical distribution and transmission system. Avista Corp. is implementing fish protection measures at its hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued March 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within the Spokane River Project area, and issued a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be resolved through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses.

Various statutory authorities, including the *Migratory Bird Treaty Act*, have established penalties for the unauthorized take of migratory birds. Because Avista Corp. operates facilities that can pose risks to a variety of such birds, they have developed and follow an avian protection plan.

Avista Corp. is also aware of other threatened and endangered species and issues related to them that could be impacted by their operations and they make every effort to comply with all laws and regulations relating to these threatened and endangered species. Avista Corp. expects all costs associated with these compliance efforts to be recovered through the future ratemaking process.

Regulation and Regulatory Matters

General

As a public utility, Avista Corp. is subject to regulation by state utility commissions for prices, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. Avista Corp. is also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Since Avista Corp. is a "holding company" (in addition to being itself an operating utility), it is also subject to the jurisdiction of the FERC under the *Public Utility Holding Company Act of 2005*, which imposes certain reporting and other requirements. Avista Corporation, and all of its subsidiaries (whether or not engaged in any energy related business), are required to maintain books, accounts and other records in accordance with the FERC regulations and to make them available to the FERC and the state utility commissions. In addition, upon the request of any jurisdictional state utility commission, or of Avista Corp., the FERC would have the authority to review assignment of costs of non-power goods and administrative services among Avista Corp. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions of any affiliated company.

Avista Corp.'s rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis.

Rates are designed to provide an opportunity for Avista Corp. to recover allowable operating expenses and earn a return of and a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the utility commissions. Avista Corp.'s operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made on the basis of revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, unexpected changes in revenues, expenses and investment following the time new retail rates are requested in the rate proceeding, the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment.

Avista Corp.'s rates for wholesale electric and natural gas transmission services are based on either "cost of service" principles or market-based rates as set forth by the FERC.

Avista Utilities – Washington General Rate Cases

2015 General Rate Cases

In January 2016, Avista Utilities received an order ("**Order 05**") that concluded its electric and natural gas general rate cases that were originally filed with the WUTC in February 2015. New electric and natural gas rates were effective on January 11, 2016. The WUTC-approved rates were designed to provide a 1.6 percent, or US$8.1 million decrease in electric base revenue, and a 7.4 percent, or US$10.8 million increase in natural gas base revenue. The WUTC also approved an ROR on rate base of 7.29 percent, with a common equity ratio of 48.5 percent and a

9.5 percent ROE. On January 19, 2016, the ICNU and the PC filed a Joint Motion for Clarification with the WUTC. On February 19, 2016, the WUTC issued an order ("**Order 06**") denying the motions and affirming Order 05, including an US$8.1 million decrease in electric base revenue. On March 18, 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's Order 05 and Order 06 described above that concluded Avista Utilities' 2015 electric and natural gas general rate cases. The new rates established by Order 05 will continue in effect while the Petition for Judicial Review is being considered. Avista Utilities believes the WUTC's Order 05 and Order 06 finalizing the electric and natural gas general rate cases provide a reasonable end result for all parties. If the outcome of the judicial review were to result in an electric rate reduction greater than the decrease ordered by the WUTC, it may not provide us with a reasonable opportunity to earn the rate of return authorized by the WUTC.

2016 General Rate Cases

On December 15, 2016, the WUTC issued an order related to Avista Utilities' Washington electric and natural gas general rate cases that were originally filed with the WUTC in February 2016. The WUTC order denied Avista Utilities' proposed electric and natural gas rate increase requests of US$38.6 million and US$4.4 million, respectively. On December 23, 2016 Avista Utilities filed a Petition for Reconsideration or, in the alternative, Rehearing ("**Petition**") with the WUTC related to its 2016 general rate cases. On February 27, 2017, Avista Utilities received an order from the WUTC denying our Petition and confirming its previous order in the case.

Avista Utilities determined that an appeal of the WUTC's decision to the courts would involve a significant amount of uncertainty regarding the level of success of such an appeal, as well as the timing of any value that might come following a process that would take between one and two years. Avista Utilities believes greater long-term value can be achieved through focusing on the 2017 general rate cases rather than through appealing the recent decision in the courts.

2017 General Rate Cases

On May 26, 2017, Avista Utilities filed two requests with the WUTC to recover costs related to power supply as well as infrastructure, system maintenance, and technology.

The two filings are summarized as follows:

Power Cost Rate Adjustment

The first filing is an electric only power cost rate adjustment that would update and reset power supply costs, effective September 1, 2017. Avista Utilities requested an overall increase in billed electric rates of 2.9 percent (designed to increase annual electric revenues by US$15.0 million). The key drivers behind this request are related to the expiration of a capacity sales agreement with another utility and an increase in the price of natural gas to fuel our generating plants. Any new rates resulting from the power cost rate adjustment would expire upon the conclusion of the electric general rate case (discussed in further detail below), if approved. Avista Utilities expects the WUTC to address the power cost rate adjustment by August 10, 2017, in which they will either approve or deny the request or indicate additional steps that may be necessary.

General Rate Requests

The second request relates to electric and natural gas general rate cases. Avista Utilities filed three-year rate plans for electric and natural gas and have requested the following for each year (U.S. dollars in millions):

	Electric		Natural Gas	
Effective Date	Proposed Revenue Increase	Proposed Base Rate Increase	Proposed Revenue Increase	Proposed Base Rate Increase
May 1, 2018 (1)	$ 61.4	12.5%	$ 8.3	9.3%
May 1, 2019 (2)	$ 14.0	2.5%	$ 4.2	4.4%
May 1, 2020 (2)	$ 14.4	2.5%	$ 4.4	4.4%

(1) The US$61.4 million electric revenue increase includes the US$15.0 million power cost rate adjustment discussed above.

(2) As a part of the electric rate plan, Avista Utilities has proposed to update power supply costs through a Power Supply Update, the effects of which would also go into effect on May 1, 2019 and May 1, 2020. The requested revenue increases for 2019 and 2020 do not include any power supply adjustments.

Avista Utilities request is based on a proposed ROR of 7.76 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE. As a part of the three-year rate plan, if approved, Avista Utilities would not file another general rate case until June 1, 2020, with new rates effective no earlier than May 1, 2021. The WUTC has up to 11 months to review the general rate case filings and issue a decision.

Idaho General Rate Cases

2016 General Rate Cases

In December 2016, the IPUC approved a settlement agreement between Avista Utilities and other parties in their electric general rate case, concluding the Idaho electric general rate case originally filed in May 2016. New rates took effect on January 1, 2017 under the settlement agreement. Avista Utilities did not file a natural gas general rate case in 2016. The settlement agreement increased annual electric base rates by 2.6 percent (designed to increase annual electric revenues by US$6.3 million). The settlement revenue increase is based on a ROR of 7.58 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

2017 General Rate Cases

On June 9, 2017, Avista Utilities filed electric and natural gas general rate requests with the IPUC to recover increased power supply costs and capital investments made since the last determination of Avista Utilities' rate base in the 2016 Idaho general rate case. Avista Utilities filed two-year rate plans for electric and natural gas and have requested the following for each year (U.S. dollars in millions):

	Electric		Natural Gas	
Effective Date	Proposed Revenue Increase	Proposed Base Rate Increase	Proposed Revenue Increase	Proposed Base Rate Increase
January 1, 2018	$ 18.6	7.5%	$ 3.5	8.8%
January 1, 2019 (1)	$ 9.9	3.7%	$ 2.1	5.0%

(1) Avista Utilities is not proposing to update base power supply costs for year two of the rate plan, but rather have any differences flow through the PCA mechanism.

Avista Utilities' requests are based on a proposed ROR of 7.81 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE. As a part of the two-year rate plan, if approved, Avista Utilities would not file a new general rate case for a new rate plan to be effective prior to January 1, 2020. The IPUC has up to nine months to review the general rate case filings and issue a decision.

Oregon General Rate Cases

2015 General Rate Case

On February 29, 2016, the OPUC issued a preliminary order (and a final order on March 15, 2016) concluding Avista Utilities' natural gas general rate case, which was originally filed with OPUC in May 2015. The OPUC order approved rates designed to increase overall billed natural gas rates by 4.9 percent (designed to increase annual natural gas revenues by US$4.5 million). New rates went into effect on March 1, 2016. The final OPUC order incorporated two partial settlement agreements which were entered into during November 2015 and January 2016.

2016 General Rate Case

On May 17, 2017, Avista Utilities reached a settlement agreement with all parties involved in its natural gas general rate case and the settlement agreement was filed with the OPUC. If the settlement agreement is approved by the OPUC, new rates would take effect on October 1, 2017.

The settlement proposes that, effective October 1, 2017, Avista Utilities would receive an increase in rates designed to increase annual base revenues by 5.9 percent or US$3.5 million. In addition, the order denied the recovery of certain utility plant expenditures, which resulted in a disallowance and write-off of approximately US$0.8 million in the second quarter of 2017.

The proposed settlement agreement reflects a 7.35 ROR with a common equity ratio of 50 percent and a 9.4 percent ROE.

Alaska Electric Light and Power Company

Alaska General Rate Case

In September 2016, AEL&P filed an electric general rate case with the RCA. AEL&P was granted a refundable interim base rate increase of 3.86 percent (designed to increase electric revenues by US$1.3 million), which took effect in November 2016. AEL&P has also requested a permanent base rate increase of an additional 4.24 percent (designed to increase electric revenues by US$1.5 million), which, if approved, could take effect in February 2018. This represents a combined total rate increase of 8.1 percent (designed to increase electric revenues by US$2.8 million).

The RCA must rule on permanent rate increase requests within 450 days (approximately 15 months) from the date of filing, unless otherwise extended by consent of the parties. The statutory timeline for the AEL&P general rate case, with the consent of the parties, has been extended to February 8, 2018.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, Avista Utilities absorbs (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of US$31.0 million as of March 31, 2017 and a liability of US$30.8 million as of December 31, 2016, and these deferred natural gas costs balances represent amounts due to customers.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of US$21.6 million as of March 31, 2017 compared to a liability of US$21.3 million as of December 31, 2016, and these deferred power cost balances represent amounts due to customers.

The difference in net power supply costs under the ERM primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

Under the ERM, Avista Utilities absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is US$4.0 million.

Decoupling and Earnings Sharing Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes, rather than kilowatt hour and therm sales. The difference between revenues based on the number of customers and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved Avista Utilities' decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the prior calendar year. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments.

- If Avista Utilities has a decoupling rebate balance for the prior year and earns in excess of the authorized ROR (7.32 percent for 2015 and 7.29 percent for 2016), the rebate to customers would be increased by 50 percent of the earnings in excess of the authorized ROR.

- If Avista Utilities has a decoupling rebate balance for the prior year and its earnings are equal to or less than the authorized ROR, only the base amount of the rebate to customers would be made.

- If Avista Utilities has a decoupling surcharge balance for the prior year and earns in excess of the authorized ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the authorized ROR (or eliminated). If 50 percent of the earnings in excess of the authorized ROR exceeds the decoupling surcharge balance, the dollar amount that exceeds the surcharge balance would create a rebate balance for customers.

- If Avista Utilities has a decoupling surcharge balance for the prior year and its earnings are equal to or less than the authorized ROR, the base amount of the surcharge to customers would be made.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, beginning January 1, 2016.

For the period 2013 through 2015, Avista Corp. had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, it would be required to share with customers 50 percent of any earnings above the 9.8 percent. There was no provision for a surcharge to customers if its ROE was less than 9.8 percent. This after-the-fact earnings test was discontinued as part of the settlement of Avista Corp.'s 2015 Idaho electric and natural gas general rates cases.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. An earnings review is conducted on an annual basis, which is filed by Avista Corp. with the OPUC on or before June 1 of each year for the prior calendar year. In the annual earnings review, if Avista Corp. earns more than 100 basis points above its allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later returned to customers.

Liquidity, Capital Resources and Financing Activities

Avista Corporation's consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities include the purchase of power, fuel and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends.

Committed Lines of Credit

Avista Corporation has a committed line of credit with various financial institutions in the total amount of US$400.0 million. Avista Corporation exercised a two-year option in May 2016 to extend the maturity of the credit facility agreement to April 2021. As of March 31, 2017, there were US$105.0 million of cash borrowings and US$42.1 million in letters of credit outstanding (which were primarily issued as collateral for Avista Corporation's energy commodity and interest rate swap derivatives), leaving US$252.9 million of available liquidity under this line of credit.

The Avista Corporation credit facility contains customary covenants and default provisions, including a covenant which does not permit its ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of March 31, 2017, Avista Corporation is in compliance with this covenant with a ratio of 52.2 percent.

AEL&P has a US$25.0 million committed line of credit that expires in November 2019. As of March 31, 2017, there were no borrowings or letters of credit outstanding under this committed line of credit.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of March 31, 2017, AEL&P was in compliance with this covenant with a ratio of 54.6 percent.

Competition

Avista Corp.'s utility electric and natural gas distribution business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, its rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity for it to earn a reasonable return on investment as allowed by its regulators.

In retail markets, Avista Corp. compete with various rural electric cooperatives and public utility districts in and adjacent to its service territories in the provision of service to new electric customers. Alternative energy technologies, including customer-sited solar, wind or geothermal generation, may also compete with it for sales to existing customers. While the risk is currently small in its service territory given the small numbers of customers utilizing these technologies, advances in power generation, energy efficiency, energy storage and other alternative energy technologies could lead to more wide-spread usage of these technologies, thereby reducing customer demand for the energy supplied by Avista Corp. This reduction in usage and demand would reduce Avista Corp.'s revenue and negatively impact its financial condition including possibly leading to its inability to fully recover its investments in generation, transmission and distribution assets. Similarly, Avista Corp.'s natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could bypass Avista Corp.'s natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such bypass, Avista Corp. prices its natural gas services, including transportation contracts, competitively and have varying degrees of flexibility to price transportation and delivery rates by means of individual contracts. These individual contracts are subject to state regulatory review and approval. Avista Corp. has long-term transportation contracts with several of its largest industrial customers under which the customer acquires its own commodity while using Avista Corp.'s infrastructure for delivery. Such contracts reduce the risk of these customers bypassing Avista Corp.'s system in the foreseeable future and minimizes the impact on its earnings.

Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that may improve productivity and could alter demand for the energy Avista Corp. sells.

In wholesale markets, competition for available electric supply is influenced by the:

- localized and system-wide demand for energy,

- type, capacity, location and availability of generation resources, and
- variety and circumstances of market participants.

These wholesale markets are regulated by the FERC, which requires electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers,
- enlarge or construct additional transmission capacity for the purpose of providing these services, and
- transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,
- independent power producers,
- financial institutions, and
- commodity brokers.

Credit Ratings

Avista Corporation's corporate credit ratings and the ratings for its securities are as follows:

Period	S&P(1)	Moody's(2)
Corporate/Issuer rating	BBB	Baa1
Senior secured debt	A-	A2
Senior unsecured debt	BBB	Baa1

(1) S&P's lowest "investment grade" credit rating is BBB-.
(2) Moody's lowest "investment grade" credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered independently of all other ratings.

See "Recent Developments".

For additional information on Avista Corp. see pages A-9 and A-10 of the Investor Presentation attached as Appendix A to this Prospectus.

THE MERGER AGREEMENT

Set forth below is a description of the material terms of the Merger Agreement. The description is a summary only and is qualified in its entirety by the full text of the Merger Agreement. A copy of the Merger Agreement has been filed on the Corporation's SEDAR profile at www.sedar.com. This summary is not intended to be, and should not be relied upon as disclosure of any facts and circumstances relating to Hydro One or Avista Corp. All capitalized terms used herein without definition will have the meanings assigned to them in the Merger Agreement, a copy of which will is available on the Corporation's SEDAR profile at www.sedar.com.

The Merger

On July 19, 2017, the Corporation, US Parent, Merger Sub and Avista Corporation entered into the Merger Agreement. Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been approved by the board of directors of both Avista Corporation and Hydro One Limited, at the effective time upon the closing of the Merger, Merger Sub will merge with and into Avista Corporation with Avista Corporation continuing as the surviving corporation. US Parent is an indirect, wholly owned subsidiary of the Corporation, and Merger Sub is a direct, wholly-owned subsidiary of US Parent and, at the effective time of the closing of the Merger, will be collectively owned by US Parent and one or more direct or indirect wholly owned subsidiaries of the Corporation.

The Merger Consideration

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of common stock, no par value, of Avista Corporation (other than shares held by shareholders exercising their dissenter's rights and shares owned by the Corporation, US Parent or Merger Sub or their respective subsidiaries to be cancelled in the Merger) will be converted automatically into the right to receive US$53.00 in cash, without interest (the "**Merger Consideration**"). The aggregate amount of Merger Consideration to be paid, including with respect to the outstanding restricted stock units (the "**RSUs**") and performance awards granted under Avista Corporation's stock incentive plans, is approximately US$3.4 billion in cash. Shareholders exercising their dissenter's rights and shares owned by the Corporation, US Parent or Merger Sub or their respective subsidiaries to be cancelled in the Merger will not be entitled to receive the Merger Consideration.

Treatment of Performance Awards and RSUs

Upon the closing of the Merger, each outstanding performance award will be cancelled and converted into the right to receive a lump sum cash payment equal to the product of (i) the Merger Consideration multiplied by (ii)(A) for any outstanding performance award for which the performance period has ended as of immediately prior to the effective time of the Merger, (1) in the case of a share-settled performance award, the number of shares of Avista Corporation common stock that would be delivered to the holder of such performance award, or (2) in the case of a cash-settled performance award, the number of shares of Avista Corporation common stock that would be deemed deliverable to the holder for purposes of calculating the cash payment due under such performance award, in each case, based on the achievement of the applicable performance goals, as reasonably determined by the board of directors of Avista Corporation (or a committee thereof) prior to the effective time of the Merger, and assuming the satisfaction of all other applicable conditions, and (B) for any outstanding performance award for which the performance period has not ended as of immediately prior to the effective time of the Merger, (1) in the case of a share-settled performance award, the number of shares of Avista Corporation common stock subject to such performance award, or (2) in the case of a cash-settled performance award, the number of shares of Avista Corporation common stock that would be deemed deliverable to the holder for purposes of calculating the cash payment due thereunder, in each case, based on deemed satisfaction of the applicable performance goals at the target level, and in each case, assuming the satisfaction of all other applicable conditions. Upon the closing of the Merger, all accrued but unpaid dividends with respect to performance awards will become fully vested and be paid in connection with the Merger.

Upon the closing of the Merger, each outstanding RSU which by its terms would vest before the calendar year or in the calendar year in which the Merger occurs will be cancelled and converted into the right to receive a lump-sum cash payment equal to the product of (i) the number of shares of Avista Corporation common stock subject to the cancelled RSU and (ii) the Merger Consideration. Upon the closing of the Merger, all accrued but unpaid dividends with respect to cancelled RSUs will become fully vested and be paid in connection with the Merger.

Upon the closing of the Merger, each outstanding RSU which by its terms would vest in any calendar year following the calendar year in which the Merger occurs will be converted into a restricted stock unit award issued under the Corporation's equity-based long-term incentive compensation plan, on the same terms and conditions as were applicable under the RSU immediately prior to the effective time of the Merger, with respect to a number of shares of common stock of the Corporation determined by multiplying (i) the number of shares of Avista Corporation common stock subject to the RSU by (ii) a fraction, the numerator of which is the Merger Consideration and the denominator of which is the closing price per share of common stock of the Corporation on the TSX on the closing date of the Merger, converted into U.S. dollars using the reported Bank of Canada noon spot exchange rate on the closing date of the Merger (or as reported by such other authoritative source mutually accepted by Avista Corporation and the Corporation), rounded up to the nearest whole share, and each such converted RSU will not be accelerated except as provided in the related RSU agreement. Upon the closing of the Merger, the Corporation will assume all obligations of Avista Corporation with respect to the Avista Corporation stock plans and each outstanding converted RSU and the original related grant agreements. The converted RSUs will be settled in shares of common stock of the Corporation or cash, as determined by the Corporation.

All amounts payable pursuant to the Merger Agreement are subject to reduction for applicable tax withholdings.

Representations and Warranties

Under the Merger Agreement, the Corporation, US Parent, Merger Sub and Avista Corporation have made various customary representations and warranties.

Avista Corporation's representations and warranties relate to, among other things: organization, standing and corporate power of Avista Corporation and its subsidiaries; capitalization; authority and non-contravention; governmental approvals; Avista Corporation SEC reports and financial statements and undisclosed liabilities; absence of certain changes; legal proceedings; compliance with applicable laws and permits; tax matters; employee benefits matters; environmental matters; intellectual property; real property; material contracts; labour and employment matters; opinion of financial advisor; brokers and other advisors; and Avista Shareholder Approval.

The representations and warranties of the Corporation, US Parent and Merger Sub relate to, among other things: organization, standing and corporate power; authority and non-contravention; governmental approvals; brokers and other advisors; ownership and operations of Merger Sub; sufficient funds; share ownership; legal proceedings; and non-reliance.

Covenants

Avista Corporation, the Corporation, US Parent and Merger Sub have made covenants regarding the conduct of the parties to the Merger Agreement during the period between the signing of the Merger Agreement and the closing of the Merger, at the closing of the Merger and after the closing of the Merger.

Except as set forth in the confidential disclosure schedules to the Merger Agreement, or otherwise contemplated or permitted by the Merger Agreement or as required by applicable law, or with the prior written consent of the Corporation (not to be unreasonably withheld, delayed or conditioned), (a) Avista Corporation has agreed, among other things, from the date of the Merger Agreement until the closing of the Merger to, and to cause each of its subsidiaries to, use its commercially reasonable efforts to conduct its business in all material respects in the ordinary course of business and to preserve intact its present lines of business, maintain its rights and franchises and preserve satisfactory relationships with governmental authorities, employees, customers and suppliers, and (b) Avista Corporation will not, and will not permit any of its subsidiaries to: (i) issue any shares of its capital stock, or any securities or rights convertible into shares of its capital stock except for (A) the issuance of any shares of Avista Corporation common stock in settlements of RSUs and performance awards or (B) the issuance of such number of shares of Avista Corporation capital stock as is equal to an equivalent value of up to US$150,000,000 in net proceeds in the aggregate through the end of 2018, as disclosed in the related confidential disclosure schedules to the Merger Agreement; (ii) redeem, repurchase or otherwise acquire any of its capital stock, except in connection with withholding shares of Avista Corporation common stock to satisfy tax obligations with respect to RSUs and performance awards or acquisitions in connection with the forfeiture of RSUs and performance awards; (iii) declare any dividend on, or make any other distribution in respect of, any shares of capital stock other than (A) dividends paid by any subsidiary of Avista Corporation to Avista Corporation or a wholly owned subsidiary of Avista Corporation, (B) quarterly cash dividends with respect to the Avista Corporation common stock not to exceed the current annual per share dividend rate by more than US$0.06 per year, consistent with Avista Corporation's current dividend practice or (C) a "stub period" dividend to holders of record of Avista Corporation common stock as of immediately prior to the effective time of the Merger; (iv) incur any indebtedness in excess of US$250,000,000 in the aggregate, except to replace existing indebtedness, pursuant to any existing contract relating to indebtedness or among Avista Corporation and any of its wholly-owned subsidiaries or among any of such wholly owned subsidiaries; (v) dispose of any of its properties or assets except (A) dispositions as to which the sales price is not in excess of US$25,000,000 in the aggregate in any calendar year, (B) pursuant to a material contract in effect as of the date of the Merger Agreement, (C) dispositions of inventory or equipment that are no longer used or useful or (D) transfers among Avista Corporation and its wholly-owned subsidiaries; (vi) make capital expenditures, except for an aggregate amount of capital expenditures in any calendar year equal to the aggregate amount budgeted in Avista Corporation's current long term plan that was made available to the Corporation prior to the date of the Merger Agreement (plus a 10% variance), excluding any acquisition expenditures permitted pursuant to item (vii) below; (vii) make any acquisition (including by merger) of capital stock or assets of any other person for consideration in excess of US$25,000,000 in the aggregate in any calendar year (not including certain capital expenditures); (viii) (A) increase the compensation or benefits of any of its directors, executive officers or employees (except in the ordinary course of business), (B) grant to any director or employee of Avista Corporation or any of its subsidiaries any increase in change-in-control, severance, retention or termination pay, or enter into or amend any change-in-control, severance, retention or termination agreement or (C) take any action to accelerate the time of vesting, funding or payment of any compensation or benefits under any Avista Corporation benefit plan, except, in each case, (X) as required pursuant to applicable law, (Y) pursuant to the terms of Avista Corporation benefit plans or collective bargaining agreements, or (Z) in the ordinary course of business consistent with past practice; (ix) establish, adopt, amend or terminate any company benefit plan except (A) as required by law or (B) for routine, immaterial or ministerial amendments; (x) make any material change to its methods of accounting, except as required by U.S. GAAP, Regulation S-X of the Exchange Act, a governmental authority or by applicable law; (xi) amend Avista Corporation's organizational documents or the organizational documents of any of its subsidiaries; (xii) adopt a plan or agreement of complete or partial liquidation or dissolution; (xiii) enter into, modify, or amend in any material respect or terminate or waive any material right under any material contracts of Avista Corp. except in the ordinary course of business or a termination without material penalty to Avista Corporation or any of its subsidiaries; (xiv) waive, settle or compromise any material claim except (A) with respect to the payment of monetary damages, a payment not exceeding US$2,000,000 in the aggregate during any twelve-month period or (B) with respect to any nonmonetary terms, would not reasonably be expected to be material and adverse to Avista Corporation and its subsidiaries; (xv) make or change any material tax election, any material method of tax accounting, amend any material tax return or settle any material tax liability; (xvi) permit any material insurance policy to terminate or lapse without replacing such policy with substantially similar coverage; (xvii) enter into any derivative transactions other than in the ordinary course of business and in a manner consistent with and in compliance with hedging polices or materially change any of its energy price or interest rate risk management guidelines; (xviii) enter into any material new line of business; (xix) take any action that would reasonably be expected to materially impede, interfere with or delay the consummation by Avista Corporation of the Merger and the related transactions contemplated by the Merger Agreement; or (xx) agree in writing to do any of the foregoing.

Under the Merger Agreement, the Corporation, US Parent and Merger Sub agreed that they will not take any action that would reasonably be expected to prevent or materially impede the consummation by the Corporation, US Parent or Merger Sub of the Merger and the related transactions contemplated by the Merger Agreement.

Between the date of the Merger Agreement and the closing of the Merger, Avista Corporation is required to continue to make regulatory filings in the ordinary course of business consistent with past practice and is permitted to respond to regulatory filings made by other parties in which Avista Corporation or any of its subsidiaries is an interested party and take other actions contemplated by the state or federal filings or submissions made in connection with regulatory filings in the ordinary course of business. Avista Corporation is required to keep the Corporation promptly informed of any material communications or meetings with any governmental authority with respect to rate cases, consult with and give the Corporation a reasonable opportunity to comment on material written communications or submissions to governmental authorities, and provide the Corporation a reasonable opportunity to participate in any related material meeting or communication. The Corporation has the right to approve (not to be unreasonably withheld, conditioned or delayed) any settlement of any rate case and rate case filing if it would reasonably be expected to result in an outcome that would be materially adverse to Avista Corporation or any of its subsidiaries after the closing of the Merger, taking into account the requests made by Avista Corp. in such rate case and the resolution of similar recent rate cases by Avista Corp.

Moreover, Avista Corporation has agreed to prepare and file with the SEC a preliminary proxy statement as promptly as reasonably practicable, but in any event within sixty days after the signing of the Merger Agreement, and the Corporation has agreed to cooperate in such preparation and filing.

Under the Merger Agreement, Avista Corporation, the Corporation, US Parent and Merger Sub are required to use reasonable best efforts to cause the Merger to be consummated as soon as practicable, make any required governmental submissions and filings and obtain all required governmental and regulatory approvals. In furtherance of the foregoing, the Corporation, US Parent and Merger Sub agreed to take all necessary steps to eliminate impediments to obtaining required regulatory approvals, except that neither the Corporation nor any of its affiliates is required to accept any term or condition in connection with obtaining the required regulatory approvals that would have or be reasonably likely to constitute a Burdensome Condition (as defined below). In the course of obtaining required regulatory approvals, Avista Corporation is not permitted to offer or agree to any concessions with regulators that would reasonably be expected to be material and adverse to the Corporation's ability to obtain required regulatory approvals on substantially the terms the Corporation reasonably expects unless Avista Corporation is so directed by the Corporation.

The Corporation has agreed that, for a period of six years after the Merger, it will cause to be maintained in effect policies of directors' and officers' liability insurance and fiduciary liability insurance no less favorable than the existing coverage, subject to a limit on the aggregate annual premiums payable of not more than 300% of the current premiums paid by Avista Corporation. In lieu of maintaining the foregoing coverage, Avista Corporation may purchase a "tail" insurance policy for a period of not less than six years, subject to the same aggregate cost limitation.

In addition, for a period of three years after the closing of the Merger, the Corporation will cause to be provided to each individual employed by Avista Corporation or its subsidiaries immediately prior to the closing of the Merger, cash compensation (including bonus and long-term incentive compensation opportunities) and employee benefits that are no less favourable than those provided to such employee, in the aggregate, immediately prior to the closing of the Merger. With respect to employees of Avista Corp. covered by a collective bargaining agreement, the Corporation will cause to be provided to such employees' terms and conditions of employment as required by the applicable collective bargaining agreement. Effective upon the closing of the Merger, the Corporation is required to cause Avista Corporation to implement a pre-agreed executive retention program.

Between the date of the Merger Agreement until the closing of the Merger, subject to certain limitations, Avista Corporation is required to use its commercially reasonable efforts to cooperate with the Corporation and its affiliates in connection with any financing transaction undertaken by the Corporation in connection with the Merger.

The Merger Agreement includes a series of governance and operational commitments and limitations, with respect to Avista Corporation that the Corporation intends to implement from and after the consummation of the Merger. From and after the closing of the Merger, the Corporation intends that the board of directors of Avista Corporation (the "**Subsidiary Board**") will consist of nine members in total, determined as follows: (i) two directors designated by the sole shareholder of Avista Corporation, who are executives of the Corporation or any of its subsidiaries, (ii) three directors who are not officers, employees or directors (other than an independent director of Avista Corporation) of the Corporation or any of its affiliates and who are residents of the Pacific Northwest region, to be designated by the sole shareholder of Avista Corporation, (iii) three directors who, as of immediately prior to the effective time of the Merger, were members of the board of directors of Avista Corporation, including the chairman of Avista Corporation's board of directors (if such person is different from the chief executive officer of Avista Corporation), and (iv) the chief executive officer of Avista Corporation. The initial chairman of the board of directors of Avista Corporation following the closing of the Merger will be the chief executive officer of Avista Corporation as of the time immediately prior to the effective time of the Merger for a one-year term. In addition, these provisions permit the Corporation to promptly remove and replace its designees to the Subsidiary Board, require prior notice of matters to discussed at meetings of the Subsidiary Board and require that a quorum of the Subsidiary Board includes at least one member who is an executive of the Corporation and at least an equal number of members designated by the Corporation as other members of the board.

Furthermore, following the closing of the Merger, commitments with respect to certain operational, governance and related matters will be required to be administered by the Subsidiary Board, subject to the approval of the sole shareholder of Avista Corporation, which will be a wholly owned, indirect subsidiary of the Corporation, with respect to specified matters. The matters to be administered by the Subsidiary Board include, among others, social commitments, decisions with respect to maintaining existing levels of charitable giving and economic development investment, maintaining Avista Corporation's brand, and maintaining the location of Avista Corporation's headquarters in Spokane, Washington, maintaining service and reliability standards, negotiations with labour unions, maintenance of existing employee compensation and benefits practices, retention of the existing executive management team and the composition of the Subsidiary Board as described above. The approval of the sole shareholder of Avista Corporation will be required, however, for decisions with respect to fundamental operational, governance and organizational matters, including, among others, entering into a merger or other business combination transaction, materially changing the nature of the business of Avista Corporation or any of its subsidiaries, winding up or dissolving Avista Corporation or any of its subsidiaries, declaring or paying dividends, changing the number of directors on the board of directors, changing employee compensation in a manner that is inconsistent with current market standards and practices, hiring or dismissing the chief executive officer and amending the organizational documents of Avista Corporation or any of its subsidiaries.

Closing Conditions

The Merger Agreement provides that the obligation of each of the Corporation, US Parent, Merger Sub and Avista Corporation to consummate the Merger is subject to the satisfaction or waiver of the following conditions:

(i) the Merger Agreement shall have been approved by the affirmative vote of the holders of a majority of the outstanding shares of Avista Corporation common stock entitled to vote at a duly convened meeting of Avista Corporation's shareholders ("**Avista Shareholder Approval**");

(ii) the governmental and regulatory consents and approvals specified in the Merger Agreement required to be obtained by the Corporation, US Parent, Merger Sub and Avista Corporation pursuant to the Merger shall have been obtained prior to the closing of the Merger, including: (A) clearance of the Merger by CFIUS and the expiration or termination of any applicable waiting period under the HSR Act and (B) the approval of the Merger by each of the IPUC, MPSC, OPUC, RCA, WUTC, the FERC and the FCC, and the required regulatory approvals and consents shall have become Final Orders; and

(iii) no law or judgment shall be in effect that prevent, prohibits or makes illegal the consummation of the Merger.

In addition, the Merger Agreement provides that the obligation of the Corporation, US Parent and Merger Sub to consummate the Merger is subject to the satisfaction or waiver of the following conditions:

(i) (A) the representations and warranties of Avista Corporation (except for the representations and warranties pertaining to capital structure and authority) shall be true and correct (without giving effect to any limitation as to "materiality" or "Avista Material Adverse Effect"), except where the failure to be true and correct has not had or would not reasonably be expected to have an Avista Material Adverse Effect; (B) the representations and warranties of Avista Corporation pertaining to capital structure shall be true and correct except where the failure of any such representation or warranty to be true and correct would be de minimis; and (C) the representations and warranties of Avista Corporation pertaining to authority and shareholder approval shall be true and correct in all material respects, in each case, as of the closing of the Merger as though made at and as of the closing of the Merger (except to the extent that such representation and warranty is expressly made as of a specified date, in which case such representation and warranty shall be true and correct as of such specific date);

(ii) Avista Corporation must have complied with all of its covenants in all material respects;

(iii) the Corporation shall have received a certificate signed by an executive officer of Avista Corporation certifying the satisfaction by Avista Corporation of the conditions set forth in items (i) and (ii) above;

(iv) no Avista Material Adverse Effect has occurred; and

(v) the Final Orders do not impose or require any obligations that would, individually or in the aggregate, constitute a Burdensome Condition.

The Merger Agreement also provides that the obligation of Avista Corporation to consummate the Merger is subject to the satisfaction or waiver of the following conditions:

(i) the representations and warranties of the Corporation, US Parent and Merger Sub shall be true and correct (without giving effect to any limitation as to "materiality" or "Corporation Material Adverse Effect"), as of the closing of the Merger with the same effect as though made on and as of the closing of the Merger (except to the extent that such representation and warranty is expressly made as of a specified date, in which case such representation and warranty shall be true and correct as of such specific date), except as would not cause a Corporation Material Adverse Effect;

(ii) the Corporation, US Parent and Merger Sub must have complied with all of their respective covenants in all material respects; and

(iii) Avista Corporation shall have received a certificate signed by an executive officer of the Corporation certifying the satisfaction by the Corporation and Merger Sub of the conditions set forth in items (i) and (ii) above.

No Solicitation; Avista Corporation's Board of Directors Recommendation

Pursuant to the terms of the Merger Agreement, Avista Corporation will, and will cause its subsidiaries and its and their respective directors, officers, employees and professional (including financial) advisors, attorneys, accountants, consultants or other representatives (acting in such capacity) ("**Representatives**") to, immediately terminate any ongoing negotiations with any person with respect to any Takeover Proposal. From and after the signing of the Merger Agreement, Avista Corporation will not and will cause its subsidiaries and Representatives not to, directly or indirectly, (i) solicit, initiate or knowingly encourage or facilitate any Takeover Proposal or (ii) enter into or participate in any discussions or negotiations with any person or furnish any nonpublic information to or cooperate with any person with respect to a Takeover Proposal. Notwithstanding the foregoing, Avista Corporation may, in response to an unsolicited Takeover Proposal made after the signing of the Merger Agreement and prior to the receipt of the Avista Shareholder Approval and that the board of directors of Avista Corporation determines in good faith could lead to a Superior Proposal, furnish information and participate in discussions with the persons making that Takeover Proposal. Avista Corporation must notify the Corporation promptly in writing of the receipt of the Takeover Proposal, its material terms and conditions, and the identity of the person making the Takeover Proposal.

Except as otherwise provided in the Merger Agreement, neither the Avista Corporation board of directors nor any committee thereof shall (i)(A) withdraw, change, qualify, withhold or modify in a manner adverse to the Corporation, or publicly propose to withdraw, change, qualify, withhold or modify in a manner adverse to the Corporation, its recommendation that Avista Corporation's shareholders approve the Merger Agreement, (B) adopt, approve or recommend, or publicly propose to adopt, approve or recommend, any Takeover Proposal, (C) fail to include its recommendation that Avista Corporation's shareholders approve the Merger Agreement in the proxy statement sent to its shareholders relating to the shareholder meeting to be held to vote on approval of the Merger Agreement or (D) in the event a tender offer that constitutes a Takeover Proposal subject to Regulation 14D under the Exchange Act is commenced, fail to recommend against such Takeover Proposal in any solicitation or recommendation statement made on Schedule 14D-9 within ten (10) business days after the Corporation so requests reaffirmation in writing (provided that the Corporation shall be entitled to make such a written request for reaffirmation only once for each Takeover Proposal and once for each material amendment to such Takeover Proposal) (any action described in this clause (i) being referred to herein as an "**Adverse Recommendation Change**") or (ii) cause or permit Avista Corporation or any of its affiliates to execute or enter into, any letter of intent, memorandum of understanding, agreement in principle, agreement or commitment constituting, or that would reasonably be expected to lead to a Takeover Proposal.

At any time prior to obtaining the Avista Shareholder Approval, the Avista Corporation board of directors may make an Adverse Recommendation Change if (i) Avista Corporation has received a Superior Proposal that does not result from a breach of the Merger Agreement, or (ii) any circumstance, development, change, event, occurrence or effect that (A) is unknown to or by Avista Corporation's board of directors as of the date of the Merger Agreement (or if known, the magnitude or material consequences of which are not known by Avista Corporation's board of directors as of the date of the Merger Agreement) and (B) becomes known to or by Avista Corporation's board of directors prior to obtaining the Avista Shareholder Approval (an "**Avista Intervening Event**"); provided, however, that neither a Takeover Proposal nor any consequence thereof shall constitute an Avista Intervening Event, in each case, if Avista Corporation's board of directors determines in good faith, after consultation with outside counsel, that the failure to make an Adverse Recommendation Change would reasonably be expected to be inconsistent with its fiduciary duties, and, provided that Avista Corporation's board of directors complies with the following requirements: (1) the Avista Corporation board of directors has provided prior written notice to the Corporation that it is prepared to change its board recommendation at least four business days prior to taking such action; (2) during the four business day period, the parties negotiate in good faith regarding any revisions to the Merger Agreement the other party proposes to make; and (3) at the end of the four business day period and taking into account any revisions of the Merger Agreement committed to in writing by the other party, the Avista Corporation board of directors determines in good faith (after consultation with outside legal counsel and a financial advisor) that the failure to make an adverse board recommendation change would be inconsistent with its fiduciary duties.

Termination

The Merger Agreement may be terminated at any time prior to the closing of the Merger, by mutual written consent of Avista Corporation or the Corporation.

Additionally, the Merger Agreement may be terminated by either Avista Corporation or the Corporation at any time prior to the closing of the Merger, if:

(i) the closing of the Merger has not occurred by the End Date; provided that if, prior to the End Date, all of the conditions to the closing of the Merger have been satisfied or waived, as applicable, or shall then be capable of being satisfied (except for the conditions relating to receipt of the required governmental and regulatory consents and approvals, the absence of any law or judgment in effect that prevents or prohibits the closing of the Merger or makes the closing of the Merger illegal or the absence of a Burdensome Condition), either Avista Corporation or the Corporation may extend the End Date to a date that is not later than six months after the End Date; provided, further that neither Avista Corporation or the Corporation may terminate the Merger Agreement if it (or, in the case of the Corporation, US Parent or Merger Sub) is in breach of the Merger Agreement and such breach has primarily caused the failure to satisfy the conditions to the obligations of the terminating party to consummate the Merger prior to the End Date or the failure of the closing of the Merger to have occurred by the End Date.

If either Avista Corporation or the Corporation terminates the Merger Agreement pursuant to the above clause (i) and, at the time of such termination:

(1) the governmental and regulatory consents and approvals required to be obtained by the Corporation, US Parent, Merger Sub and Avista Corporation have not been obtained, or any law or judgment is in effect that prevents or prohibits the consummation of the Merger or makes the consummation of the Merger illegal (but only if the applicable law or judgment giving rise to such termination arises in connection with the required governmental and regulatory consents and approvals), and at the time of such termination, the Avista Shareholder Approval has been obtained and the other closing conditions for the benefit of the Corporation (other than the receipt of the Avista Corporation officer's certificate and the absence of a Burdensome Condition) have been satisfied or waived (except for any conditions that have not been satisfied as a result of a breach of the Merger Agreement by the Corporation, US Parent or Merger Sub of its respective obligations), the Corporation will pay or cause to be paid to Avista Corporation a fee of US$103,000,000 (the "**Corporation Termination Fee**") in cash; or

(2) a Takeover Proposal was publicly disclosed or made to Avista Corporation and not publicly withdrawn prior to the date of termination and within twelve months of such termination, Avista Corporation enters into an agreement with respect to a competing transaction or consummates a Takeover Proposal, Avista Corporation will pay or cause to be paid to the Corporation a fee of US$103,000,000 (the "**Avista Termination Fee**") in cash.

(ii) any law or judgment (each, a "**Restraint**") is in effect that prevents, makes illegal or prohibits the consummation of the Merger, and, in the case of any judgment, shall have become final and non-appealable; provided, however that the right to terminate the Merger Agreement pursuant to this clause shall not be available to Avista Corporation or the Corporation if the issuance of such a final, non-appealable Restraint was primarily due to a breach by such party of any of its covenants or agreements under the Merger Agreement, including any failure to obtain the governmental and regulatory consents and approvals. If Avista Corporation or the Corporation terminates the Merger Agreement pursuant to this clause (but only if the applicable Restraint giving rise to such termination arises in connection with the governmental and regulatory consents and approvals), and at the time of any such termination, the Avista Shareholder Approval has been obtained and the other conditions of the closing for the benefit of the Corporation (other than the receipt of the Avista Corporation officer's certificate and the absence of a Burdensome Condition) have been satisfied or waived (except for any conditions that have not been satisfied as a result of a breach of the Merger Agreement by the Corporation, US Parent or Merger Sub of its respective obligations), the Corporation will pay or cause to be paid to Avista Corporation the Corporation Termination Fee in cash; or

(iii) the Avista Shareholder Approval is not obtained at a duly convened meeting of Avista Corporation's shareholders (the "**Avista Shareholders Meeting**") (including any adjournments or postponements thereof). If either Avista Corporation or the Corporation terminates the Merger Agreement pursuant to this clause and (A) a Takeover Proposal was publicly disclosed or made to Avista Corporation and not publicly withdrawn prior to the date of the Avista Shareholders Meeting and (B) within twelve months of such termination, Avista Corporation enters into an agreement with respect to a competing transaction or consummates a Takeover Proposal, Avista Corporation will pay or cause to be paid to the Corporation the Avista Termination Fee in cash.

Moreover, the Merger Agreement may be terminated by Avista Corporation if:

(i) the Corporation, US Parent or Merger Sub has breached or failed to perform any of its respective representations, warranties, covenants or agreements set forth in the Merger Agreement, which breach or failure to perform (A) would give rise to the failure of one of the closing conditions for the benefit of Avista Corporation and (B) cannot be cured by the Corporation, US Parent or Merger Sub by the End Date or, if capable of being cured, has not have cured within 30 days following receipt of written notice from Avista Corporation stating Avista Corporation's intention to terminate the Merger Agreement pursuant to this clause and the basis for such termination; provided that Avista Corporation will not have the right to terminate the Merger Agreement pursuant to this clause if Avista Corporation is then in material breach of the Merger Agreement. If Avista Corporation terminates the Merger Agreement pursuant to this clause because of a failure by the Corporation, US Parent or Merger Sub to comply with their obligations with respect to obtaining the governmental and regulatory consents and approvals; provided that, at the time of any such termination, the Avista Shareholder Approval has been obtained and the other conditions of the closing for the benefit of the Corporation (other than the receipt of the Avista Corporation officer's certificate and the absence of a Burdensome Condition) have been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach of the Merger Agreement by the Corporation, US Parent or Merger Sub of its respective obligations), the Corporation will pay or cause to be paid to Avista Corporation the Corporation Termination Fee in cash; or

(ii) prior to the receipt of the Avista Shareholder Approval, the board of directors of Avista Corporation (or a duly authorized committee thereof) has effected an Adverse Recommendation Change with respect to a Superior Proposal and has approved, and substantially concurrently with such termination, has entered into an agreement with respect to a competing transaction with respect to such Superior Proposal; provided that such termination will not be effective and Avista Corporation will not enter into any such an agreement with respect to a competing transaction, unless Avista Corporation has paid the Avista Termination Fee to the Corporation or causes the Avista Termination Fee to be paid to the Corporation substantially concurrently with such termination. If Avista Corporation terminates the Merger Agreement pursuant to this clause, Avista Corporation will pay or cause to be paid, to the Corporation the Avista Termination Fee.

Furthermore, the Merger Agreement may be terminated by the Corporation if:

(i) the board of directors of Avista Corporation (or a duly authorized committee thereof) has effected an Adverse Recommendation Change; provided that the Corporation will not have the right to such termination if the Avista Shareholder Approval has been obtained. If the Corporation terminates the Merger Agreement pursuant to this clause, Avista Corporation will pay or cause to be paid the Avista Termination Fee; or

(ii) Avista Corporation has breached or failed to perform any of its representations, warranties, covenants or agreements set forth in the Merger Agreement, which breach or failure to perform (A) would give rise to the failure of a condition to certain closing conditions for the benefit of the Corporation, US Parent or Merger Sub, respectively, and (B) cannot be cured by Avista Corporation by the End Date or, if capable of being cured, has not been cured within 30 days following receipt of written notice from the Corporation stating the Corporation's intention to terminate the Merger Agreement pursuant to this clause and the basis for such termination; provided that the Corporation will not have the right to such termination if the Corporation, US Parent or Merger Sub is then in material breach of the Merger Agreement. If the Corporation terminates the Merger Agreement pursuant to this clause (solely with respect to a breach or failure to perform a covenant), a Takeover Proposal was publicly disclosed or made to Avista Corporation and not publicly withdrawn prior to the date of termination and within twelve months of such termination, Avista Corporation enters into an agreement with respect to a competing transaction or consummates a Takeover Proposal, Avista Corporation will pay or cause to be paid to the Corporation the Avista Termination Fee.

Payment of Fees and Effect on Termination

Neither Avista Corporation nor the Corporation shall be required to pay the Avista Termination Fee or the Corporation Termination Fee, respectively, on more than one occasion.

Moreover, Avista Corporation, on the one hand, and the Corporation, US Sub and Merger Sub, on the other hand, agree that payment of the Avista Termination Fee and the Corporation Termination Fee, as applicable, shall not constitute a penalty, but rather will constitute liquidated damages. If Avista Corporation fails to pay the Avista Termination Fee and the Corporation, in order to obtain such payment, commences a claim that results in a judgment against Avista Corporation, Avista Corporation will pay to the Corporation, in addition to the Avista Termination Fee, the Corporation's costs and expenses (including reasonable attorneys' fees) in connection with such claim, along with interest from the date such payment was required until the date of payment. If the Corporation fails to pay the Corporation Termination Fee and Avista Corporation, in order to obtain such payment, commences a claim that results in a judgment against the Corporation, the Corporation will pay to Avista Corporation, in addition to the Corporation Termination Fee, Avista Corporation's costs and expenses (including reasonable attorneys' fees) in connection with such claim, along with interest from the date such payment was required until the date of payment.

Furthermore, upon payment by Avista Corporation of the Avista Termination Fee to the Corporation, including any costs pursuant to the above paragraph, Avista Corporation will have no further liability to the Corporation, US Parent or Merger Sub. Upon payment by the Corporation of the Corporation Termination Fee to Avista Corporation, including any costs pursuant to the above paragraph, the Corporation, US Parent and Merger Sub will have no further liability to Avista Corporation.

FINANCING THE MERGER

The cash purchase price of the Merger and the Merger-Related Expenses will be financed at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and the final instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Operating Credit Facility; and; (iv) existing cash on hand and other sources available to the Corporation.

Prior to the closing of the Merger, Hydro One Limited intends to use the net proceeds of the first instalment under the Offering, which are expected to be $441,700,000 (assuming no exercise of the Over-Allotment Option), to repay borrowings under the Operating Credit Facility or its subsidiaries' existing revolving credit facilities or other existing indebtedness (such indebtedness having been incurred for general corporate purposes), or for other general corporate purposes, including investing in short-term interest bearing U.S. dollar securities with investment grade counterparties and in Hydro One Limited's wholly-owned subsidiaries. In the event that the net proceeds of the first instalment under the Offering are used to reduce outstanding indebtedness or for other general corporate purposes, Hydro One Limited will maintain readily available capacity on its revolving credit facilities (on a consolidated basis), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment under the Offering. Upon the closing of the Merger, Hydro One Limited intends to use the net proceeds of the final instalment under the Offering, which are expected to be $909,300,000 (assuming no exercise of the Over-Allotment Option), to finance, directly or indirectly, together with the net proceeds of the first instalment under the Offering to the extent available, part of the purchase price payable for the Merger and for other Merger-Related Expenses.

Hydro One Limited currently intends to fund the remainder of the purchase price for the Merger with a combination of bond or other debt financings, denominated principally in U.S. dollars in order to provide a significant natural currency hedge, drawdowns on the Operating Credit Facility and cash on hand.

Hydro One Limited's overall financing plan in respect of the Merger is structured and targeted to maintain Hydro One Limited's and Avista Corporation's strong investment grade status. For additional information on the proposed financing plan for the Merger, see page A-8 of the Investor Presentation attached as Appendix A to this Prospectus.

See "Risk Factors" for a discussion of certain risks relating to the financing of the Merger.

CAPITALIZATION

Upon completion of the Offering, the closing of the Merger and assuming the payment of the final instalment and the conversion of all of the Debentures into Common Shares (based on the conversion price of $21.40 per Common Share), the Corporation will have, on a *pro forma* basis, an aggregate of approximately 660,420,561 Common Shares outstanding (assuming no exercise of the Over-Allotment Option and based on the 595,000,000 Common Shares issued and outstanding on March 31, 2017), or approximately 666,962,617 Common Shares if the Over-Allotment Option is exercised in full and based on the 595,000,000 Common Shares issued and outstanding on March 31, 2017.

The following table sets out the consolidated capitalization of the Corporation as at March 31, 2017 and on a *pro forma* basis, as of such date after giving effect to (i) the net proceeds of the Offering (including the payment of both the first instalment and final instalment), assuming no exercise of the Over-Allotment Option and determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the anticipated net proceeds of subsequent U.S. dollar bond or other debt offerings to fund the balance of the purchase price, (iii) the Merger, including the assumption of approximately US$1.9 billion of Avista Corporation's consolidated debt, (iv) the conversion of the Debentures into Common Shares and (v) the changes in Common Shares and long-term debt from April 1, 2017 up to and including July 31, 2017. See "Changes in Share and Loan Capital Structure" and "Financing the Merger". The financial information set out below has been compiled based on financial statements prepared in accordance with U.S. GAAP. See "Index to Financial Statements" and in particular, the *pro forma* financial statements beginning on page F-94 of this Prospectus.

	As at March 31, 2017 (unaudited)	***Pro forma* as at March 31, 2017 (unaudited)**(1)
	(in millions of $ dollars)	
Total Debt(2)	11,133	17,098
Shareholders' equity		
Securities offered hereby	-	1,351(5)

Common Shares[3]	5,623	5,623
Series 1 Preferred Shares	418	418
Additional contributed surplus	40	40
Accumulated other comprehensive loss	(7)	(7)
Retained earnings	3,992	3,798
Total capitalization	21,199	28,321

(1) After giving effect to (i) the net proceeds of the Offering (including the payment of both the first instalment and final instalment), assuming no exercise of the Over-Allotment Option and determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the anticipated net proceeds of subsequent U.S. dollar bond or other debt offerings to fund the balance of the purchase price, (iii) the Merger, including the assumption of approximately US$1.9 billion of Avista Corporation's consolidated debt, and (iv) the conversion of the Debentures into Common Shares. See "Changes in Share and Loan Capital Structure", "Financing the Merger" and "Index to Financial Statements".

(2) Includes long-term debt (including the current portion and short-term borrowings).

(3) Does not include the Common Shares issuable upon the conversion of the Debentures, which are included as "Securities offered hereby".

(4) Excludes non-controlling interests.

(5) Excluding approximately $13 million in deferred tax.

EARNINGS COVERAGE RATIOS

The Corporation's interest requirements on all of its outstanding debt securities after giving effect to the issue of the Debentures distributed hereunder (assuming no exercise of the Over-Allotment Option and the issuance of such Debentures at the beginning of such period) amounted to $449 million and $456 million for the 12 months ended December 31, 2016 and the 12 months ended March 31, 2017, respectively. The Corporation's earnings before interest and income tax for the 12 months ended December 31, 2016 and 12 months ended March 31, 2017 were $1.278 billion and $1.237 billion, respectively, which is 2.8 times and 2.7 times, respectively, the Corporation's aggregate interest requirements for the periods.

The earnings coverage ratios of the Corporation calculated on a *pro forma* basis after giving effect to the Merger (including the assumption of approximately US$1.9 billion of Avista Corporation's consolidated debt), the conversion of the Debentures into Common Shares (assuming no exercise of the Over-Allotment Option), and the anticipated net proceeds of subsequent U.S. dollar bond or other debt offerings to fund the balance of the purchase price (in each case as if they had occurred at the beginning of such period), are calculated as follows: (i) the Corporation's interest requirements on all of its outstanding debt securities amounted to $639 million and $167 million for each of the 12 months ended December 31, 2016 and the three months ended March 31, 2017, respectively; and (ii) the Corporation's earnings before interest and income tax for the 12 months ended December 31, 2016 and three months ended March 31, 2017 were $1.674 billion and $460 million, respectively, which is 2.6 times and 2.8 times, respectively, the Corporation's aggregate interest requirements for the periods.

CHANGES IN SHARE AND LOAN CAPITAL STRUCTURE

There have been no material changes in Hydro One Limited's share and loan capital, on a consolidated basis, since the date of the Interim Financial Statements. As a result of the Offering, after giving effect to the assumed conversion of the Debentures into Common Shares, shareholders' equity in the Corporation will increase by approximately $1.351 billion (assuming no exercise of the Over-Allotment Option).

PRIOR SALES

The following table sets out the issuance of Common Shares and securities convertible into or exchangeable for Common Shares that occurred in the 12-month period before the date of this Prospectus:

Date of Issue	Securities[(1)(2)]	Price per Security	Number of Common Shares Issuable or Issued, as applicable
August 15, 2016	RSUs	$25.49	1,690
August 15, 2016	PSUs	$25.49	3,140
September 1, 2016	RSUs	$26.19	17,180
September 1, 2016	PSUs	$26.19	17,180
September 7, 2016	RSUs	$26.49	16,990
September 7, 2016	PSUs	$26.49	16,990
September 9, 2016	RSUs[(3)]	$25.98	45,130
September 9, 2016	PSUs	$25.98	45,130
September 12, 2016	RSUs	$25.75	20,830
September 12, 2016	PSUs	$25.75	20,830
November 14, 2016	RSUs	$22.65	8,030
November 14, 2016	PSUs	$22.65	8,030
March 31, 2017	RSUs	$24.25	218,950
March 31, 2017	PSUs	$24.25	267,450
April 1, 2017	Common Shares[(4)]	$20.50	371,611
May 31, 2017	Common Shares[(5)]	$25.98	13,714
July 21, 2017	Common Shares[(6)]	$24.31	1,274

Notes:

(1) Except as noted in footnote (3) below, each RSU granted in 2016 and 2017 vests in full on December 31, 2018 and December 31, 2019, respectively, assuming the individual has remained employed by Hydro One Limited or its subsidiaries through such date. Each vested RSU entitles the holder thereof to one Common Share. RSUs also earn dividend equivalents as dividends are paid on the Common Shares. Price per security represents the grant date price of the RSUs.

(2) Each PSU granted in 2016 and 2017 vests on December 31, 2018 and December 31, 2019, respectively, subject to achieving certain performance thresholds for the three-year average earnings per share for the period from (i) January 1, 2016 to December 31, 2018, in the case of 2016 grants and (ii) January 1, 2017 to December 31, 2019, in the case of 2017 grants, and provided further that the dividend rate is not decreased during the period. In the event the dividend rate is decreased during the period, no PSUs will vest regardless of whether the performance thresholds are met. In respect of the performance thresholds, below a certain performance threshold, no PSUs will vest. At the target performance threshold (assuming the dividend rate is not reduced during the period), the PSUs vest at the target level of 100% and will entitle the holder thereof to one Common Share for each PSU granted. At or above the maximum performance threshold (assuming the dividend rate is not reduced during the period), the PSUs vest at the maximum level of 200% and will entitle the holder thereof to two Common Shares for each PSU granted. Between performance thresholds (assuming the dividend rate is not reduced during the period), PSUs will vest on an interpolated basis. PSUs also earn dividend equivalents as dividends are paid on the Common Shares. The number of Common Shares issuable pursuant to the PSUs assumes the PSUs vest at 100% of their target. Price per security represents the grant date price of the PSUs.

(3) 13,470 of these RSUs vest on May 31, 2018. 13,470 of these RSUs vested on May 31, 2017 and 13,714 Common Shares (including related accrued dividend equivalents) were issued on that date. See footnote (5).

(4) Upon terms and conditions previously agreed to, Hydro One Limited issued these Common Shares to eligible employees at the initial public offering price of the Common Shares in accordance with the provisions of the PWU Share Grant Plan.

(5) A total of 13,714 Common Shares were issued from treasury on the vesting of 13,470 RSUs and 244 related accrued dividend equivalents on May 31, 2017. See footnote (3). Price per security represents the grant date price of the RSUs.

(6) A total of 1,274 Common Shares were issued from treasury on July 21, 2017 from the vesting of 610 RSUs (and 27 related accrued dividend equivalents) and 610 PSUs (and 27 related accrued dividend equivalents) granted on March 31, 2016 arising from the death of the holder of the RSUs and PSUs. Price per security represents the grant date price of the RSUs and PSUs.

TRADING PRICES AND VOLUMES

The outstanding Common Shares are traded on the TSX under the trading symbol "H". The following table sets forth the high and low price for, and the volume of trading in, the Common Shares for the periods indicated, based on information obtained from the TSX.

	Price ($)		
Month	**High**	**Low**	**Trading Volume**
2016			
August	26.48	25.10	7,138,631
September	26.54	25.36	7,031,417
October	26.02	24.02	6,765,511
November	24.58	22.06	11,932,522
December	23.65	22.59	9,719,103
2017			
January	24.49	23.49	8,368,116
February	24.17	23.22	8,477,586
March	24.28	23.04	11,764,543
April	24.66	23.84	6,292,356
May	24.15	22.63	42,296,289
June	23.98	22.73	19,011,705
July	23.25	21.32	17,158,684

DESCRIPTION OF COMMON SHARES

Hydro One Limited's authorized share capital consists of an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series, of which 595,386,599 Common Shares, 16,720,000 Series 1 preferred shares and no Series 2 preferred shares are issued and outstanding as of the date of this Prospectus.

Holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders, except meetings at which only the holders of another class or series of shares are entitled to vote separately as a class or series, and holders of Common Shares are entitled to one vote per share at all such meetings of shareholders. Hydro One Limited's Common Shares are not redeemable or retractable. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 Preferred Shares and Series 2 Preferred Shares, holders of Common Shares are entitled to receive dividends if, as, and when declared by the Board of Directors. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 Preferred Shares and Series 2 Preferred Shares, holders of Common Shares are also entitled to receive the remaining assets of Hydro One Limited upon its liquidation, dissolution or winding-up or other distribution of Hydro One Limited's assets for the purposes of winding-up its affairs.

Voting securities of Hydro One Limited, which include the Common Shares, are subject to share ownership restrictions under the *Electricity Act, 1998* (Ontario). The share ownership restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds voting securities of Hydro One Limited solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, may beneficially own or exercise control or direction over more than 10% of any class or series of voting securities of Hydro One Limited. The articles of Hydro One Limited provide for comprehensive enforcement mechanisms that are applicable in the event of a contravention of the share ownership requirements. **A potential purchaser of Debentures represented by Instalment Receipts should not subscribe for a number of such Debentures in this Offering that would, upon conversion of such Debentures into Common Shares, cause such purchaser to violate this prohibition.**

DETAILS OF THE OFFERING

The Offering consists of $1,400,000,000 aggregate principal amount of Debentures represented by Instalment Receipts at a price of $1,000 per Debenture, which are being sold by the Selling Debentureholder on an instalment basis. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable following notification to holders of Instalment Receipts (the "**Final Instalment Notice**") that the Corporation has received all regulatory and government approvals required to finalize the Merger and Hydro One Limited, US Parent, Merger Sub and Avista Corporation have fulfilled or waived all other outstanding conditions precedent to closing the Merger, other than those which by their nature cannot be satisfied until the closing of the Merger, in each case as set out in the Merger Agreement (collectively, the "**Approval Conditions**"). See "The Merger Agreement". The Final Instalment Notice, which must be given by no later than April 30, 2019, will establish a date for payment of the final instalment (the "**Final Instalment Date**"), which shall not be less than 15 days nor more than 90 days following the date of such notice. Payment of the final instalment in full must be received by the Custodian (as defined in this Prospectus) by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date. Holders should make arrangements with the securities broker, trust company or other financial institution through which they hold Instalment Receipts to pay the final instalment sufficiently in advance of the Final Instalment Date to ensure that such payment is received by the Custodian prior to this deadline.

The Selling Debentureholder

The Selling Debentureholder is a direct wholly-owned subsidiary of Hydro One Limited organized under the OBCA. The Selling Debentureholder will acquire (both of record and beneficially) the Debentures offered pursuant to this Prospectus from Hydro One Limited for the purpose of participating in the Offering.

If the Over-Allotment Option is exercised by the Underwriters, the Selling Debentureholder will acquire the Debentures purchased in the Over-Allotment Option from Hydro One Limited and will sell them to the Underwriters on the terms and conditions set out in the Underwriting Agreement.

Waiver of Pre-Emptive Right by Province

The Province waived its pre-emptive right to participate in the Offering under the Governance Agreement. In consideration of granting the waiver, the Corporation agreed that until July 19, 2018: (i) the Corporation shall not issue Common Shares pursuant to the Corporation's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the Common Shares outstanding as of July 19, 2017; and (ii) the Corporation shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Instalment Receipts

The following is a summary of the material attributes and characteristics of the Instalment Receipts representing Debentures and the rights and obligations of holders thereof. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the instalment receipt and pledge agreement (the "**Instalment Receipt Agreement**"), to be dated as of the Closing Date, among the Corporation, the Selling Debentureholder, the Underwriters and Computershare Trust Company of Canada in its capacity as custodian and security agent (the "**Custodian**"). Copies of the Instalment Receipt Agreement will be available for inspection at the principal offices of the Custodian in Toronto, Ontario. A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Instalment Receipt Agreement, a copy of which will also be available on the Corporation's SEDAR profile at www.sedar.com on or about the Closing Date.

Holders of Instalment Receipts will be bound by the terms of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that legal title to the Debentures offered hereby will be held by the Custodian following payment of the first instalment and until the Final Instalment Date, provided that legal title will be retained if the final instalment has not been fully paid to the Custodian for the benefit of the Selling Debentureholder on or before the Final Instalment Date (and in no case later than 3:30 p.m. (Toronto time) on the Final Instalment Date). The Debentures offered hereby will be pledged to the Selling Debentureholder by the Underwriters (for and on behalf of the purchasers of Debentures represented by Instalment Receipts under the Offering) at the closing of the Offering and the physical certificate or certificates representing the Debentures will be held in the possession of the Custodian, as security agent, on behalf of the Selling Debentureholder, subject to the terms of the Instalment Receipt Agreement.

Prior to payment of the final instalment, beneficial ownership of Debentures will be represented by Instalment Receipts. An Instalment Receipt will evidence, among other things, (i) the fact that the first instalment has been paid in respect of the Debenture represented thereby and (ii) the right of a holder thereof, subject to compliance with the provisions of the Instalment Receipt Agreement, (x) to have the pledge of the Debentures released following the Final Instalment Date provided that payment in full of the final instalment with respect to such Debentures has been received by the Custodian on or prior to such date or (y) if the Debentures are redeemed by the Corporation prior to payment of the final instalment, to receive (after the Custodian pays the final instalment to the Selling Debentureholder on behalf of the holder) $333 per underlying Debenture plus accrued and unpaid interest on such Debenture up to but excluding the redemption date. A holder of an Instalment Receipt will be deemed to have assumed the obligation to pay the final instalment on or before the Final Instalment Date and to have acquired beneficial ownership of the Debenture represented by the Instalment Receipt, subject to the pledge of such Debenture which secures such obligations subject to the terms of the Instalment Receipt Agreement. Subject to the terms of the Instalment Receipt Agreement, a holder of an Instalment Receipt will be further deemed to agree that the foregoing pledge will remain in effect and be binding and effective notwithstanding any transfer of or other dealings with the Instalment Receipt and the rights evidenced or arising thereby.

The Corporation shall as soon as practicable following satisfaction of the Approval Conditions (but no later than April 30, 2019) cause a Final Instalment Notice to be given to holders of Debentures represented by Instalment Receipts (i) confirming that all Approval Conditions have been fulfilled to the satisfaction of the Corporation, (ii) setting the Final Instalment Date (which shall not be less than 15 days nor more than 90 days following the date that such notice is first given) and (iii) advising holders of their ability to exercise the conversion privilege with respect to Debentures represented by their Instalment Receipts concurrently with the payment of the final instalment. See "Details of the Offering – Debentures – Conversion Right". The Selling Debentureholder shall also cause to be issued a press release containing particulars of the Final Instalment Notice. Payment of the final instalment is required regardless of whether a holder receives the Final Instalment Notice, directly or indirectly. The Final Instalment Date may occur up to 90 days following April 30, 2019.

A holder of an Instalment Receipt will be entitled to make payment, in accordance with the provisions of the Instalment Receipt Agreement, of the final instalment at any time following receipt of the Final Instalment Notice and prior to 3:30 p.m. (Toronto time) on the Final Instalment Date. **A holder of Instalment Receipts that fails to pay the final instalment in full by 3:30 p.m. (Toronto time) on the Final Instalment Date (a "Defaulting Holder") will have no further right to pay the final instalment and all rights and privileges of the Defaulting Holder described below under "– Rights and Privileges" shall immediately cease (unless otherwise waived by the Selling Debentureholder).**

Subject to compliance with the provisions of the Instalment Receipt Agreement and timely payment of the final instalment, the Custodian will, as soon as practicable on or after the Final Instalment Date, discharge and release the pledge of the Debentures represented by such Instalment Receipts. At that time, the Debentures (or the Common Shares into which the Debentures may be converted) will be held through the facilities of CDS, and the holder will receive only a customer confirmation of purchase of the Debentures (or, if the conversion privilege is exercised, the underlying Common Shares) from the holder's CDS Participant.

The Instalment Receipts representing the Debentures will be issued in "book-entry only" form and must be purchased or transferred through a CDS Participant. The Corporation will cause a global certificate or certificates representing any newly issued Instalment Receipts to be delivered to, and registered in the name of, CDS or its nominee. All rights and obligations of holders of Instalment Receipts must be exercised or performed through, and all notices, payments or other property to which such holders are entitled or obligated will be made or delivered by the holder holding such Instalment Receipts through CDS or the CDS Participants in accordance with the rules and procedures applicable to CDS and such CDS Participants. Each person who acquires Instalment Receipts will only receive a customer confirmation of purchase from the CDS Participant from or through which the Instalment Receipts representing the Debentures are acquired in accordance with the practices and procedures of that registered dealer. The practices of CDS Participants may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book-entry accounts for its CDS Participants having interests in Instalment Receipts. See "– Book-Entry Only System". Because payment of the final instalment will be made by holders of Instalment Receipts through CDS and CDS Participants, it is strongly advised that holders make arrangements with the securities broker, trust company or other financial institution through which they hold Instalment Receipts to pay their final instalment sufficiently in advance of the Final Instalment Date to ensure that such payment is received by the Custodian by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date.

Transfer of Instalment Receipts

The TSX has conditionally approved the listing of the Instalment Receipts on the facilities of the TSX, subject to the fulfillment of all of the requirements of the TSX. Once listed, it is anticipated that holders will be able to transfer Instalment Receipts through the facilities of the TSX until the close of trading on the trading day immediately preceding the Final Instalment Date, following which Instalment Receipts will stop trading on the TSX. Upon a transfer of an Instalment Receipt, the transferee will acquire the transferor's rights, subject to the pledge of the Debentures in favour of the Selling Debentureholder, and become subject to the obligations of a holder of Instalment Receipts under the Instalment Receipt Agreement, including the assumption by the transferee of the obligation to pay the final instalment on or before the Final Instalment Date. No transfer of an Instalment Receipt after the Final Instalment Date will be accepted (except where an intermediary holds Instalment Receipts on behalf of a non-registered holder and such non-registered holder has failed to pay the final instalment when due, or with the express consent of the Selling Debentureholder).

Liability of Instalment Receipt Holders

Pursuant to the Instalment Receipt Agreement, the Underwriters will pledge (for and on behalf of the purchasers of Debentures represented by Instalment Receipts under the Offering) the Debentures purchased on an instalment basis to secure payment of the final instalment. If payment of the final instalment is not duly received by the Custodian from a holder of Instalment Receipts when due, the Instalment Receipt Agreement will provide that (except as set out below) any Debenture then remaining pledged under the Instalment Receipt Agreement may, at the option of the Selling Debentureholder, subject to complying with applicable law, be forfeited to the Selling Debentureholder in full satisfaction of the obligations of such holder of Instalment Receipts secured thereby. The Instalment Receipt Agreement will further provide that the Selling Debentureholder may, alternatively, direct the Custodian to sell the Debentures in respect of which payment of the final instalment was not duly received, in accordance with the requirements of applicable law and of the Instalment Receipt Agreement, and remit to the Defaulting Holder of Instalment Receipts its pro rata portion of the proceeds of sale after deducting therefrom the amount of the remaining unpaid final instalment, the amount of any applicable withholding taxes and the Defaulting Holder's pro rata portion of the costs of sale (such costs not to exceed $25 per $1,000 principal amount of Debentures). The Instalment Receipt Agreement will provide that the foregoing shall not limit any other remedies available to the Selling Debentureholder against such Defaulting Holder of the Instalment Receipt in the event proceeds of such sale are insufficient to cover the amount of the final instalment and the costs of sale and accordingly, such holder shall in such circumstances remain liable to the Selling Debentureholder for any such deficiency.

Rights and Privileges

Under the Instalment Receipt Agreement, holders of Instalment Receipts will have the same rights and privileges, and will be subject to the same limitations, as holders of Debentures pursuant to the Indenture (as defined in this Prospectus). In particular, holders of Instalment Receipts will be entitled under arrangements through the Custodian, in the manner set forth in the Instalment Receipt Agreement, to (i) receive interest on the Debentures represented by Instalment Receipts up to and including the Final Instalment Date, after which the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures, (ii) receive the Make-Whole Payment in respect of the Debentures represented thereby if the Final Instalment Date occurs prior to the first anniversary of the Closing Date and provided that a holder of Debentures represented by Instalment Receipts has paid the final instalment on or prior to the Final Instalment Date and (iii) exercise the votes attached to the Debentures represented by such Instalment Receipts. In the event that the Corporation issues (including on liquidation, dissolution or winding-up) to the holders of Debentures any securities, or options, rights or warrants to purchase any securities, or any securities convertible into or exchangeable for securities, or other property or assets of like nature, the Custodian will, as promptly as commercially reasonable sell such securities, options, rights, warrants, evidences of indebtedness, property or assets and remit pro rata to the holders of Instalment Receipts, the proceeds of sale net of the Custodian's costs of disposition, subject to withholding tax requirements.

Redemption of Debentures and Cancellation of Instalment Receipts

In the event that Debentures are required to be redeemed by the Corporation prior to the Final Instalment Date, the Corporation shall, in respect of each Instalment Receipt outstanding on the date of such redemption, pay (or cause to be paid) to the Selling Debentureholder, on behalf of the holder of an Instalment Receipt, an amount equal to the final instalment and pay the balance plus any accrued and unpaid interest to the holder. Payment of such redemption price will be made on the date that the Debentures are redeemed by the Corporation.

Modification

Apart from changes which do not adversely affect in any material respect the holders of Instalment Receipts as a group (which may be made without the consent of such holders), the Instalment Receipt Agreement may not be amended without the affirmative vote of the holders of Instalment Receipts entitled to not less than two-thirds of the principal amount of Debentures represented by Instalment Receipts which are represented and voted at a meeting duly called for the purpose or rendered by instruments in writing signed by the holders of Instalment Receipts representing not less than two-thirds of the principal amount of the Debentures.

General

The Custodian may require holders of Instalment Receipts from time to time to furnish such information and documents as may be necessary or appropriate to comply with any fiscal or other laws or regulations relating to the Debentures or to rights and obligations represented by Instalment Receipts. The Custodian shall not be responsible for any taxes, duties, governmental charges or expenses which are or may become payable in respect of the Debentures or Instalment Receipts. In this regard, the Custodian shall be entitled to deduct or withhold from any payment or other distribution required or contemplated by the Instalment Receipt Agreement the appropriate amount of money or property, or to require holders of Instalment Receipts to make any required payments, and to withhold delivery of certificates representing the Debentures until satisfactory provision for payment is made, in respect of any non-resident Canadian withholding taxes or other taxes, duties, governmental charges or expenses required by applicable law to be withheld or paid.

Holders of Instalment Receipts will not be liable for charges and expenses of the Custodian except for any taxes, duties, governmental charges or expenses which may be payable as described above.

Book-Entry Only System

Registration of interests in and transfers of Instalment Receipts will be made only through the book-entry only system of CDS (the "**Book-Entry Only System**"). Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. Upon purchase of any Instalment Receipts representing Debentures, the Corporation understands that the holder of Instalment Receipts will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Instalment Receipts are purchased. References in this Prospectus to a holder of Instalment Receipts mean, unless the context otherwise requires, the owner of the beneficial interest in such Instalment Receipts.

The ability of a beneficial owner of Instalment Receipts to pledge such Instalment Receipts or otherwise take action with respect to such beneficial holder's interest in such Instalment Receipts (other than through a CDS Participant) may be limited due to the lack of a physical certificate.

The Selling Debentureholder has the option to terminate registration of the Instalment Receipts through the Book-Entry Only System in which case certificates for the Instalment Receipts in fully registered form would be issued to holders of such Instalment Receipts.

Debentures

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the trust indenture (the "**Indenture**") to be dated on or about the Closing Date between the Corporation, as issuer, and Computershare Trust Company of Canada, as trustee (in such capacity, the "**Trustee**"). A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Indenture, a copy of which will be available on the Corporation's SEDAR profile at www.sedar.com on or about the Closing Date.

The Debentures will be issued to the Selling Debentureholder on the Closing Date as the initial series under the Indenture and in the aggregate principal amount of $1,400,000,000. In the event that the Over-Allotment Option is exercised, Hydro One Limited will issue additional Debentures of the same series under the Indenture.

The Debentures will be dated as of the Closing Date and will mature on the Maturity Date. The Debentures are issuable in denominations of $1,000 and integral multiples thereof and will bear interest at an annual rate of 4.00% per $1,000 principal amount of Debentures and will be payable quarterly in arrears in equal instalments (other than the first interest payment and, depending on the Final Instalment Date, the final interest payment) on the last day of December, March, June and September of each year (or the prior business day if the last day falls on a weekend or holiday) to and including the Final Instalment Date. The first interest payment in the amount of $15.78082 per $1,000 principal amount of Debentures will be made on December 29, 2017 and will include interest payable from and including the date of issue. Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures. A final interest payment will be made on the Final Instalment Date, will be equal to the unpaid interest accrued from the date of the last quarterly interest payment to and including the Final Instalment Date and will be computed on the basis of a 365-day year and the number of days elapsed in the period. On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures. Based on a first instalment of $333 per $1,000 principal amount of Debenture and assuming the Final Instalment Date occurs on or after the first anniversary of the Closing Date, the effective annual yield to and including the Final Instalment Date will be 12.0%, and the effective yield thereafter will be 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, the Make-Whole Payment, being an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date. No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date. No Make-Whole Payment will be made in the event that the Corporation redeems the Debentures.

The Debentures will be direct obligations of Hydro One Limited and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Corporation as described below under "– Subordination". The Indenture does not restrict the Corporation from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

Payment Upon Maturity

On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted into Common Shares and remaining outstanding, in cash, provided that the Corporation may, at its option and without prior notice, satisfy the obligation to pay all or a portion of the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the Market Price.

Conversion Right

At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares on or at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date. The Conversion Price will be $21.40 per Common Share, being a conversion rate of 46.7290 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. No adjustment will be made for cash dividends on Common Shares issuable upon conversion or for accrued and unpaid interest, which will be paid by the Corporation in cash. A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. The Corporation reserves the right to not issue Common Shares to a holder upon conversion of the Debentures in the event the Corporation reasonably determines that issuing such Common Shares to such holder would result in such holder breaching the share ownership restrictions under the *Electricity Act, 1998* (Ontario) or be prohibited by the Corporation's articles.

Subject to the provisions thereof, the Indenture will provide for the adjustment of the Conversion Price in certain events including: (a) the distribution of Common Shares or securities convertible into Common Shares to holders of its Common Shares by way of stock dividend or otherwise, other than an issue of Common Shares to holders of outstanding Common Shares who have elected to receive dividends in stock in lieu of receiving cash dividends paid in the ordinary course; (b) the subdivision or consolidation of the outstanding Common Shares; (c) the issuance of rights or warrants to all holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than the Conversion Price; (d) the distribution to all holders of Common Shares of any securities or assets (other than cash dividends and dividends in Common Shares); or (e) if an issuer bid or exchange offer is made by the Corporation for its Common Shares. There will be no adjustment of the Conversion Price in respect of any event described herein if, with the prior regulatory approval and the approval of the TSX, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to such transaction. The Corporation will not be required to make adjustments in the Conversion Price unless the effect of such adjustment would change the Conversion Price by at least 1%, provided that any adjustment of less than 1% will be carried forward and taken into account in connection with any subsequent adjustment.

No fractional Common Shares will be issued on any conversion but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the Conversion Price of such fractional interest, provided that the Corporation shall not be required to make any cash payment of less than $10.00.

Redemption

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest (without any Make-Whole Payment) following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Merger Agreement in accordance with its terms; and (iii) May 1, 2019, if the Final Instalment Notice has not been given on or before April 30, 2019. Upon any such redemption, the redemption proceeds will be paid by the Corporation to the Custodian on behalf of the holders. The Custodian will pay the following for each $1,000 principal amount of Debentures: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Hydro One Limited has agreed that until such time as the Debentures have been redeemed or the Final Instalment Date has occurred, the Corporation will at all times hold short-term interest bearing U.S. dollar securities with investment grade counterparties, maintain readily available capacity under the Operating Credit Facility or the revolving credit facilities of its subsidiaries, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering and the exercise of the Over-Allotment Option, if applicable.

In addition, after the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to the Final Instalment Date.

Subordination

The Debentures will be direct unsecured obligations of Hydro One Limited. Payment of the principal of, interest on, the Make-Whole Payment, if any, and other amounts owing in respect of each Debenture will be subordinated in right of payment to any present or future senior unsubordinated indebtedness or obligation of the Corporation, whether or not contingent, for (i) moneys borrowed or raised by whatever means (including, without limitation, by means of commercial paper, bankers acceptances, debt instruments and any liability represented by bonds, debentures, notes or similar instruments), (ii) reimbursement obligations with respect to letters of credit; (iii) payment and guarantee obligations under or with respect to swap contracts, (iv) capital leases, (v) cash management obligations, (vi) the deferred purchase price of assets or services and (vii) any trade debts in effect at any time and from time to time (collectively, the "**Senior Indebtedness**"). Payment of the principal of, interest on, the Make-Whole Payment, if any, and other amounts owing in respect of each Debenture will rank pari passu with each other Debenture issued under the Indenture regardless of their actual date or terms of issue, and with all other present and future unsecured and subordinated indebtedness of Hydro One Limited, except as prescribed by law.

The Indenture does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. The Indenture provides that the Corporation shall not make any payment, and the holders of Debentures shall not be entitled to demand, accelerate, institute proceedings for the collection of, or receive any payment or benefit (including, without limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures (i) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; (ii) unless all payments of interest then due or payable on all Senior Indebtedness for borrowed money have been made; (iii) at any time when any amount is in arrears under any Senior Indebtedness or an event of default has occurred under Senior Indebtedness, and such a default or event of default is continuing, unless and until such Senior Indebtedness has been paid and satisfied in full or such default or event of default shall have been cured or waived in writing in accordance with the provisions of such Senior Indebtedness; or (iv) if the making of any such payment or the taking of any such action would create, including by the lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness unless and until such Senior Indebtedness has been satisfied in full or the making of any such payment or taking of any such action would no longer create, including by lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness.

In addition, the Trustee on behalf of the holders of Debentures may, at the request of the Corporation, enter into contractual subordination agreements with certain lenders of the Corporation with terms to the foregoing effect.

Events of Default

The Indenture will include the following events of default:

(a) failure to pay any principal or premium, if any, on the Debentures, when the same becomes due and payable whether on maturity, redemption, acceleration or otherwise, which default continues for a period of five business days;

(b) failure to pay any interest or Make-Whole Payment, if any, on the Debentures, which default continues for 45 days after the date when due;

(c) failure to deliver when due all cash and Common Shares deliverable upon conversion of the Debentures, which failure continues for 45 days;

(d) the Corporation's failure to perform or observe any other material term, covenant or agreement contained in the Debentures or contained in the Indenture for a period of 60 days after receipt of notice of default specifying such failure;

(e) default by the Corporation or any "material subsidiary" (as defined in the Indenture), with respect to any indebtedness (excluding amounts due to the holders of Debentures), where the aggregate principal amount of such indebtedness exceeds an amount equal to the greater of 2% of the consolidated net worth of the Corporation or $100,000,000 at such time and (i) if the default is a payment default, such default continues to exist for a period exceeding 60 days; provided that if the payment obligation to which the default relates is accelerated, then the default shall constitute an event of default immediately following such acceleration, and (ii) if the default is not a payment default, then as a result of the default and the passing of any applicable cure period, the maturity of the obligation is accelerated; provided that, in each case, if the default is cured prior to acceleration of the Debentures, then the event of default shall be deemed to have been cured; and

(f) certain events of bankruptcy, insolvency or reorganization affecting the Corporation.

If an event of default (other than the events listed in (f)) occurs and is continuing, either the Trustee or the holders of at least 25% in aggregate principal amount of the Debentures then outstanding may declare (by notice to the Corporation and the Trustee) the principal of the Debentures and any accrued and unpaid interest, if any, through the date of such declaration to be immediately due and payable. In the case of certain events of bankruptcy or insolvency, the principal amount of the Debentures together with any accrued but unpaid interest, if any, through the occurrence of such event shall automatically become and be immediately due and payable.

Modification

The rights of the holders of the Debentures may be modified. For that purpose, among others, the Indenture will contain certain provisions which will make binding on all holders of Debentures resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than two-thirds of the principal amount of the Debentures, or rendered by instruments in writing signed by the holders of not less than two-thirds of the principal amount of the Debentures then outstanding.

Certification and the Book-Entry Only System

Registration of interests in and transfers of Debentures represented by Instalment Receipts will be made only through the Book-Entry Only System. Debentures represented by Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. From the Closing Date to the Final Instalment Date, the Debentures will be issued in certificated and fully registered form in the name of Computershare Trust Company of Canada, in its capacity as security agent under the Instalment Receipt Agreement. Promptly following 3:30 p.m. (Toronto time) on the Final Instalment Date, provided due payment of the final instalment has been made in accordance with the terms of the Instalment Receipt Agreement, the Selling Debentureholder will cause the Custodian to deliver to CDS (i) a global certificate representing those Debentures not converted to Common Shares by exercise of the conversion right and (ii) Common Shares issued upon conversion of Debentures, in each case, to be registered in the name of CDS or its nominee. The Debentures will be represented by one or more global certificates. Thereafter, registration of interests in and transfers of the Debentures will be made only through the depository service of CDS and transfers of Common Shares will be effected electronically through the non-certificated inventory system administered by CDS.

Upon purchase of any Debentures through the Book-Entry Only System, the Corporation understands that the holder of Debentures will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Debentures are purchased. References in this Prospectus to a holder of Debentures mean, unless the context otherwise requires, the owner of the beneficial interest in such Debentures.

The Corporation will have the option to terminate registration of the Debentures through the Book-Entry Only System, in which case certificates for the Debentures in fully registered form would be issued to holders of such Debentures.

USE OF PROCEEDS

The net proceeds from the Offering (including both the first instalment and final instalment) will be, in the aggregate, $1,349,500,000 determined after deducting the Underwriters' fee and the estimated expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds will be, in the aggregate, $1,484,600,000.

Prior to the closing of the Merger, Hydro One Limited intends to use the net proceeds of the first instalment under the Offering, which are expected to be $441,700,000 (assuming no exercise of the Over-Allotment Option), to repay borrowings under the Operating Credit Facility or its subsidiaries' existing revolving credit facilities or other existing indebtedness (such indebtedness having been incurred for general corporate purposes), or for other general corporate purposes, including investing in short-term interest bearing U.S. dollar securities with investment grade counterparties and in Hydro One Limited's wholly-owned subsidiaries. In the event that the net proceeds of the first instalment under the Offering are used to reduce outstanding indebtedness or for other general corporate purposes, Hydro One Limited will maintain readily available capacity on its revolving credit facilities (on a consolidated basis), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment under the Offering. Upon the closing of the Merger, Hydro One Limited intends to use the net proceeds of the final instalment under the Offering, which are expected to be $909,300,000 (assuming no exercise of the Over-Allotment Option), to finance, directly or indirectly, together with the net proceeds of the first instalment under the Offering to the extent available, part of the purchase price payable for the Merger and for other Merger-Related Expenses. See "Relationship between Hydro One Limited, the Selling Debentureholder and Certain Underwriters" and "Financing the Merger".

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated July 25, 2017 (the "**Underwriting Agreement**") among Hydro One Limited, the Selling Debentureholder and the Underwriters, the Selling Debentureholder has agreed to sell, and the Underwriters have agreed to purchase, as principals, on the Closing Date, all but not less than all of the Debentures offered hereby on an instalment basis at a price of $1,000 per $1,000 principal amount of Debentures (the "**Offering Price**"). The Offering Price is payable in cash to the Selling Debentureholder on delivery as follows: the first instalment of $333 per $1,000 principal amount of Debenture is payable on the Closing Date against delivery; and the final instalment of $667 per $1,000 principal amount of Debenture is payable by the holders of Instalment Receipts on or before the Final Instalment Date. See "Details of the Offering".

The obligations of the Underwriters under the Underwriting Agreement are several and not joint or joint and several and may be terminated by them on the basis of certain stated events. Under the Underwriting Agreement, the obligations of any Underwriter may be terminated in their discretion if, at or prior to the Closing Date: (i) there should occur, be announced or be discovered any material change or any change in a material fact in relation to Hydro One Limited which, in the opinion of any of the Underwriters, acting reasonably, is expected to result in the purchasers of a material number of Debentures exercising their right under applicable Canadian securities laws to withdraw from their purchase of Debentures or would be expected to have a significant adverse effect on the market price or value of the Debentures, the Instalment Receipts, the Common Shares issuable upon conversion of the Debentures or any other securities of Hydro One Limited; (ii) there should develop, occur or come into effect or existence any event, action, state, condition or major financial occurrence of national or international consequence or there shall have occurred any outbreak or escalation of hostilities, declaration by Canada or the United States of a national emergency or war, or other calamity or crisis, in either case, which, in the opinion of any Underwriter, acting reasonably, seriously adversely affects, or involves, or will seriously adversely affect, or involve, the financial markets of the business, operations or affairs of Hydro One; (iii) any inquiry, action, suit, investigation or other proceeding (collectively, a "**Proceeding**"), whether formal or informal, is instituted, announced or threatened (other than Proceedings existing as of the date of the Underwriting Agreement and other Proceedings in connection therewith or related thereto), or any order is made by any federal, provincial, state, municipal or other governmental authority, which, in the opinion of any Underwriter, acting reasonably, operates to prevent or restrict the sale, purchase, distribution or trading of the Debentures or Instalment Receipts; (iv) any order to cease or suspend trading in Hydro One Limited's securities or Instalment Receipts or to prohibit or restrict the distribution of the Debentures, the Common Shares issuable upon conversion of the Debentures or Instalment Receipts is made, or proceedings are announced, commenced or threatened for the making of any such order, by any of the Canadian Securities Regulators or the TSX and has not been rescinded, revoked or withdrawn; (v) there is announced any change or proposed change in law, regulation or policy or the interpretation or administration thereof, if, in the opinion of any Underwriter, acting reasonably, such change, announcement, or proposal materially adversely affects, or may materially adversely affect, the trading of the Debentures, Instalment Receipts, Common Shares issuable upon conversion of the Debentures or the trading of any other securities of Hydro One Limited; or (vi) termination of the Merger Agreement occurs prior to 8:00 a.m. (Toronto time) on the Closing Date.

The Underwriters are obligated to take up and pay for all of the Debentures represented by Instalment Receipts offered hereby (other than the Debentures represented by Instalment Receipts issuable on exercise of the Over-Allotment Option) if any of those Debentures represented by Instalment Receipts are purchased under the Underwriting Agreement. The Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus relating to the Offering.

The Selling Debentureholder has granted to the Underwriters the Over-Allotment Option, which is exercisable in whole or in part at any time prior to the 30th day following the Closing Date and pursuant to which the Underwriters may purchase additional Debentures represented by Instalment Receipts equal to up to 10% of the aggregate principal amount of Debentures represented by Instalment Receipts sold in the Offering on the same terms as set forth above, to cover over-allotments, if any. This Prospectus qualifies the grant of the Over-Allotment Option and the issuance of Debentures represented by Instalment Receipts on the exercise of the Over-Allotment Option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those Debentures represented by Instalment Receipts under this Prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

The Underwriting Agreement provides that the Underwriters will be paid a fee by Hydro One Limited equal to 3.5% of the gross proceeds of the sale of the Debentures ($35.00 per Debenture) in consideration for their services in connection with the Offering. One-half of the fee is payable on the Closing Date and the remaining one-half is payable on the Final Instalment Date. Accordingly, upon payment of the final instalment and assuming the final instalment payment is made for all outstanding Instalment Receipts and that the Over-Allotment Option is not exercised, the total price to the public will be $1,400,000,000, the Underwriters' fee will be $49,000,000 and the net proceeds will be approximately $1,349,500,000, after deducting the expenses of the Offering estimated at $1,500,000. After the Underwriters have made reasonable efforts to sell all the Debentures represented by Instalment Receipts at the Offering Price, the Offering Price may be decreased and may be further changed from time to time to an amount not greater than that set out on the cover page, and the compensation realized by the Underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Debentures represented by Instalment Receipts is less than the gross proceeds paid by the Underwriters to the Selling Debentureholder. The Offering Price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters.

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the Securities in the secondary market, the transparency and availability of trading prices, the liquidity of the Securities and the extent of issuer regulation. The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX. The Corporation has no current intention to list the Debentures for trading on any exchange, as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date.

Once listed, the Instalment Receipts (representing the Debentures) will be quoted and traded on the TSX in the same manner as other debentures listed on the TSX, with all bids and offers for and trades of Instalment Receipts reflecting only the partly paid capital portion of the Debentures and not accrued interest. Accrued interest will be reflected in the settlement amount and in the confirmations generated by the CDS Participant from or through whom the trade was executed. Bid, offer and trading prices for the Instalment Receipts listed on the TSX will be expressed as a percentage of the $1,000 principal amount of a fully paid Debenture (and not as a percentage of the $333 first instalment already paid). In accordance with TSX trading rules, the Instalment Receipts will be quoted based on

$100 principal amounts and all trades in Instalment Receipts will be made in multiples of $1,000. A board lot of Instalment Receipts is represented by one Instalment Receipt, the underlying value of which is $1,000 principal amount of a fully paid Debenture.

Pursuant to rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period ending on the date the selling process for the Debentures represented by Instalment Receipts ends and all stabilization arrangements relating to the Debentures represented by Instalment Receipts are terminated, bid for or purchase Instalment Receipts, Debentures or Common Shares. The foregoing restrictions are subject to certain exceptions including: (i) a bid for or purchase made through the facilities of the TSX, in accordance with the Universal Market Integrity Rules of the Investment Industry Regulatory Organization of Canada; (ii) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (iii) a bid or purchase to cover a short position entered into prior to the commencement of a prescribed restricted period. The Underwriters may engage in market stabilization or market balancing activities on the TSX where the bid for or purchase of the Instalment Receipts, Debentures or Common Shares is for the purpose of maintaining a fair and orderly market in the Instalment Receipts, Debentures or Common Shares, subject to price limitations applicable to such bids or purchases. Such transactions, if commenced, may be discontinued at any time.

The securities offered pursuant to this Prospectus may not be offered or sold in the United States. The Debentures, the Instalment Receipts representing the Debentures, and the Common Shares into which the Debentures may be converted have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "**1933 Act**") or any state securities laws and, may not be offered, or delivered, directly or indirectly, or sold in the United States. The Underwriters have agreed that they will not sell the Debentures represented by Instalment Receipts within the United States. When used in this section, the term "United States" has the meaning ascribed to it in Regulation S under the 1933 Act.

Lock-up Arrangements

Pursuant to the Underwriting Agreement, each of Hydro One Limited and the Selling Debentureholder has agreed that, during the period beginning on the Closing Date and ending on the date that is 90 days following the Closing Date, each of Hydro One Limited and the Selling Debentureholder will not, directly or indirectly, without the prior written consent of RBC Dominion Securities Inc., CIBC World Markets Inc. and BMO Nesbitt Burns Inc., issue, sell, offer, grant any option, warrant or other right to purchase or agree to issue or sell, or otherwise lend, transfer, assign, pledge or dispose of (including without limitation by making any short sale, engaging in any hedging, monetization or derivative transaction or entering into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of Common Shares or other securities of Hydro One Limited or securities convertible into, exchangeable for, or otherwise exercisable into Common Shares or other securities of Hydro One Limited, whether or not cash settled), in a public offering or by way of private placement or otherwise, any equity securities of Hydro One Limited or other securities convertible into, exchangeable for, or otherwise exercisable into Common Shares or other equity securities of Hydro One Limited, or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, other than: (i) the Debentures sold to the Underwriters pursuant to this Prospectus; (ii) Common Shares purchased or delivered under Hydro One Limited's dividend reinvestment plan; or (iii) securities granted, issued or delivered in the ordinary course of business under Hydro One Limited's security-based compensation arrangements, or employee share ownership plans, or pursuant to the conversion, exchange or exercise of any securities so granted, issued or delivered.

RELATIONSHIP BETWEEN HYDRO ONE LIMITED, THE SELLING DEBENTUREHOLDER AND CERTAIN UNDERWRITERS

RBC Dominion Securities Inc., CIBC World Market Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders that have made the Operating Credit Facility available to Hydro One Limited. In addition, RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., Desjardins Securities Inc. and Laurentian Bank Securities Inc. are subsidiaries or affiliates of lenders that have made a $2.3 billion unsecured revolving credit facility available to Hydro One Inc. (the "**Revolving Credit Facility**"). **Consequently, the Corporation and/or the Selling Debentureholder may be considered a "connected issuer" of these Underwriters within the meaning of applicable securities legislation.**

None of these Underwriters will receive any direct benefit from the Offering other than the Underwriters' Fees relating to the Offering. The decision to distribute the Debentures hereunder and the determination of the terms of the Offering were made through negotiation between the Corporation, the Selling Debentureholder and the Underwriters. As of the date of this Prospectus, there was no outstanding indebtedness under the Operating Credit Facility or the Revolving Credit Facility. Neither Hydro One Limited nor Hydro One Inc. is in default of its obligations to the lenders under the Operating Credit Facility or the Revolving Credit Facility, as applicable, and the lenders have not waived any breach of such credit facilities since their execution. Indebtedness under the Operating Credit Facility and the Revolving Credit Facility is unsecured.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to Hydro One Limited and the Selling Debentureholder, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, (collectively, "**Counsel**") the following summary describes the principal Canadian federal income tax considerations generally applicable to a holder who acquires Debentures represented by Instalment Receipts as beneficial owner pursuant to this Offering and who, for the purposes of the application of the Tax Act and at all relevant times: (i) is resident, or is deemed to be resident, in Canada; (ii) holds the Debentures and will hold any Common Shares received on the conversion or maturity of the Debentures (collectively, the "**Securities**") as capital property; (iii) deals at arm's length with Hydro One Limited, the Selling Debentureholder and the Underwriters; and (iv) is not affiliated with Hydro One Limited, the Selling Debentureholder and the Underwriters (a "**Holder**"). Generally, the Securities will be capital property to a Holder provided the Holder does not acquire or hold the Securities in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain holders who might not otherwise be considered to hold their Securities as capital property may, in certain circumstances, be entitled to have the Securities, and all other "Canadian securities" (as defined in the Tax Act) owned by such holders in the taxation year of the election and all subsequent taxation years, deemed to be capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. Holders are advised to consult their personal tax advisors to determine whether such an election is available and desirable in their particular circumstances.

This summary is not applicable to a purchaser: (i) that is a "financial institution", as defined in the Tax Act for the purposes of the mark-to-market rules; (ii) that is a "specified financial institution" as defined in the Tax Act; (iii) an interest which would be a "tax shelter investment" as defined in the Tax Act; (iv) that reports its "Canadian tax results", as defined in the Tax Act, in a currency other than Canadian currency; (v) that enters into a "derivative forward agreement", as defined in the Tax Act, in respect of the Debentures or Common Shares; or (vi) that is a corporation resident in Canada and that is or becomes, or does not deal at arm's length for purposes of the Tax Act with a corporation resident in Canada that is or becomes, as part of a transaction or event or series of transactions or events that includes the acquisition of Securities, controlled by a non-resident corporation for purposes of the foreign affiliate dumping rules in section 212.3 of the Tax Act. Any such purchaser should consult its own tax advisor with respect to an investment in the Securities.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly announced prior to the date hereof (the "**Proposed Amendments**") and Counsel's understanding of the current published administrative practices of the Canada Revenue Agency. This summary assumes that the Proposed Amendments will be enacted in the form proposed; however, no assurance can be given that the Proposed Amendments will be enacted in the form proposed, if at all. This summary does not take into account the discussion paper seeking input on possible approaches to address certain perceived tax advantages of investing passively through a private corporation released, for consultation, by the Minister of Finance (Canada) on July 18, 2017. See, in this regard, "Risk Factors – Risk Factors Relating to the Debentures – Change of Tax Law". This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account any changes in the law, whether by legislative, governmental or judicial action, nor does it take into account any other federal or any provincial, territorial or foreign tax considerations, which may differ from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder, and no representations with respect to the income tax consequences to any Holder are made. Consequently, prospective Holders should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring Securities pursuant to this Offering, having regard to their particular circumstances. This summary does not address any tax considerations applicable to persons other than Holders and such persons should consult their own tax advisors regarding the consequences of acquiring, holding and disposing of Securities under the Tax Act and the laws of any jurisdiction in which they may be subject to tax.

Taxation of Interest on Debentures

A Holder of Debentures represented by Instalment Receipts that is a corporation, partnership, unit trust or any trust of which a corporation or a partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on the Debentures that accrues, or is deemed to accrue, to such Holder to the end of the particular taxation year or that has become receivable by or is received by the Holder before the end of that taxation year, including on a conversion, redemption or repayment at maturity, except to the extent that such interest was included in computing the Holder's income for a preceding taxation year.

Any other Holder, including an individual, will be required to include in computing income for a taxation year all interest on the Debentures that is received or receivable by the Holder in that taxation year (depending upon the method regularly followed by the Holder in computing income), including on a conversion, redemption or repayment at maturity, except to the extent that the interest was included in the Holder's income for a preceding taxation year.

Any Make-Whole Payment will be deemed to be interest received by the Holder at the time of such Make-Whole Payment and will be required to be included in the Holder's income as described above, to the extent that such Make-Whole Payment can reasonably be considered to relate to, and does not exceed the value at the time of such Make-Whole Payment of, the interest that would have been paid or payable on the Debenture for a taxation year ending after the time of such Make-Whole Payment had the Final Instalment Date not occurred on a day that is prior to the first anniversary of the Closing Date.

Exercise of Conversion Privilege

Generally, a Holder who converts a Debenture into Common Shares pursuant to the conversion privilege will be deemed not to have disposed of the Debenture (except for purposes of the deduction for interest included in income but not received as discussed below under "– Disposition of Debentures"). Accordingly, a Holder who converts a Debenture into Common Shares will not be considered to realize a capital gain (or capital loss) on such conversion. Under the current administrative practice of the Canada Revenue Agency, a Holder who, upon conversion of a Debenture, receives cash not in excess of $200 in lieu of a fraction of a Common Share may either treat this amount as proceeds of disposition of a portion of the Debenture, thereby realizing a capital gain (or capital loss), or reduce the adjusted cost base of the Common Shares that the Holder receives on the conversion by the amount of the cash received.

The aggregate cost to a Holder of Common Shares acquired on the conversion of a Debenture will generally be equal to the Holder's adjusted cost base of the Debenture immediately before the conversion, subject to any reduction in respect of cash received in lieu of fractional common shares, as described above. For the purposes of determining the adjusted cost base to a Holder of Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at the time.

Disposition of Debentures

A disposition or deemed disposition of a Debenture by a Holder, including upon redemption or at maturity but not including the conversion of a Debenture into Common Shares pursuant to the Holder's right of conversion as described above, will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (adjusted as described below) are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "– Taxation of Capital Gains and Capital Losses". In this regard, the cost to a Holder of a Debenture represented by an Instalment Receipt will include all amounts paid or payable by the Holder for such Debenture, including the amount of the final instalment, whether paid or unpaid. The proceeds of disposition to a Holder who disposes of a Debenture represented by an Instalment Receipt will include the amount of any unpaid final instalment.

Upon a disposition or deemed disposition, other than upon redemption or at maturity, interest accrued on the Debenture to the date of disposition will be included in computing the Holder's income for the year of disposition, except to the extent that it was included in computing the Holder's income for that or a preceding taxation year, and will be excluded from the Holder's proceeds of disposition of the Debenture. Where a Holder has disposed of a Debenture for consideration equal to its fair market value, the Holder will be entitled to deduct in computing income for the year of disposition any amount that has been included in the Holder's income as interest in respect of such Debenture for that year or any preceding taxation year to the extent such amount exceeds the amount received or receivable by the Holder in respect thereof. A conversion of a Debenture into Common Shares is a disposition for purposes of this rule.

If Hydro One Limited pays the principal amount of the Debentures upon maturity by issuing Common Shares to the Holder, the Holder's proceeds of disposition of the Debenture will be equal to the fair market value, at the time of disposition of the Debenture, of the Common Shares and any other consideration so received. The Holder's aggregate cost of the Common Shares so received will be equal to the fair market value of such Common Shares. For the purposes of determining the adjusted cost base to a Holder of the Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at that time.

Where a Debenture represented by an Instalment Receipt is forfeited to the Selling Debentureholder or is sold by the Custodian as a consequence of the Holder's failure to pay the final instalment, the Holder may be subject to special rules in the Tax Act relating to the seizure by a seller of property previously sold or the settlement or forgiveness of debt. Holders should consult their own tax advisors with respect to these special rules.

Dividends on Common Shares

A Holder will be required to include in computing its income for a taxation year any dividends received (or deemed to be received) on the Common Shares. In the case of a Holder that is an individual (other than certain trusts), such dividends will be subject to the gross-up and dividend tax credit rules applicable to taxable dividends received from "taxable Canadian corporations" (as defined in the Tax Act), including the enhanced gross-up and dividend tax credit applicable to any dividends designated by Hydro One Limited as an "eligible dividend" (as defined in the Tax Act) in accordance with the provisions of the Tax Act.

A dividend received (or deemed to be received) on the Common Shares by a Holder that is a corporation will generally be deductible in computing the corporation's taxable income. In certain circumstances, however, a dividend received (or deemed to be received) by a Holder that is a corporation will be deemed to be a capital gain or proceeds of disposition. Holders that are corporations should consult their own tax advisors having regard to their own circumstances.

A Holder that is a "private corporation", as defined in the Tax Act, or any other corporation controlled, whether because of a beneficial interest in one or more trusts or otherwise, by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), will generally be liable to pay a refundable tax under Part IV of the Tax Act on dividends received (or deemed to be received) on the Common Shares to the extent such dividends are deductible in computing the Holder's taxable income for the taxation year.

Disposition of Common Shares

Generally, on a disposition or deemed disposition of a Common Share, a Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Holder of the Common Share immediately before the disposition or deemed disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "– Taxation of Capital Gains and Capital Losses".

Taxation of Capital Gains and Capital Losses

Generally, a Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "taxable capital gain") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Holder is required to deduct one-half of the amount of any capital loss (an "allowable capital loss") realized in a taxation year from taxable capital gains realized by the Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years. The amount of any capital loss realized by a Holder that is a corporation on the disposition of a Common Share may be reduced by the amount of dividends received or deemed to be received by it on such Common Share to the extent and under the circumstances prescribed by the Tax Act. Similar rules may apply where a Common Share is owned by a partnership or trust of which a corporation, trust or partnership is a member or beneficiary. Such Holders should consult their own tax advisors.

RISK FACTORS

An investment in: (i) the Debentures represented by Instalment Receipts pending payment of the final instalment; (ii) the Debentures following payment of the final instalment; and (iii) the Common Shares issuable upon the conversion of the Debentures, is speculative due to various factors and involves certain risks. A prospective purchaser of Debentures should carefully consider the risk factors and other risks relating to Hydro One's business as described in Hydro One Limited's documents incorporated by reference in this Prospectus, including under:

(i) the heading "Risk Management and Risk Factors" at pages 16 to 23 in the Annual MD&A; and

(ii) the heading "Forward-Looking Statements and Information" at pages 10 to 11 in the Interim MD&A.

In addition, a prospective purchaser of Debentures should carefully consider the risk factors described in this section which relate to the Merger, the Instalment Receipts, the Debentures and the post-Merger business and operations of Hydro One and Avista Corp., as well as the other information contained in this Prospectus (including the documents incorporated herein by reference).

If any of the identified risks were to materialize, it could have a materially adverse effect on the Corporation's future results of operations, business, prospects or financial condition, and could cause actual events to differ materially from those described in forward-looking statements. Additional risks and uncertainties not currently known to the Corporation, or which the Corporation currently deems to be immaterial, may also have an adverse effect on Hydro One and/or its future results of operations, business, prospects or financial condition.

Risk Factors Relating to the Merger

Hydro One Limited may fail to complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated (including with respect to the consideration to be paid in respect of the common stock of Avista Corporation) or at all. The completion of the Merger is subject to receipt of Avista Shareholder Approval and satisfaction of the other Approval Conditions, including certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the HSR Act, clearance of the Merger by CFIUS, the approval by each of IPUC, MPSC, OPUC, RCA, WUTC, FERC and the FCC and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro One Limited will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Corporation could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation the Corporation Termination Fee. See "The Merger Agreement – Termination".

The purchase price could increase

Avista Corporation is a public company and its directors owe fiduciary duties to Avista Corporation shareholders, which may require them to consider competing offers to purchase the common stock of Avista Corporation as alternatives to the Merger. The Merger Agreement preserves the ability of the directors of Avista Corp. to accept an alternative or competing offer in certain circumstances if such offer constitutes a Superior Proposal. If a Superior Proposal to acquire Avista Corporation is made, and if the Superior Proposal results in Avista

Corporation's board of directors making an Adverse Recommendation Change, Avista Corporation is required to negotiate in good faith with Hydro One Limited regarding any revisions to the Merger Agreement, which could result in an increase to the purchase price of the Merger or changes to other terms and conditions of the Merger. See "The Merger Agreement".

Length of time required to complete the Merger is unknown

As described above under "– Hydro One Limited may fail to complete the Merger", the closing of the Merger is subject to the receipt of required Avista Shareholder Approval and certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One Limited provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Merger and on Hydro One's or Avista Corp.'s business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavorable terms and/or conditions on Hydro One Limited or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Corporation could still be required to complete the transaction on the terms set forth in the Merger Agreement. Hydro One Limited intends to complete the Merger as soon as practicable after obtaining the required Avista Shareholder Approval and regulatory approvals and satisfying the other required closing conditions. See "The Merger Agreement – Closing Conditions".

Foreign exchange risk

The cash consideration for the Merger is required to be paid in U.S. dollars, while funds raised in the Offering, which will constitute a significant portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. See "Use of Proceeds". As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One Limited under the Offering, which could cause a failure to realize the anticipated benefits of the Merger.

In addition, the operations of Avista Corp. are conducted in U.S. dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the U.S. dollar relative to the Canadian dollar. In particular, decreases in the value of the U.S. dollar versus the Canadian dollar following the Merger could negatively impact the Corporation's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional demands will be placed on Hydro One as a result of the Merger

As a result of the pursuit and completion of the Merger, additional demands will be placed on the Corporation's managerial, operational and financial personnel and systems. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the Merger. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of funding that would be used to fund the Merger may not be available

Hydro One Limited intends to finance the cash purchase price of the Merger and the Merger-Related Expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Operating Credit Facility; and (iv) existing cash on hand and other sources available to the Corporation.

There is no guarantee that adequate sources of funding will be available to Hydro One Limited or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One Limited being unable to complete the Merger or may negatively impact Hydro One Limited, including its ability to finance the Merger. In addition, any movement in interest rates that could affect the underlying cost of any financing may affect the expected accretion of the Merger.

Hydro One does not currently control Avista Corp.

Although the Merger Agreement contains covenants on the part of Avista Corporation regarding the operation of its business prior to closing the Merger, Hydro One will not control Avista Corp. until completion of the Merger and Avista Corp.'s business and results of operations may be adversely affected by events that are outside of the Corporation's control during the intervening period. Historic and current performance of Avista Corp.'s business and operations may not be indicative of results in future periods. The future performance of Avista Corp. may be influenced by, among other factors, weather, economic conditions, increased environmental or other regulation, turmoil or disruption in financial markets, unfavourable regulatory decisions, rising interest rates, changes or uncertainty in government policy, energy commodity price changes and operational risks, including unplanned outages and other factors beyond the Corporation's control. As a result of any one or more of these factors, among others, the operations and financial performance of Avista Corp. may be negatively affected which may adversely affect the future financial results of Hydro One. See "– Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corp.".

Hydro One Limited expects to incur significant Merger-Related Expenses

Hydro One Limited expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approval. Additional unanticipated costs may be incurred.

Information relating to Avista Corp. in this Prospectus has been obtained from Avista Corporation or its public disclosure record

All information relating to Avista Corporation or its affiliates contained in this Prospectus has been obtained from Avista Corporation or taken from Avista Corporation's public disclosure record. Although the Corporation has conducted what it believes to be a prudent and thorough level of investigation in connection with the Merger and the disclosure relating to Avista Corp. contained in this Prospectus, an unavoidable level of risk remains regarding the accuracy and completeness of such information. While Hydro One has no reason to believe the information obtained from Avista Corporation or taken from the public disclosure record is misleading, untrue or incomplete, Hydro One cannot assure the accuracy or completeness of such information nor can Hydro One compel Avista Corporation to disclose events which may have occurred or may affect the completeness or accuracy of such information but which are unknown to Hydro One.

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corp.

Hydro One will substantially increase its amount of indebtedness following the Merger

After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US$1.9 billion of debt of Avista Corp. assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a *pro forma* basis after giving effect to the Merger, but assuming conversion of all Debentures to Common Shares (assuming no exercise of the Over-Allotment Option), details of which are included in the capitalization table provided herein, Hydro One would have had approximately $17.098 billion of total indebtedness outstanding. See "Capitalization". Hydro One will substantially increase its amount of indebtedness following the Merger and such increased indebtedness may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering could result in a downgrade of Hydro One's credit ratings

The change in the capital structure of Hydro One Limited as a result of the Merger and the Offering could cause credit rating agencies which rate the outstanding debt obligations of Hydro One Limited and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Corporation's borrowing costs.

Hydro One Limited's historical and pro forma combined financial information may not be representative of the results of the Corporation following the Merger

The *pro forma* combined financial information included in this Prospectus has been prepared using the consolidated historical financial statements of Hydro One Limited and the consolidated historical financial statements of Avista Corporation and does not purport to be indicative of the financial information that will result from the operations of Hydro One Limited on a consolidated basis following the Merger. In addition, the *pro forma* financial information included in this Prospectus is based in part on certain assumptions regarding the Merger that Hydro One currently believes are reasonable. Hydro One makes no assurances that its current assumptions will prove to be accurate over time. Accordingly, the historical and *pro forma* financial information included in this Prospectus does not necessarily represent the Corporation's results of operations and financial condition had Hydro One and Avista Corp. operated as a combined entity during the periods presented, or of the Corporation's consolidated results of operations and financial condition in the future. Additionally, the actual amount assigned to the fair values of the identifiable assets and liabilities acquired will result in changes to earnings in periods subsequent to the Merger, and those changes could be material.

In preparing the *pro forma* financial information contained in this Prospectus, Hydro One Limited has given effect to, among other items, the Offering, the completion of the Merger and the assumption of Avista Corp.'s outstanding indebtedness. Hydro One Limited has also assumed that the Debentures will be converted into Common Shares on or immediately following the Final Instalment Date. While management believes that the estimates and assumptions underlying the *pro forma* financial information are reasonable, such assumptions and estimates may be materially different than the Corporation's actual experience following completion of the Merger. See also "– Risk Factors Relating to the Merger" and "Presentation of Financial Information". See the notes to the *pro forma* financial statements of Hydro One Limited in this Prospectus.

Potential undisclosed liabilities associated with the Merger

In connection with the Merger, there may be liabilities of Avista Corp. that the Corporation failed to discover or was unable to quantify in the due diligence which it conducted prior to the execution of the Merger Agreement. The discovery or quantification of any material liabilities of Avista Corp. could have a material adverse effect on Hydro One's business, financial condition, results of operations or future prospects.

The Corporation will not be obligated to close the Merger if (i) there are inaccuracies in the representations and warranties made by Avista Corporation in the Merger Agreement as to its liabilities which would reasonably be expected to have an Avista Material Adverse Effect, (ii) if any Final Orders impose or require any obligations that would, individually or in the aggregate, constitute a Burdensome Condition or (iii) if any Avista Material Adverse Effect has occurred, subject to certain prescribed exceptions, as described in further detail under "The Merger Agreement – Closing Conditions".

Following the closing of the Merger, Avista Corporation will have become an indirect wholly-owned subsidiary of the Corporation and the full merger consideration under the Merger Agreement will have been paid, and the Corporation will have no further recourse (against Avista Corporation, its shareholders or any other persons) and will fully bear the risk for any inaccuracies in the information, representations or warranties provided by Avista Corporation in the Merger Agreement and any material liabilities of Avista Corp.

Hydro One may be unable to successfully realize the anticipated benefits of the Merger

Hydro One believes that the Merger will provide benefits to the Corporation. See "The Merger – Merger Highlights". However, there is a risk that some or all of the expected benefits of the Merger may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. The past financial performance of the Corporation or Avista Corporation may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the Merger may include terms which could have an adverse effect on the Corporation's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure. Failure to realize the anticipated benefits of the Merger may impact the financial performance of the Corporation and the price of its Common Shares.

Reputational and Public Opinion Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Corporation's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Hydro One may not be successful in retaining the services of key personnel of Avista Corp. following the Merger

Hydro One currently intends to retain key personnel of Avista Corp. following the completion of the Merger to continue to manage and operate Avista Corp. as a separate operating company. Hydro One will compete with other potential employers for employees, and it may not be successful in keeping the services of the executives and other employees of Avista Corp. that it needs to realize the anticipated benefits of the Merger. Hydro One's failure to retain key personnel to remain as part of the management team of Avista Corp. in the period following the Merger could have a material adverse effect on the business and operations of Avista Corp. and Hydro One on a consolidated basis.

Hydro One is subject to risks associated with its results of operations and financing risks

Management of Hydro One believes, based on its current expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Merger), that the cash flow from its operations and funds available to it under the Operating Credit Facility and the revolving credit facilities of the subsidiaries of Hydro One Limited and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about Avista Corp. and its operations and there can be no assurance that such information is correct and complete in all material respects.

Hydro One's degree of leverage could have adverse consequences for Hydro One, particularly if a significant portion of the Debentures are not converted into Common Shares by the holders thereof. The significant increase in the degree of Hydro One's leverage in connection with the Merger could, among other things, limit Hydro One's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict Hydro One's flexibility and discretion to operate its business; limit Hydro One Limited's ability to declare dividends on its Common Shares; require Hydro One to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade Hydro One's existing credit ratings; expose Hydro One to increased interest expense on borrowings at variable rates; limit Hydro One's ability to adjust to changing market conditions; place Hydro One at a competitive disadvantage compared to its competitors that have less debt; make Hydro One vulnerable to any downturn in general economic conditions; and render Hydro One unable to make expenditures that are important to its future growth strategies.

Hydro One will need to refinance or reimburse amounts outstanding under Hydro One's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of Hydro One will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the ability of Hydro One Limited to declare dividends may be adversely affected.

The ability of Hydro One to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of Hydro One, debt service obligations, the realization of the anticipated benefits of the Merger and working capital and future capital expenditure requirements. In addition, the ability of Hydro One to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under Hydro One's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends and distributions by Hydro One and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of Hydro One would be sufficient to repay such indebtedness in full. There can also be no assurance that Hydro One will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at Avista Corp.

The business of Avista Corp. is concentrated in the State of Washington with business also conducted in Idaho, Oregon Montana and Alaska. Economic conditions in these states and in Avista Corp.'s service territories could change and if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline, adversely affecting Avista Corp.'s results of operations, net income and cash flows and those of the Corporation following the Merger.

Developments in technology could reduce demand for electricity and gas

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity, transporting gas or make the existing generating facilities of Avista Corp. uneconomic. In addition, advances in such technologies could reduce electrical or natural gas demand, which could negatively impact the results of operations, net income and cash flows of Avista Corp. and those of the Corporation following the Merger.

Weather (temperatures, precipitation levels, wind patterns and storms) has a significant effect on Avista Corp.'s results of operations, financial condition and cash flows

Weather impacts are described in the following subtopics:

- certain retail electricity and natural gas sales,
- the cost of natural gas supply, and
- the cost of power supply.

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures

Avista Corp. normally has its highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. Avista Corp. also has high electricity demand for air conditioning during the summer (third quarter) in the Pacific Northwest. In general, warmer weather in the heating season and cooler weather in the cooling season will reduce its customers' energy demand and retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by Avista Corp.'s decoupling mechanisms; however, Avista Corp. could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates.

The cost of natural gas supply tends to increase with higher demand during periods of cold weather

Increased costs adversely affect cash flows when Avista Corp. purchases natural gas for retail supply at prices above the amount then allowed for recovery in retail rates. Avista Corp. defers differences between actual natural gas supply costs and the amount currently recovered in retail rates and Avista Corp. is generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in Avista Corp.'s region, even though there may be less extreme weather conditions in Avista Corp.'s area.

The cost of power supply can be significantly affected by weather

Precipitation (consisting of snowpack, its water content and melting pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect Avista Corp.'s reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, significantly more costly power supply resources must be acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary based on wind patterns as wind generation capacity is material in Avista Corp.'s region but its contribution to supply is inconsistent.

The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. Avista Corp. may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation also tends to increase during periods of high demand which are often related to temperature extremes. Avista Corp. may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by Avista Corp.'s regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by Avista Corp. in current expense and it is partially deferred or shared with customers through regulatory mechanisms.

The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation are producing output that may be supported by price subsidies. In extreme situations, Avista Corp. may be required to sell excess energy at negative prices.

As a result of these combined factors, Avista Corp.'s net cost of power supply – the difference between its costs of generation and market purchases, reduced by its revenue from wholesale sales – varies significantly because of weather.

Avista Corp. relies on regular access to financial markets but cannot assure favourable or reasonable financing terms will be available when Avista Corp. needs them

Access to capital markets is critical to Avista Corp.'s operations and its capital structure

Avista Corp. has significant capital requirements that it expects to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies impacts Avista Corp.'s financial condition. Avista Corp. could experience increased borrowing costs or limited access to capital on reasonable terms.

Avista Corp. accesses long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time-to-time. Avista Corp.'s ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond its control. If Avista Corp. is unable to obtain capital on reasonable terms, it may limit or prohibit its ability to finance capital expenditures and repay maturing long-term debt. Avista Corp.'s liquidity needs could exceed its short-term credit availability and lead to defaults on various financing arrangements.

Performance of the financial markets could also result in significant declines in the market values of assets held by its pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense.

Avista Corp. relies on credit from financial institutions for short-term borrowings

Avista Corp. needs adequate levels of credit with financial institutions for short-term liquidity. Avista Corporation has a US$400.0 million committed line of credit that expires in April 2021. Avista Corporation's subsidiary AEL&P has a US$25.0 million committed line of credit that expires in November 2019. There is no assurance that Avista Corp. will have access to credit beyond these expiration dates. The committed line of credit agreements contain customary covenants and default provisions.

Any default on the lines of credit or other financing arrangements of Avista Corporation or any of its "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for Avista Corp. to obtain financing on reasonable terms to pay creditors or fund operations.

Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements

If market interest rates decrease below the interest rates Avista Corp. has locked in, this will result in a liability related to its interest rate swap derivatives, which can be significant. As of March 31, 2017, Avista Corp. had a net interest rate swap derivative liability of US$53.9 million, reflecting a decline in interest rates since the time Avista Corp. entered into the agreements. Avista Corp. does not have any U.S. Treasury lock agreements outstanding as of March 31, 2017. Avista Corp. may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact Avista Corp's liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

Downgrades in Avista Corporation's credit ratings could impede its ability to obtain financing, adversely affect the terms of financing and impact its ability to transact for or hedge energy resources

If Avista Corporation does not maintain its investment grade credit rating with the major credit rating agencies, it could expect increased debt service costs, limitations on its ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with Avista Corp. or result in the termination of outstanding regulatory authorizations for certain financing activities.

Credit risk may be affected by industry concentration and geographic concentration

Avista Corp. has concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- oil and natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

Avista Corp. has concentrations of credit risk related to its geographic location in the western United States and western Canada energy markets. These concentrations of counterparties and concentrations of geographic location may affect Avista Corp.'s overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

Regulators may not grant rates that provide timely or sufficient recovery of Avista Corp.'s costs or allow a reasonable rate of return

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue growth. Avista Corp.'s ability to recover these expenses and capital costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. Avista Corp. expects to periodically file for rate increases with regulatory agencies to recover its expenses and capital costs and provide an opportunity to earn a reasonable rate of return. If regulators do not grant rate increases or grant substantially lower rate increases than Avista Corp. requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on Avista Corp.'s operating revenues, net income and cash flows. During December 2016, the WUTC denied Avista Corp.'s 2016 electric and natural gas general rate requests and granted zero rate relief. Avista Corp. filed a petition for reconsideration and alternately for rehearing of its 2016 general rate cases, which was denied by the WUTC in February 2017. Avista Corp. has determined it will not appeal the WUTC's decision to the courts and as a result, Avista Corp. expects its 2017 annual earnings to decrease by US$0.20 to US$0.30 per diluted share as compared to 2016 actual results (without consideration to its 2017 Washington general rate cases that were filed in May 2017). This equates to an expected reduction of Avista Corp.'s 2017 utility return on equity of 100 to 120 basis points.

In the future, Avista Corp. and/or Hydro One may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations

If Avista Corp. and/or Hydro One could no longer apply regulatory accounting, it could be:

- required to write off its regulatory assets, and
- be precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if Avista Corp. and/or Hydro One is expected to recover these amounts from customers in the future.

Energy commodity price changes affect Avista Corp.'s cash flows and results of operations

Energy commodity prices can be volatile

Avista Corp. relies on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. A combination of factors exposes its operations to commodity price risks, including:

- Avista Corp.'s obligation to serve its retail customers at rates set through the regulatory process - Avista Corp. cannot change retail rates to reflect current energy prices unless and until it receives regulatory approval,
- customer demand, which is beyond Avista Corp.'s control because of weather, customer choices, prevailing economic conditions and other factors,
- some of Avista Corp.'s energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of its energy resource costs are not fixed), and
- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

Because Avista Corp. must supply the amount of energy demanded by its customers and it must sell it at fixed rates and only a portion of its energy supply costs are fixed, Avista Corp. is subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities.

When Avista Corp. enters into fixed price energy commodity transactions for future delivery, Avista Corp. is subject to credit terms that may require it to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on Avista Corp.'s cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Cash flow deferrals related to energy commodities can be significant

Avista Corp. is permitted to collect from customers only amounts approved by regulatory commissions. However, Avista Corp.'s costs to provide energy service can be much higher or lower than the amounts currently billed to customers. Avista Corp. is permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect Avista Corp.'s results of operations.

Even if Avista Corp.'s regulators ultimately allow Avista Corp. to recover deferred power and natural gas costs, Avista Corp.'s operating cash flows can be negatively affected until these costs are recovered from customers.

Fluctuating energy commodity prices and volumes in relation to Avista Corp.'s energy risk management process can cause volatility in its cash flows and results of operations

Avista Corp. engages in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. Avista Corp. routinely enters into contracts to hedge a portion of its purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. Avista Corp. uses physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. Avista Corp. does not attempt to fully hedge its energy resource assets or its forecasted net positions for various time horizons. To the extent Avista Corp. has positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on Avista Corp.'s operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows.

The hedges Avista Corp. enters into are reviewed for prudence by Avista Corp.'s various regulators and any deferred costs (including those as a result of Avista Corp.'s hedging transactions) are subject to review for prudence and potential disallowance by regulators.

Generation plants may become obsolete

Avista Corp. relies on a variety of generation and energy commodity market sources to fulfill its obligation to serve customers and meet the demands of its counterparty agreements. There is the potential that some of Avista Corp.'s generation sources, such as coal, may become obsolete. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life.

Avista Corp. is subject to various operational and event risks

Avista Corp.'s operations are subject to operational and event risks that include:

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, which can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies, support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,
- fuel cost and availability, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining its generation, transmission and distribution systems,
- damage or injuries to third parties caused by its generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations, and
- terrorist attacks or other malicious acts that may disrupt or cause damage to Avista Corp.'s utility assets or the vendors it utilizes.

Disasters may affect the general economy, financial and capital markets, specific industries, or Avista Corp.'s ability to conduct business. As protection against operational and event risks, Avista Corp. maintains business continuity and disaster recovery plans, maintains insurance coverage against some, but not all, potential losses and seeks to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect against liability, extra expenses and operating disruptions from all of the operational and event risks described above. In addition, Avista Corp. is subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations to it.

Damage to facilities may be caused by severe weather, such as snow, ice, wind storms or avalanches. The cost to implement rapid or any repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather.

Adverse impacts may occur at Avista Corp.'s Alaska operations that could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to the lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel)

AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham hydroelectric project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Any issues that negatively affect AEL&P's ability to generate or transmit power or any decrease in the demand for the power generated by AEL&P could negatively affect Avista Corp's results of operations, financial condition and cash flows.

There have been numerous changes in legislation, related administrative rulemakings, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect Avista Corp.'s operational and financial performance

Avista Corp. expects to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. Avista Corp. is also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC perform periodic audits of Avista Corp. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties of up to US$1 million per day per violation.

Future legislation or administrative rules could have a material adverse effect on Avista Corp.'s operations, results of operations, financial condition and cash flows.

Actions or limitations to address concerns over the long-term global and Avista Corp.'s utilities' service area climate changes may affect Avista Corp's operations and financial performance

Legislative, regulatory and advocacy efforts at the state, national and international levels concerning climate change and other environmental issues could have significant impacts on Avista Corp.'s operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including that resulting from the use of natural gas by Avista Corp. customers. Such proposals, if adopted, could restrict the operation and raise the costs of Avista Corp.'s power generation resources as well as the distribution of natural gas to its customers.

Avista Corp. expects continuing activity in the future and will evaluate the extent to which potential changes to environmental laws and regulations may:

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of Avista Corp.'s existing generating plants,
- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from Avista Corp.'s generating plants,
- restrict the types of generating plants that can be built or contracted with,
- require construction of specific types of generation plants at higher cost, and
- increase the cost of distributing natural gas to customers.

Avista Corp. has contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters

In the normal course of Avista Corp.'s business, it has matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. Although Avista Corp. believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows, it is possible that a significant change could occur in Avista Corp's estimates of the probability or amount of a liability being incurred. Moreover, Avista Corp. cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by Avista Corp. may be recoverable through the ratemaking process. Avista Corp. is subject to environmental regulation by federal, state and local authorities related to its past, present and future operations.

Cyber-attacks, terrorism or other malicious acts could disrupt Avista Corp.'s businesses and have a negative impact on its results of operations and cash flows

In the course of Avista Corp.'s operations, it relies on interconnected technology systems for operation of its generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, Avista Corp. collects and retains sensitive information including personal information about its customers and employees.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors. In particular, cyber-attacks, terrorism or other malicious acts could damage, destroy or disrupt these systems. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to these same risks and, to the extent of interconnection to Avista Corp.'s technology, may impact Avista Corp. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect Avista Corp.'s reputation and competitiveness, could result in costly litigation and negatively impact Avista Corp.'s results of operations. As these potential cyber-attacks become more common and sophisticated, Avista Corp. could be required to incur costs to strengthen its systems and respond to emerging concerns.

Terrorist attacks could also be directed at physical electric and natural gas facilities, as well as technology systems.

Avista Corp. may be adversely affected by its inability to successfully implement certain technology projects

Avista Corp. is currently planning to replace all of its electric meter infrastructure in the State of Washington with two-way communication advanced metering infrastructure ("**AMI**"). There is the risk that regulators will not allow the full recovery of new AMI. In addition, there are inherent risks associated with replacing and changing these types of systems, such as incorrect or non-functioning metering and/or delayed or inaccurate customer bills or unplanned outages, which could have a material adverse effect on Avista Corp.'s results of operations, financial condition and cash flows. Finally, there is the risk that Avista Corp. does not ultimately complete the project and will incur contract cancellation or other costs, which could be significant.

Avista Corp.'s strategic business plans, which may be affected by any or all of the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and the extent of its business development efforts where potential future business is uncertain

Avista Corp.'s strategic business plans could be affected by its result in any of the following:

- disruptive innovations in the marketplace may outpace Avista Corp.'s ability to compete or manage its risk,
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities,
- market or other conditions may adversely affect Avista Corp.'s operations or require changes to its business strategy, which could result in a non-cash goodwill impairment charge that would reduce assets and reduce Avista Corp.'s net income, and
- potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode customer and community satisfaction with Avista Corp.

Risk Factors Relating to the Instalment Receipts

The balance of the Instalment Receipt purchase price remains outstanding and the failure of a holder of Instalment Receipts to pay the balance of the purchase price on or before the Final Instalment Date will have adverse consequences for the holder

Each Instalment Receipt purchased in the Offering represents an obligation of the holder of such security to pay $667 per $1,000 principal amount of Debentures on or before the Final Instalment Date. If the final instalment of the purchase price is not paid when due, the Defaulting Holder will no longer be able to pay the final instalment without the consent of the Selling Debentureholder. In addition, the Defaulting Holder will no longer be able to exercise the rights described under "Details of the Offering – Instalment Receipts – Rights and Privileges" and will cease to be entitled to any repayment of principal in respect of the Debenture represented by such Instalment Receipt. In addition, if the holder of an Instalment Receipt does not pay the final instalment when due, the Debentures evidenced by such Instalment Receipt may, at the Selling Debentureholder's option, upon compliance with applicable law and the terms of the Instalment Receipt Agreement, be forfeited to the Selling Debentureholder in full satisfaction of the Defaulting Holder's obligations or such Debentures may be sold and the Defaulting Holder will remain liable for any deficiency in the proceeds of such sale. The Selling Debentureholder will have the right to and may commence legal action against Defaulting Holders who do not pay the final instalment on or before the Final Instalment Date. The commencement of any such litigation by the Selling Debentureholder may negatively affect the Corporation and the Selling Debentureholder, and could have an adverse effect on the price of the Debentures and the Common Shares.

There is currently no market through which the Instalment Receipts may be sold

There is currently no market through which the Instalment Receipts may be sold and purchasers of Debentures may not be able to resell Instalment Receipts. There can be no assurance that an active trading market will develop for the Instalment Receipts after the Offering or, if developed, that such a market will be sustained. This may affect the pricing of the Instalment Receipts in the secondary market, the transparency and availability of trading prices, the liquidity of Instalment Receipts, and the extent of issuer regulation. If an active market for the Instalment Receipts fails to develop or be sustained, the prices at which the Instalment Receipts trade may be adversely affected. Whether or not the Instalment Receipts will trade at lower prices depends on many factors, including liquidity of the Instalment Receipts, prevailing interest rates and the market for similar securities, the market price of debt securities with maturities comparable to the Debentures, the market price of the Common Shares, general economic conditions and Hydro One's financial condition, historic financial performance and future prospects.

The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX and there is no assurance that the TSX will approve such listing application. The Corporation has no current intention to list the Debentures for trading on the TSX or any other exchange as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date.

Fluctuations in trading price

An Instalment Receipt entitles the holder to unencumbered ownership of a Debenture upon payment of the final instalment on or before the Final Instalment Date. Interest rate movements will cause the value of debt instruments with a maturity comparable to the Debentures to fluctuate, and this will be reflected in the market price of the Instalment Receipts. The price volatility of the Instalment Receipts will be greater than the price volatility of debt instruments of a maturity comparable to the Debentures. This is due to the fact that the payment for the Instalment Receipts represents only 33.3% of the total principal amount payable for the underlying Debenture.

Further, the market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Instalment Receipts to sell the Instalment Receipts at an advantageous price, particularly if the market price for Common Shares falls below the Conversion Price of Debentures represented by Instalment Receipts. In addition, it may result in greater volatility in the market price of the Instalment Receipts than would be expected for other debt securities or for non-convertible or non-exchangeable securities. Market price fluctuations in the Common Shares may be due to, among other things, the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Merger, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Hydro One, along with a variety of additional factors. These broad market fluctuations may adversely affect the prices of the Instalment Receipts and the Common Shares.

Rights of holders of Instalment Receipts may change

Purchasers of Debentures will, prior to payment of the final instalment, be holders of Instalment Receipts and will be bound by the terms and conditions of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that, pending payment of the final instalment, legal title to the Debentures offered hereby will be held by the Custodian on behalf of the Selling Debentureholder pursuant to the pledge to secure the payment of the final instalment. The terms and conditions of the Instalment Receipt Agreement may be amended in certain circumstances, including with the approval of holders of Instalment Receipts representing two-thirds of the principal amount of the Debentures represented thereby. The description of the Instalment Receipt Agreement contained in this Prospectus is qualified in its entirety by the provisions of such agreement, which should be reviewed by holders of Instalment Receipts. The Instalment Receipt Agreement will be filed by Hydro One Limited on SEDAR on or about the Closing Date.

The Right to receive unencumbered Debentures may terminate

The Corporation has the obligation to redeem the Debentures at a price equal to their principal amount plus accrued and unpaid interest (without any Make-Whole Payment) following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Merger Agreement in accordance with its terms; and (iii) May 1, 2019 if the Final Instalment Notice has not been given on or before April 30, 2019. See "Details of the Offering – Debentures – Redemption". Accordingly, it is possible that Instalment Receipts will be outstanding for a very limited period of time. Upon such redemption, a holder will no longer be entitled to pay the final instalment or to receive any unencumbered Debentures and will only be entitled to receive a net payment equal to the redemption price less the amount of the final instalment otherwise payable by such holder to the Selling Debentureholder plus accrued and unpaid interest thereon. Until the Approval Conditions are satisfied and the Debentures are delivered to holders of Instalment Receipts pursuant to the Instalment Receipt Agreement, such holders have the rights described under "Details of the Offering – Instalment Receipts".

While the right of holders of Instalment Receipts to receive unencumbered Debentures may terminate as a result of a redemption by the Corporation of the Debentures as described herein, the Merger could potentially still be completed by the Corporation. If the Merger is completed following the redemption of the Debentures, holders of Instalment Receipts will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Merger.

Merger may be completed on other terms

Both before and after payment of the final instalment, the Corporation may, in its sole discretion, amend the Merger Agreement and consummate the Merger on terms that may be substantially different from those contemplated in this Prospectus. Any such change will not affect the obligation of the holder of an Instalment Receipt to pay the final instalment on or before the Final Instalment Date. See "The Merger Agreement" and "– Risk Factors Relating to the Merger – Hydro One Limited may fail to complete the Merger".

Risk Factors Relating to the Debentures

There is currently no market through which the Debentures may be sold

There is currently no market through which the Debentures may be sold and purchasers of Debentures may not be able to resell Debentures purchased under this Prospectus. The Corporation has not applied to list the Debentures for trading on the TSX, but has received conditional approval to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Accordingly, an investor who does not exercise the conversion privilege in respect of fully paid Debentures will be holding what Hydro One Limited expects will be highly illiquid securities. There can be no assurance that an active trading market will develop for the Debentures after payment of the final instalment or, if developed, that such a market will be sustained. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of Debentures, and the extent of issuer regulation. If an active market for the Debentures fails to develop or be sustained, the prices at which the Debentures trade may be adversely affected. Whether or not the Debentures will trade at lower prices depends on many factors, including, among others, liquidity of the Debentures, prevailing interest rates and the market for similar securities, the market price of the Common Shares, general economic conditions and the Corporation's financial condition, historic financial performance and future prospects.

Fluctuations in trading price

After the Final Instalment Date, Debentures will stop accruing interest. Accordingly, their value will be a function of the value of the underlying Common Shares into which the Debenture is convertible. The market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Debentures to sell the Debentures at an advantageous price. In addition, it may result in greater volatility in the market price of the Debentures than would be expected for other debt securities or non-convertible securities.

Market price fluctuations in the Common Shares may be due to the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Merger, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Hydro One, along with a variety of additional factors.

Existing and prior ranking of indebtedness

On the Closing Date, the Corporation expects to have consolidated indebtedness of approximately $12.740 billion (including the Debentures, excluding the Over-Allotment Option). After giving effect to the Merger, assuming receipt of the aggregate total amount of the final instalment for each of the Debentures (excluding those issuable upon exercise of the Over-Allotment Option), conversion of all Debentures into Common Shares and the assumption of Avista Corp.'s outstanding indebtedness, management estimates that the consolidated indebtedness of the Corporation will be approximately $17.098 billion (calculated as of March 31, 2017). See "Financing of the Merger" and "Capitalization".

The Debentures will be subordinate to all Senior Indebtedness of the Corporation. See "Details of the Offering – Debentures – Subordination". Therefore, in the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the Corporation, the assets of the Corporation would be made available to satisfy its obligations with respect to the Debentures only after it has paid all of its secured creditors and all holders of Senior Indebtedness. Accordingly, all or a substantial portion of the Corporation's assets could be unavailable to satisfy the claims of holders of the Debentures. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding. See "– Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corp.".

The Debentures will be effectively subordinated to the debt and other liabilities of Hydro One Limited's subsidiaries and to any future secured debt of Hydro One Limited

Hydro One Limited's subsidiaries will not guarantee or otherwise be responsible for the payment of principal or interest or other payments required to be made by Hydro One Limited on the Debentures. Accordingly, the Debentures will be effectively subordinated to all existing and future liabilities (including trade payables and debt) of Hydro One Limited's subsidiaries. In the event of an insolvency, bankruptcy, liquidation, reorganization or similar proceeding in respect of any of Hydro One Limited's subsidiaries, holders of the Debentures will have no right to proceed against the assets of such subsidiaries. Creditors of such subsidiaries would generally be entitled to payment in full from such assets before any assets are made available for distribution to Hydro One Limited to pay its debts and other obligations. The Debentures will also be effectively subordinated in right of payment to any future secured debt of Hydro One Limited, to the extent of the value of the assets securing such debt.

Absence of covenant protection

The Indenture does not restrict the Corporation or any of its subsidiaries from incurring additional indebtedness for borrowed money or otherwise from mortgaging, pledging or charging their properties to secure any indebtedness or other financing. The Indenture does not contain any provisions specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving the Corporation or any of its subsidiaries.

The rights of holders of Debentures may change

Holders of Debentures will be bound by the terms and conditions of the Indenture. The terms and conditions of the Indenture may be amended in certain circumstances, including with the approval of two-thirds of holders of outstanding Debentures. The description of the Indenture contained in this Prospectus is qualified in its entirety by the provisions of the Indenture, which should be reviewed by holders of Instalment Receipts and Debentures. The Indenture will be filed by Hydro One Limited on SEDAR on or about the Closing Date.

Redemption prior to maturity may prevent holders from exercising their conversion privilege

The Debentures may be redeemed, at the option of the Corporation and without the consent of holders of Debentures, subject to certain conditions, after the Final Instalment Date and prior to the Maturity Date at a redemption price equal to the principal amount thereof, plus any unpaid interest which accrued prior to the Final Instalment Date, as described under "Details of the Offering – Debentures – Redemption".

The right of holders of Debentures to receive Common Shares will terminate as a result of a redemption by the Corporation of the Debentures as described herein. If a holder of Debentures has its Debentures redeemed by the Corporation following completion of the Merger, but prior to conversion by the holder of such Debentures into Common Shares, such holder will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Merger. In addition, the redemption price of the Debentures may be worth less than the consideration obtained on a conversion of those Debentures by the holder thereof.

Conversion of Debentures following satisfaction of the Approval Conditions can be negatively affected by the market price of the Common Shares

Subject to satisfaction of the Approval Conditions and payment of the final instalment by the holder of an Instalment Receipt on or prior to the Final Instalment Date, such holder may convert its Debentures after the Final Instalment Date but prior to the earlier of the date of redemption or the Maturity Date. The Conversion Price will be \$21.40 per Common Share, being a conversion rate of 46.7290 Common Shares per \$1,000 principal amount of Debentures, subject to adjustment in certain circumstances. See "Details of the Offering – Debentures – Conversion Right". If the market price of the Common Shares is less than the Conversion Price, the trading price of the Debentures will be negatively impacted. If the market price of the Common Shares is less than the Conversion Price on the date of conversion by a holder, such holder will receive fewer Common Shares on conversion of its Debentures than they would be able to purchase with funds equal to the principal amount of its Debentures.

Issuance of common shares upon conversion of the Debentures may be restricted if such issuance would violate the Electricity Act, 1998 (Ontario)

Voting securities of Hydro One Limited, which include the Common Shares, are subject to share ownership restrictions under the *Electricity Act, 1998* (Ontario). The share ownership restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds voting securities of Hydro One Limited solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, may beneficially own or exercise control or direction over more than 10% of any class or series of voting securities of Hydro One Limited. The articles of Hydro One Limited provide for comprehensive enforcement mechanisms that are applicable in the event of a contravention of the share ownership requirements. **A potential purchaser of Debentures represented by Instalment Receipts should not subscribe for a number of such Debentures in this Offering that would, upon conversion of such Debentures into Common Shares, cause such purchaser to violate this prohibition.** Under the Indenture, the Corporation has reserved the right to not issue Common Shares to a holder upon conversion of the Debentures in the event the Corporation reasonably determines that issuing such Common Shares to such holder would result in such holder breaching the share ownership restrictions under the *Electricity Act, 1998* (Ontario) or be prohibited by the Corporation's articles.

Interest on Debentures will cease to be payable prior to the Maturity Date

After giving the Final Instalment Notice, Hydro One Limited has the right, but not the obligation, to redeem any outstanding and unconverted Debentures at any time on or after the Final Instalment Date and prior to the Maturity Date, but may choose not to redeem such Debentures. Any unconverted Debentures outstanding on or after the day following the Final Instalment Date will cease to accrue interest. A holder who has not exercised its conversion privilege by such date will be holding a convertible debt security which no longer earns interest.

The likelihood that holders of the Debentures will receive payments owing to them under the terms of the Debentures will depend on the financial health of the Corporation and its creditworthiness

Although Hydro One Limited currently has an investment grade credit rating, there is no assurance the Corporation will have sufficient capital to repay the Debentures in cash on redemption or at the Maturity Date or that it will be able to raise sufficient capital on acceptable terms by the applicable redemption date or the Maturity Date to repay the outstanding Debentures. While Hydro One Limited covenants to maintain readily available capacity under its revolving credit facilities (on a consolidated basis), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and on the closing of the Over-Allotment Option, if applicable), in the event of a mandatory redemption, there can be no certainty that the revolving credit facilities (on a consolidated basis), or such cash on hand, will continue to be available at the time of redemption, such that Hydro One Limited may not have sufficient funds to repay the Debentures. The risk of default in any payment obligation by Hydro One Limited may increase to the extent that there is a significant decline in the price of the Common Shares.

Debentures are unsecured obligations

The Debentures are unsecured obligations of the Corporation and are not secured by any of its assets or assets of any current or future subsidiaries of the Corporation.

Prevailing yields on similar securities

The prevailing yield on debt securities with comparable maturities will affect the market value of the Debentures. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing yields for similar securities rise, and will increase as prevailing yields for similar securities decline. The market value of the Debentures may also decline after the Debentures cease to accrue interest depending on the value of the underlying Common Shares.

Dilutive effects on shareholders

The issuance of Common Shares on conversion of the Debentures may have a dilutive effect on shareholders of Common Shares of Hydro One Limited and an adverse impact on the price of the Common Shares, which may also adversely impact the price of the Debentures. Potential future offerings by Hydro One Limited of Common Shares or securities convertible into or exchangeable for Common Shares would dilute purchasers acquiring securities under this Prospectus.

Investment eligibility is not guaranteed

The Corporation will endeavour to ensure that the Debentures represented by Instalment Receipts and the Common Shares continue to be qualified investments for Exempt Plans under the Tax Act, although there is no assurance that the conditions prescribed for such qualified investments will be adhered to at any particular time. The Tax Act imposes taxes in respect of the acquisition or holding of non-qualified or prohibited investments by Exempt Plans.

Income tax consequences

The income of the Corporation and its subsidiaries must be computed and is taxed in accordance with Canadian and other applicable tax laws, all of which may be changed in a manner that could adversely affect the holders of Debentures or Common Shares or the Corporation, including the latter's ability to service the Debentures or pay dividends on the Common Shares. There can be no assurance that taxation authorities will accept the tax positions adopted by the Corporation or its subsidiaries, including their determinations of the amounts of income and capital taxes and the reasonableness of inter-company transfer prices, including interest charges, which could materially adversely affect cash positions of the Corporation or its subsidiaries, and holders of Debentures and the Common Shares.

Change of Tax Law

On July 18, 2017, the Minister of Finance (Canada) released for consultation a discussion paper seeking input on possible approaches to address certain perceived tax advantages of investing passively through a private corporation. Potential alternatives for amending the current system of corporate taxation under the Tax Act are outlined in this paper, although specific proposals to amend the Tax Act are not included. Legislative proposals are expected to be released by the Minister of Finance (Canada) following such consultation. There can be no assurance that, following the enactment of any such proposals, Securities held by a Canadian corporation will not be taxed under the Tax Act in a manner that is less favourable than under the current system.

Rights with respect to the Common Shares will arise only if and when the Corporation delivers Common Shares upon conversion of a Debenture

Holders of Debentures will not be entitled to any rights with respect to the Common Shares (including, without limitation, voting rights and rights to receive any dividends or other distributions on the Common Shares), but if a holder of Debentures subsequently converts its Debentures into Common Shares, such holder will be subject to all changes affecting the Common Shares. Rights with respect to the Common Shares will arise only if and when the Corporation delivers Common Shares upon conversion of a Debenture and, to a limited extent, under the conversion rate adjustments applicable to the Debentures. For example, in the event that an amendment is proposed to the Corporation's constating documents requiring shareholder approval and the record date for determining the shareholders of record entitled to vote on the amendment occurs prior to delivery of Common Shares to a holder, such holder will not be entitled to vote on the amendment, although such holder will nevertheless be subject to any changes in the powers or rights of Common Shares that result from such amendment.

EXEMPTIONS

On August 27, 2015, Hydro One Inc. obtained a decision from the Ontario Securities Commission, as principal regulator, on behalf of itself and the securities regulatory authorities in each of the other provinces and territories of Canada, exempting Hydro One Limited from the requirements in section 3.2 of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* which requires financial statements to be prepared in accordance with and disclosed in compliance with International Financial Reporting Standards. The decision granting the exemption permits Hydro One Limited to prepare and present its financial statements required to be filed with the securities regulatory authorities in each of the provinces and territories of Canada (including financial statements included in any prospectus of Hydro One Limited) in accordance with U.S. GAAP until the earliest to occur of the following:

(a) January 1, 2019;

(b) if Hydro One Limited ceases to have activities subject to rate regulation, the first day of Hydro One Limited's financial year commencing after its ceases to have such activities subject to rate regulation; and

(c) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

The exemption was requested: (i) due to continuing uncertainty of accounting treatment and lack of a specific mandatory standard for entities with activities subject to rate regulation under International Financial Reporting Standards; (ii) because U.S. GAAP provides a more suitable set of accounting principles for entities with activities subject to rate regulation and is more consistent with those prescribed by the Ontario Energy Board in its Accounting Procedures Handbook for Electric Distribution Utilities; and (iii) to ensure consistency with and comparability to the financial statements of Hydro One Inc. which reports in U.S. GAAP, as well as Hydro One Limited's industry peers that currently report in U.S. GAAP.

AUDITORS

KPMG LLP, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario, M5H 2S5, are the auditors of Hydro One Limited and have confirmed that they are independent of Hydro One Limited within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

The auditors of Avista Corporation are Deloitte & Touche LLP, in Seattle, Washington. Deloitte & Touche LLP is an independent registered public accounting firm that audited Avista Corporation's consolidated financial statements as at December 31, 2016 and December 31, 2015, and for each of the three years in the period ended December 31, 2016, included in this Prospectus.

LEGAL MATTERS

Certain legal matters relating to the Offering will be passed upon on behalf of the Corporation and the Selling Debentureholder by Osler, Hoskin & Harcourt LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP. At the date hereof, partners and associates of each of Osler, Hoskin & Harcourt LLP and Blake, Cassels & Graydon LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any associate or affiliate of the Corporation.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada at its principal office in Toronto, Ontario is the transfer agent and registrar for the Common Shares.

ENFORCEABILITY OF CERTAIN CIVIL LIABILITIES

Kathryn Jackson, a director of Hydro One Limited, resides outside of Canada. Ms. Jackson has appointed Hydro One Limited as her agent for service of process at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person who resides outside of Canada, even if the party has appointed an agent for service of process.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces and territories of Canada, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

Original purchasers of Debentures will have a contractual right of rescission against Hydro One Limited following the conversion of such Debentures in the event that this Prospectus or any amendment thereto contains a misrepresentation. The contractual right of rescission will entitle such original purchasers to receive from Hydro One Limited, upon surrender of the Common Shares issued upon conversion of such Debentures, the amount paid for such Debentures, provided that the right of rescission is exercised within 180 days from the date of the purchase of such Debentures under this Prospectus.

In an offering of Debentures represented by Instalment Receipts, investors are cautioned that the statutory right of action for damages for a misrepresentation contained in this Prospectus is limited, in certain provincial and territorial securities legislation, to the price at which the Debentures represented by Instalment Receipts are offered to the public under the prospectus offering. This means that, under the securities legislation of certain provinces and territories, if the purchaser pays additional amounts upon conversion of the security, those amounts may not be recoverable under the statutory right of action for damages that applies in those provinces and territories. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of this right of action for damages or consult with a legal adviser.

PROMOTERS

Hydro One Inc. has taken the initiative in founding and organizing Hydro One Limited and may therefore be considered a promoter of Hydro One Limited for the purposes of applicable securities legislation. In connection with a series of pre-closing transactions completed in connection with the initial public offering of Hydro One Limited, on October 31, 2015, Hydro One Limited acquired all of the issued and outstanding common shares of Hydro One Inc. from the Province in exchange for the issuance to the Province of 16,720,000 Series 1 Preferred Shares and 12,197,500,000 Common Shares. For further details concerning the relationship between Hydro One Limited and Hydro One Inc., see the documents incorporated by reference in this Prospectus.

GLOSSARY OF TERMS

In this Prospectus, unless the context otherwise requires, the following terms have the meanings set forth below.

"**1933 Act**" has the meaning ascribed thereto under the heading "Plan of Distribution".

"**2016 Annual Financial Statements**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Adjusted EPS**" means adjusted earnings per common share.

"**Adverse Recommendation Change**" has the meaning ascribed thereto under the heading "The Merger Agreement – No Solicitation; Avista Corporation's Board of Directors Recommendation".

"**AEL&P**" means Alaska Electric Light and Power Company.

"**AERC**" means Alaska Energy and Resources Company.

"**AFUDC**" means allowance for funds used during construction and represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator.

"**AIDEA"** means Alaska Industrial Development and Export Authority.

"**AIF**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**AM&D**" means Advanced Manufacturing and Development, doing business as METALfx.

"**AMI**" has the meaning ascribed thereto under the heading "Risk Factors – Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corp".

"**Annual MD&A**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Approval Conditions**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**ARO**" means asset retirement obligation.

"**Avista Corp.**" means Avista Corporation and its subsidiaries, and references to individual subsidiaries of Avista Corporation refer to that company and its respective subsidiaries.

"**Avista Material Adverse Effect**" means any circumstance, development, change, event, occurrence or effect that:

(a) has, individually or in the aggregate, a material adverse effect on the business, assets, properties, results of operations or financial condition of Avista Corporation and its subsidiaries taken as a whole; provided that none of the following shall constitute or be taken into account in determining whether an Avista Material Adverse Effect has occurred: (i) any circumstance, development, change, event, occurrence or effect in any of the industries or markets in which Avista Corporation or its subsidiaries operates, including electric generation, transmission or distribution or natural gas distribution or transmission industries (including, in each case, any changes in the operations thereof or with respect to system-wide changes or developments in electric generation, transmission, or distribution or natural gas distribution or transmission systems); (ii) any enactment of, change in, or change in interpretation of, any law or U.S. GAAP or governmental policy; (iii) general economic, regulatory or political conditions (or changes therein) or conditions (or changes therein) in the financial, credit or securities markets (including changes in interest or currency exchange rates) in any country or region in which Avista Corporation or any of its subsidiaries conducts business; (iv) any changes or developments in wholesale or retail electric power prices or any change in the price of natural gas or any other raw material, mineral or commodity used or sold by Avista Corporation or any of its subsidiaries or in the cost of hedges relating to such prices, any change in the price of interstate electricity or natural gas transportation services or any change in customer usage patterns or customer selection of third-party suppliers for natural gas or electricity; (v) any acts of God, natural disasters, terrorism, armed hostilities, sabotage, war or any escalation or worsening of acts of terrorism, armed hostilities or war; (vi) the announcement, pendency of or performance of the Merger and the related transactions contemplated by the Merger Agreement, including by reason of the identity of the Corporation or any communication by the Corporation regarding the plans or intentions of the Corporation with respect to the conduct of the business of Avista Corporation or its subsidiaries and including the impact of any of the foregoing on any relationships with customers, suppliers, distributors, collaboration partners, joint venture partners, employees or regulators; (vii) any action taken by Avista Corporation or any of its subsidiaries that is required or permitted by the terms of the Merger Agreement or with the consent or at the direction of the Corporation or Merger Sub (or any action not taken as a result of the failure of the Corporation to consent to any action requiring the Corporation's consent pursuant to Section 5.1 of the Merger Agreement); (viii) any change in the market price, or change in trading volume, of the capital stock of Avista Corporation (but not the underlying circumstances giving rise to such change); (ix) any failure by Avista Corporation or its subsidiaries to meet earnings estimates or financial projections or forecasts for any period, or any changes in credit ratings and any changes in any analysts recommendations or ratings with respect to Avista Corporation or any of its subsidiaries (but not the underlying circumstances giving rise to the failure if not otherwise falling within any of the exceptions set forth in clauses (i)-(viii) or (x)-(xii) above and below); (x) any change or effect arising from any rate cases directly related to Avista Corporation or its subsidiaries; (xi) any circumstance, development, change, event, occurrence or effect that results from any shutdown or suspension of operations at any third-party facilities (including with respect to electricity and power plants) from which Avista Corporation or any of its subsidiaries obtains natural gas or electricity and (xii) any pending, initiated or threatened litigation relating to the Merger, in the case of each of clauses (i) through (v), to the extent that such circumstance, development, change, event, occurrence or effect does not affect Avista Corporation and its subsidiaries, taken as a whole, in a materially disproportionate manner relative to other similarly situated participants in the business and industries in which Avista Corporation and its subsidiaries operate; or

(b) would, individually or in the aggregate, reasonably be expected to prevent or materially impede, interfere with or delay the consummation by Avista Corporation of the Merger and related transactions contemplated by the Merger Agreement.

"**Avista Intervening Event**" has the meaning ascribed thereto under the heading "The Merger Agreement – No Solicitation; Avista Corporation's Board of Directors Recommendation".

"**Avista Shareholder Approval**" has the meaning ascribed thereto under the heading "The Merger Agreement – Closing Conditions".

"**Avista Shareholders Meeting**" has the meaning ascribed thereto under the heading "The Merger Agreement – Termination".

"**Avista Termination Fee**" has the meaning ascribed thereto under the heading "The Merger Agreement – Termination".

"**Avista Utilities**" means the operating division of Avista Corporation (not a subsidiary) comprising the regulated utility operations in the Pacific Northwest.

"**BART**" means Best Available Retrofit Technology.

"**Board of Directors**" means the board of directors of Hydro One Limited.

"**Book-Entry Only System**" has the meaning ascribed thereto under the heading "Details of the Offering – Instalment Receipts – Book-Entry Only System".

"**Boulder Park GS**" has the meaning ascribed thereto under the heading "The Acquired Business – Avista Utilities".

"**BPA**" means Bonneville Power Administration.

"**Burdensome Condition**" means any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including any Remedial Action (as defined in the Merger Agreement)) that, in the aggregate, would have or would be reasonably likely to have, a material adverse effect on the financial condition, businesses or results of operations of Avista Corporation and its subsidiaries, taken as a whole, or of the Corporation and its subsidiaries, taken as a whole and after giving effect to the Merger; provided that, for this purpose, the Corporation and its subsidiaries (including Avista Corporation and its subsidiaries) shall be deemed to be a consolidated group of entities of the size and scale of a hypothetical company that is 100% of the size and scale of Avista Corporation and its subsidiaries, taken as a whole as of immediately prior to the Effective Time (as defined in the Merger Agreement); and provided, further, that the undertakings, terms, conditions, liabilities, obligations, commitments or sanctions described in Section 1.6(a), Section 1.7 and Exhibit B of the Merger Agreement shall not constitute or be taken into account in determining whether there has been or is such a material adverse effect.

"**CAA**" means the *Clean Air Act*.

"**Cabinet Gorge**" means the Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho.

"**California Parties**" means, together, Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, the California Attorney General, the California Department of Water Resources, and the California Public Utilities Commission.

"**Canadian Securities Regulators**" means the applicable securities commission or securities regulatory authority in each of the provinces and territories of Canada.

"**CAR**" means the Clean Air Rule.

"**CCRs**" means coal combustion residuals.

"**Cdn$**" means the lawful currency of Canada.

"**CDM**" means conversation and demand management.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**CDS Participant**" means a participant in CDS.

"**CFIUS**" means the Committee on Foreign Investment in the United States.

"**CFSA**" means the Clark Fork Settlement Agreement.

"**Closing Date**" means the closing of the Offering, which is expected to take place on or about August 9, 2017.

"**CO2**" means carbon dioxide.

"**Colstrip**" means the coal-fired Colstrip Generating Plant in southeastern Montana.

"**Commerce**" means the Washington State Department of Commerce.

"**Common Shares**" means the common shares in the capital of Hydro One Limited.

"**Complaint**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**Conversion Price**" means $21.40 per Common Share, being a conversion rate of 46.7290 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

"**Corporation**" means Hydro One Limited.

“**Corporation Material Adverse Effect**” means any change, circumstance, development, event, occurrence or effect that, individually or in the aggregate, has had or would reasonably be expected to have a material and adverse effect on the ability of the Corporation, US Parent or Merger Sub to consummate, or that would reasonably be expected to prevent or materially impede, interfere with or delay the consummation by the Corporation, US Parent or Merger Sub, of the Merger and the related transactions contemplated by the Merger Agreement.

“**Corporation Termination Fee**” has the meaning ascribed thereto under the heading “The Merger Agreement – Termination”.

“**Counsel**” has the meaning ascribed thereto under the heading “Certain Canadian Federal Income Tax Considerations”.

“**Coyote Springs 2**” means the natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon.

“**CT**” means combustion turbine.

“**Custodian**” has the meaning ascribed thereto under the heading “Details of the Offering – Instalment Receipts”.

“**DBRS**” means DBRS Limited.

“**D.C. Circuit**” has the meaning ascribed thereto under the heading “The Acquired Business – Environmental Issues and Contingencies”.

“**DPSP**” means a deferred profit sharing plan as defined in the Tax Act.

“**Debentures**” means 4.00% convertible unsecured subordinated debentures of Hydro One Limited offered pursuant to this Prospectus.

“**Defaulting Holder**” has the meaning ascribed thereto under the heading “Details of the Offering – Instalment Receipts”.

“**Ecology**” means the Washington State Department of Ecology.

“**Ecova**” means Ecova, Inc., a provider of facility information and cost management services for multi-site customers and energy efficiency program management for commercial enterprises and utilities throughout North America, subsidiary of Avista Capital. Ecova was sold on June 30, 2014.

“**EGUs**” has the meaning ascribed thereto under the heading “The Acquired Business – Environmental Issues and Contingencies”.

“**EIA**” means the *Energy Independence Act*.

“**End Date**” means September 30, 2018.

“**EPA**” means the United States Environmental Protection Agency.

“**ERM**” means the Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington.

“**ERU**” means Emission Reduction Units.

“**ESA**” means the *Federal Endangered Species Act*.

“**Exempt Plans**” has the meaning ascribed thereto under the heading “Eligibility for Investment”.

“**FCA**” means Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho.

“**FCC**” means the United States Federal Communications Commission.

"**Federal Tax Regime**" has the meaning ascribed thereto under the heading "Presentation of Financial Information – Funds from Operations and Adjusted FFO".

"**FERC**" means the United States Federal Energy Regulatory Commission.

"**FFO**" has the meaning ascribed thereto under the heading "Presentation of Financial Information – Funds from Operations and Adjusted FFO".

"**Final CPP**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**Final CPS**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies"

"**Final Instalment Date**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**Final Instalment Notice**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**Final Order**" means a Judgment by the relevant Governmental Authority that (i) is not then reversed, stayed, enjoined, set aside, annulled or suspended and is in full force and effect, (ii) with respect to which, if applicable, any mandatory waiting period prescribed by law applicable to such Judgment before the Merger may be consummated has expired or been terminated, and (iii) as to which all conditions precedent to the closing of the Merger expressly set forth in such Judgment have been satisfied.

"**FIP**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**FPA**" means the *Federal Power Act*.

"**GHG**" means greenhouse gas.

"**Governance Agreement**" means the Governance Agreement dated November 5, 2015 between Hydro One Limited and the Province.

"**HAPs**" means hazardous air pollutants.

"**Holder**" has the meaning ascribed thereto under the heading "Certain Canadian Federal Income Tax Considerations".

"**HSR Act**" means the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, as amended.

"**Hydro One**" means Hydro One Limited and its subsidiaries taken together as a whole.

"**Hydro One Limited**" means Hydro One Limited.

"**I-732**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**ICNU**" means the Industrial Customers of Northwest Utilities.

"**Indenture**" has the meaning ascribed thereto under the heading "Details of the Offering – Debentures".

"**Instalment Receipt Agreement**" has the meaning ascribed thereto under the heading "Details of the Offering – Instalment Receipts".

"**Instalment Receipts**" means the instalment receipts representing beneficial ownership of the Debentures.

"**Interim Financial Statements**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Interim MD&A**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Intervening Event**" has the meaning ascribed thereto under the heading "The Merger Agreement – No Solicitation; Avista Corporation's Board of Directors Recommendation".

"**Investor Presentation**" has the meaning ascribed thereto under the heading "Marketing Materials".

"**IPO**" means the initial public offering of Hydro One Limited on November 5, 2015.

"**IPUC**" means the Idaho Public Utilities Commission.

"**IT**" means information technology.

"**Jackson Prairie**" means Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington.

"**Judgment**" means a judgment, injunction, order, decree, ruling, writ, assessment or arbitration award of a Governmental Authority of competent jurisdiction.

"**Kettle Falls CT**" has the meaning ascribed thereto under the heading "The Acquired Business – Avista Utilities".

"**Kettle Falls GS**" has the meaning ascribed thereto under the heading "The Acquired Business – Avista Utilities".

"**KV**" means kilovolt.

"**KW**" means kilowatt.

"**Lancaster Plant**" means a natural gas-fired combined cycle combustion turbine plant located in Idaho.

"**Legislature**" means the Washington State Legislature.

"**Little Falls**" means the Little Falls Hydroelectric Generating Project.

"**LNG**" means Liquefied Natural Gas.

"**Make-Whole Payment**" has the meaning ascribed thereto under the heading "The Offering – Interest".

"**Marketing Materials**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Market Price**" means the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the Maturity Date.

"**MATS**" means the Mercury Air Toxic Standards.

"**Maturity Date**" means September 30, 2027.

"**Merger**" means the direct or indirect acquisition by US Parent of Avista Corporation pursuant to the terms of the Merger Agreement.

"**Merger Agreement**" means the Agreement and Plan of Merger dated as of July 19, 2017 among the Corporation, US Parent, Merger Sub and Avista Corporation.

"**Merger Consideration**" has the meaning ascribed thereto under the heading "The Merger Agreement – The Merger Consideration".

"**Merger-Related Expenses**" means the estimated non-recurring costs, including related income tax effects and any governmental and other imposed costs that may be incurred to consummate the Merger. Such costs, which will be fully expensed when incurred in accordance with U.S. GAAP, include but are not limited to fees associated with financial advisory, consulting, accounting, tax, legal and other professional services, costs associated with change of control and integration, out-of-pocket costs and other costs of a non-recurring nature.

"**Merger Sub**" means Olympus Corp., a direct wholly-owned subsidiary of US Parent and, at the effective time of the closing of the Merger, will be collectively owned by US Parent and one or more direct or indirect wholly-owned subsidiaries of the Corporation.

"**Moody's**" means Moody's Investors Service, Inc.

"**MPSC**" means the Public Service Commission of the State of Montana.

"**MW**" means megawatts.

"**MWh**" means megawatt-hours.

"**NERC**" means the North American Electric Reliability Corporation.

"**Northeast CT**" has the meaning ascribed thereto under the heading "The Acquired Business – Avista Utilities".

"**Noxon Rapids**" means the Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana.

"**NSPS**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**NYSE**" means the New York Stock Exchange.

"**OBCA**" means the *Business Corporations Act* (Ontario).

"**Offering**" means the offering of Debentures represented by Instalment Receipts pursuant to this Prospectus.

"**Offering Price**" has the meaning ascribed thereto under the heading "Plan of Distribution".

"**Operating Credit Facility**" has the meaning ascribed thereto under the heading "Financing the Merger".

"**OPUC**" means the Public Utility Commission of Oregon.

"**Order 05**" has the meaning ascribed thereto under the heading "The Acquired Business – Regulation and Regulatory Matters".

"**Order 06**" has the meaning ascribed thereto under the heading "The Acquired Business – Regulation and Regulatory Matters".

"**Over-Allotment Option**" means an option to purchase additional Debentures represented by Instalment Receipts equal to up to 10% of the aggregate principal amount of Debentures, as more fully described on the cover page.

"**PC**" means the Public Counsel Unit of the Washington State Office of the Attorney General.

"**Petition**" has the meaning ascribed thereto under the heading "The Acquired Business – Regulation and Regulatory Matters".

"**Petitioners**" means, collectively, Avista Corp., Cascade Natural Gas Corp., NW Natural and PSE.

"**PGA**" means purchased gas adjustment.

"**PILs**" has the meaning ascribed thereto under the heading "Presentation of Financial Information – Funds from Operations and Adjusted FFO".

"**PILs Regime**" has the meaning ascribed thereto under the heading "Presentation of Financial Information – Funds from Operations and Adjusted FFO".

"**PPA**" means a power purchase agreement.

"**Proceeding**" has the meaning ascribed thereto under the heading "Plan of Distribution".

"**Proposed Amendments**" has the meaning ascribed thereto under the heading "Certain Canadian Federal Income Tax Considerations".

"**Prospectus**" means this short form prospectus dated August 1, 2017.

"**Province**" means Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy.

"**PSE**" means Puget Sound Energy.

"**PSUs**" means performance share units.

"**PUD**" means Public Utility District.

"**PURPA**" means the Public Utility Regulatory Policies Act of 1978, as amended.

"**Rathdrum CT**" has the meaning ascribed thereto under the heading "The Acquired Business – Avista Utilities".

"**RCA**" means the Regulatory Commission of Alaska.

"**RDSP**" means a registered disability savings plan as defined in the Tax Act.

"**Representatives**" has the meaning ascribed thereto under the heading "The Merger Agreement – No Solicitation; Avista Corporation's Board of Directors Recommendation".

"**RESP**" means a registered education savings plan as defined in the Tax Act.

"**Restraint**" has the meaning ascribed thereto under the heading "The Merger Agreement – Termination".

"**Revolving Credit Facility**" has the meaning ascribed thereto under the heading "Relationships between Hydro One Limited, the Selling Debentureholder and Certain Underwriters."

"**ROE**" means return on equity.

"**ROR**" means rate of return.

"**RRIF**" means a registered retirement income fund as defined in the Tax Act.

"**RRSP**" means a registered retirement savings plan as defined in the Tax Act.

"**RSUs**" has the meaning ascribed thereto under the heading "The Merger Agreement – The Merger Consideration".

"**S&P**" means Standard & Poor's Ratings Services.

"**Salix**" means Salix, Inc., a subsidiary of Avista Capital, launched in 2014 to explore markets that could be served with LNG, primarily in western North America.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**Securities**" has the meaning ascribed thereto under the heading "Certain Canadian Federal Income Tax Considerations".

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

“**Selling Debentureholder**” means 2587264 Ontario Inc., a direct wholly-owned subsidiary of Hydro One Limited.

“**Senior Indebtedness**” has the meaning ascribed thereto under the heading “Details of the Offering – Debentures – Subordination”.

“**Series 1 Preferred Shares**” means the Series 1 preferred shares in the capital of Hydro One Limited.

“**Series 2 Preferred Shares**” means the Series 2 preferred shares in the capital of Hydro One Limited.

“**Subsidiary Board**” has the meaning ascribed thereto under the heading “The Merger Agreement – Covenants”.

“**Superior Proposal**” means any unsolicited written Takeover Proposal on terms which the board of directors of Avista Corporation (or a duly authorized committee thereof) determines in good faith, after consultation with Avista Corporation’s outside legal counsel and independent financial advisors, to be more favourable to the holders of Avista Corporation common stock than the Merger (as may be revised in accordance with the terms of the Merger Agreement), taking into account, to the extent applicable, the legal, financial, regulatory and other aspects of such proposal and the Merger Agreement that the board of directors of Avista Corporation considers relevant, including the prospects for receipt of any required regulatory approvals and taking into account the operational and governance commitments made by the Corporation in the Merger Agreement; provided that for purposes of the definition of “Superior Proposal”, the references to “15%” in the definition of Takeover Proposal shall be deemed to be references to “50%.”

“**Takeover Proposal**” means any bona fide inquiry, proposal or offer from any Person (other than the Corporation, US Parent, Merger Sub or any of their respective affiliates) to purchase or otherwise acquire, directly or indirectly, in a single transaction or series of related transactions, (i) assets of Avista Corporation and its subsidiaries (including securities of subsidiaries) that account for 15% or more of Avista Corporation’s consolidated assets or from which 15% or more of Avista Corporation’s revenues or earnings on a consolidated basis are derived or (ii) 15% or more of the outstanding Avista Corporation common stock pursuant to a merger, consolidation or other business combination, sale or issuance of shares of capital stock, tender offer, share exchange, recapitalization or similar transaction involving Avista Corporation, in each case other than the Merger.

“**Tax Act**” means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time.

“**TFSA**” means a tax-free savings account as defined in the Tax Act.

“**Total Dissolved Gas**” or **TDG**” has the meaning ascribed thereto under the heading “The Acquired Business – Legal Proceedings”.

“**Trustee**” has the meaning ascribed thereto under the heading “Details of the Offering – Debentures”.

“**TSX**” means the Toronto Stock Exchange.

“**U.S.**” means the United States.

“**U.S. dollars**” or “**US$**” means the lawful currency of the U.S.

“**U.S. GAAP**” means United States Generally Accepted Accounting Principles.

“**Underwriters**” means, collectively, RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., Barclays Capital Canada Inc., Credit Suisse Securities (Canada), Inc., Canaccord Genuity Corp., Desjardins Securities Inc., Laurentian Bank Securities Inc., Raymond James Ltd., Industrial Alliance Securities Inc. and Wells Fargo Securities Canada, Ltd.

“**Underwriting Agreement**” has the meaning ascribed thereto under the heading “Plan of Distribution”.

“**USFWS**” means the United States Fish and Wildlife Service.

"**utility boilers and IGCC units**" has the meaning ascribed thereto under the heading "The Acquired Business – Environmental Issues and Contingencies".

"**US Parent**" means Olympus Holding Corp., an indirect, wholly-owned subsidiary of the Corporation.

"**WECC**" means the Western Electricity Coordinating Council.

"**WUTC**" means the Washington Utilities and Transportation Commission.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Avista Corporation

Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 21, 2017

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31

Dollars in thousands, except per share amounts

	2016	2015	2014
Operating Revenues:			
Utility revenues	$ 1,418,914	$ 1,456,091	$ 1,433,343
Non-utility revenues	23,569	28,685	39,219
Total operating revenues	1,442,483	1,484,776	1,472,562
Operating Expenses:			
Utility operating expenses:			
Resource costs	551,366	656,964	678,244
Other operating expenses	315,795	303,221	286,832
Depreciation and amortization	160,514	143,499	129,570
Taxes other than income taxes	98,735	97,657	94,300
Non-utility operating expenses:			
Other operating expenses	25,501	29,526	30,418
Depreciation and amortization	769	695	610
Total operating expenses	1,152,680	1,231,562	1,219,974
Income from operations	289,803	253,214	252,588
Interest expense	86,496	79,968	75,302
Interest expense to affiliated trusts	634	473	450
Capitalized interest	(2,651)	(3,546)	(3,924)
Other income-net	(10,078)	(9,300)	(11,346)
Income from continuing operations before income taxes	215,402	185,619	192,106
Income tax expense	78,086	67,449	72,240
Net income from continuing operations	137,316	118,170	119,866
Net income from discontinued operations (Note 5)	—	5,147	72,411
Net income	137,316	123,317	192,277
Net income attributable to noncontrolling interests	(88)	(90)	(236)
Net income attributable to Avista Corp. shareholders	$ 137,228	$ 123,227	$ 192,041

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

For the Years Ended December 31

Dollars in thousands, except per share amounts

	2016	2015	2014
Amounts attributable to Avista Corp. shareholders:			
Net income from continuing operations	$ 137,228	$ 118,080	$ 119,817
Net income from discontinued operations	—	5,147	72,224
Net income attributable to Avista Corp. shareholders	$ 137,228	$ 123,227	$ 192,041
Weighted-average common shares outstanding (thousands), basic	63,508	62,301	61,632
Weighted-average common shares outstanding (thousands), diluted	63,920	62,708	61,887
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 2.16	$ 1.90	$ 1.94
Earnings per common share from discontinued operations	—	0.08	1.18
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 2.16	$ 1.98	$ 3.12
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 2.15	$ 1.89	$ 1.93
Earnings per common share from discontinued operations	—	0.08	1.17
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 2.15	$ 1.97	$ 3.10
Dividends declared per common share	$ 1.37	$ 1.32	$ 1.27

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2016	2015	2014
Net income	$ 137,316	$ 123,317	$ 192,277
Other Comprehensive Income (Loss):			
Unrealized investment gains - net of taxes of $0, $0 and $664, respectively	—	—	1,126
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $0, $0 and $(1), respectively	—	—	(2)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $0, $0 and $273, respectively	—	—	462
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $(495), $667 and $(1,967), respectively	(918)	1,238	(3,655)
Total other comprehensive income (loss)	(918)	1,238	(2,069)
Comprehensive income	136,398	124,555	190,208
Comprehensive income attributable to noncontrolling interests	(88)	(90)	(236)
Comprehensive income attributable to Avista Corporation shareholders	$ 136,310	$ 124,465	$ 189,972

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31

Dollars in thousands

	2016	2015
Assets:		
Current Assets:		
Cash and cash equivalents	$ 8,507	$ 10,484
Accounts and notes receivable-less allowances of $5,026 and $4,530, respectively	180,265	169,413
Regulatory asset for energy commodity derivatives	11,365	17,260
Materials and supplies, fuel stock and stored natural gas	53,314	54,148
Income taxes receivable	48,265	24,121
Other current assets	49,625	30,620
Total current assets	351,341	306,046
Net Utility Property:		
Utility plant in service	5,506,499	5,129,192
Construction work in progress	150,474	202,683
Total	5,656,973	5,331,875
Less: Accumulated depreciation and amortization	1,509,473	1,433,286
Total net utility property	4,147,500	3,898,589
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Long-term energy contract receivable	—	14,694
Other property and investments-net and other non-current assets	72,224	59,733
Total other non-current assets	141,443	143,646
Deferred Charges:		
Regulatory assets for deferred income tax	109,853	101,240
Regulatory assets for pensions and other postretirement benefits	240,114	235,009
Other regulatory assets	135,751	99,798
Regulatory asset for interest rate swaps	161,508	83,973
Non-current regulatory asset for energy commodity derivatives	16,919	32,420
Other deferred charges	5,326	5,928
Total deferred charges	669,471	558,368
Total assets	$ 5,309,755	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

As of December 31

Dollars in thousands

	2016	2015
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 115,545	$ 114,349
Current portion of long-term debt and capital leases	3,287	93,167
Short-term borrowings	120,000	105,000
Energy commodity derivative liabilities	7,035	14,268
Accrued interest	15,869	15,378
Accrued taxes other than income taxes	33,374	30,978
Deferred natural gas costs	30,820	17,880
Current portion of pensions and other postretirement benefits	10,994	10,233
Other current liabilities	70,604	73,427
Total current liabilities	407,528	474,680
Long-term debt and capital leases	1,678,717	1,480,111
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	273,983	261,594
Pensions and other postretirement benefits	226,552	201,453
Deferred income taxes	840,928	747,477
Non-current interest rate swap derivative liabilities	28,705	30,679
Other non-current liabilities, regulatory liabilities and deferred credits	153,319	130,821
Total liabilities	3,661,279	3,378,362
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 64,187,934 and 62,312,651 shares issued and outstanding as of December 31, 2016 and December 31, 2015, respectively	1,075,281	1,004,336
Accumulated other comprehensive loss	(7,568)	(6,650)
Retained earnings	581,014	530,940
Total Avista Corporation shareholders' equity	1,648,727	1,528,626
Noncontrolling Interests	(251)	(339)
Total equity	1,648,476	1,528,287
Total liabilities and equity	$ 5,309,755	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2016	2015	2014
Operating Activities:			
Net income	$ 137,316	$ 123,317	$ 192,277
Non-cash items included in net income:			
Depreciation and amortization	164,925	147,835	138,337
Provision for deferred income taxes	124,543	51,801	144,269
Power and natural gas cost amortizations (deferrals), net	16,835	21,358	(14,821)
Amortization of debt expense	3,477	3,526	3,692
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	7,891	6,914	8,114
Equity-related AFUDC	(8,475)	(8,331)	(8,808)
Pension and other postretirement benefit expense	38,786	37,050	22,943
Amortization of Spokane Energy contract	14,694	13,508	12,417
Gain on sale of Ecova	—	(777)	(160,612)
Other regulatory assets and liabilities and deferred debits and credits	(26,245)	4,569	7,906
Change in decoupling regulatory deferral	(29,789)	(10,933)	—
Other	5,557	(517)	1,103
Contributions to defined benefit pension plan	(12,000)	(12,000)	(32,000)
Cash paid for settlement of interest rate swap derivatives	(53,966)	—	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(17,170)	(10,538)	16,425
Materials and supplies, fuel stock and stored natural gas	834	12,208	(19,394)
Collateral posted for derivative instruments	10,712	(13,301)	(23,301)
Income taxes receivable	(33,923)	19,772	(36,110)
Other current assets	(3,907)	2,338	(7,117)
Accounts payable	5,176	(8,138)	(12,562)
Other current liabilities	10,546	(6,471)	32,060
Net cash provided by operating activities	358,267	375,640	267,268
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(406,644)	(393,425)	(325,516)
Other capital expenditures	(353)	(885)	(6,427)
Cash received (paid) in acquisition, net	—	(95)	15,007
Issuance of notes receivable at subsidiaries	(10,094)	(2,307)	(1,200)
Repayments from notes receivable at subsidiaries	5,000	—	—
Investments made by subsidiaries	(13,097)	(1,944)	(1,072)
Increase in funds held for clients	—	—	(18,931)
Purchase of securities available for sale	—	—	(12,267)
Sale and maturity of securities available for sale	—	—	14,612
Proceeds from sale of Ecova, net of cash sold	—	13,856	229,903
Other	(7,278)	(3,027)	2,155
Net cash used in investing activities	$ (432,466)	$ (387,827)	$ (103,736)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2016	2015	2014
Financing Activities:			
Net increase (decrease) in borrowings from committed line of credit	$ 15,000	$ —	$ (66,000)
Repayment of borrowings from Ecova line of credit	—	—	(46,000)
Proceeds from issuance of long-term debt	245,000	100,000	150,000
Redemption and maturity of long-term debt and capital leases	(163,167)	(2,905)	(39,971)
Maturity of nonrecourse long-term debt of Spokane Energy	—	(1,431)	(16,407)
Issuance of common stock, net of issuance costs	66,953	1,560	4,060
Repurchase of common stock	—	(2,920)	(79,856)
Cash dividends paid	(87,154)	(82,397)	(78,314)
Increase in client fund obligations	—	—	16,216
Payment to noncontrolling interests for sale of Ecova	—	—	(54,179)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	—	(20,871)
Other	(4,410)	(11,379)	7,359
Net cash provided by (used in) financing activities	72,222	528	(223,963)
Net decrease in cash and cash equivalents	(1,977)	(11,659)	(60,431)
Cash and cash equivalents at beginning of year	10,484	22,143	82,574
Cash and cash equivalents at end of year	$ 8,507	$ 10,484	$ 22,143
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 86,319	$ 79,673	$ 73,526
Income taxes (net of total refunds of $18,861, $37,200 and $35,573, respectively)	(13,458)	(9,961)	45,416
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	30,252	35,248	26,959
Valuation adjustment for redeemable noncontrolling interests	—	—	(15,873)
Receivable for escrow amounts associated with the sale of Ecova	—	—	13,079
Non-cash stock issuance for acquisition of AERC	—	—	150,119

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2016	2015	2014
Common Stock, Shares:			
Shares outstanding at beginning of year	62,312,651	62,243,374	60,076,752
Shares issued through equity compensation plans	203,727	125,620	51,127
Shares issued through Employee Investment Plan (401-K)	26,556	33,057	33,168
Shares issued through Dividend Reinvestment Plan	—	—	110,501
Shares issued through sales agency agreements	1,645,000	—	—
Shares issued for acquisition	—	—	4,501,441
Shares repurchased	—	(89,400)	(2,529,615)
Shares outstanding at end of year	64,187,934	62,312,651	62,243,374
Common Stock, Amount:			
Balance at beginning of year	$ 1,004,336	$ 999,960	$ 896,993
Equity compensation expense	7,065	6,035	7,676
Issuance of common stock through equity compensation plans	624	462	108
Issuance of common stock through Employee Investment Plan (401-K)	1,061	1,099	1,005
Issuance of common stock through Dividend Reinvestment Plan	—	—	3,441
Issuance of common stock through sales agency agreements, net of issuance costs	65,267	—	—
Issuance of common stock for acquisition, net of issuance costs	—	—	149,625
Payment of minimum tax withholdings for share-based payment awards	(3,072)	(1,832)	—
Repurchase of common stock	—	(1,431)	(40,486)
Equity transactions of consolidated subsidiaries	—	—	(1,062)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	—	(20,871)
Excess tax benefits	—	43	3,531
Balance at end of year	1,075,281	1,004,336	999,960
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(6,650)	(7,888)	(5,819)
Other comprehensive income (loss)	(918)	1,238	(2,069)
Balance at end of year	(7,568)	(6,650)	(7,888)
Retained Earnings:			
Balance at beginning of year	530,940	491,599	407,092
Net income attributable to Avista Corporation shareholders	137,228	123,227	192,041
Cash dividends paid (common stock)	(87,154)	(82,397)	(78,314)
Repurchase of common stock	—	(1,489)	(39,370)
Valuation adjustments and other noncontrolling interests activity	—	—	10,150
Balance at end of year	581,014	530,940	491,599
Total Avista Corporation shareholders' equity	$ 1,648,727	$ 1,528,626	$ 1,483,671

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS (continued)

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2016	2015	2014
Noncontrolling Interests:			
Balance at beginning of year	$ (339)	$ (429)	$ 20,001
Net income attributable to noncontrolling interests	88	90	240
Deconsolidation of noncontrolling interests related to sale of Ecova	—	—	(23,612)
Other	—	—	2,942
Balance at end of year	(251)	(339)	(429)
Total equity	$ 1,648,476	$ 1,528,287	$ 1,483,242
Redeemable Noncontrolling Interests:			
Balance at beginning of year	$ —	$ —	$ 15,889
Net income attributable to noncontrolling interests	—	—	(4)
Purchase of subsidiary noncontrolling interests	—	—	(12)
Valuation adjustments and other noncontrolling interests activity	—	—	(15,873)
Balance at end of year	$ —	$ —	$ —

The Accompanying Notes are an Integral Part of These Statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is AEL&P, which comprises Avista Corp.'s regulated utility operations in Alaska. AERC was acquired by Avista Corp. on July 1, 2014 and there are no AERC earnings included in the overall results of Avista Corp. prior to that date. See Note 4 for information regarding the acquisition of AERC.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, which is a subsidiary of AERC. During the first half of 2014 and prior, Avista Capital’s subsidiaries included Ecova, which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. See Note 5 for information regarding the disposition of Ecova and Note 21 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Ecova's revenues and expenses are included in the Consolidated Statements of Income in discontinued operations; however, as of June 30, 2014 and for all subsequent reporting periods there are no balance sheet amounts included for Ecova. All tables throughout the Notes to Consolidated Financial Statements that present information related to the Consolidated Statements of Income were revised to include only the amounts from continuing operations. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for 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 during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing,
- recoverability of regulatory assets, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the FERC and adopted by the state regulatory commissions in Washington, Idaho, Montana, Oregon and Alaska.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is also subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Utility Revenues

Utility revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. Revenues and resource costs from Avista Utilities' settled energy contracts that are "booked out" (not physically delivered) are reported on a net basis as part of utility revenues. AEL&P does not have booked out transactions. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Our estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in thousands):

	2016	2015
Unbilled accounts receivable	$ 72,377	$ 62,003

Other Non-Utility Revenues

Revenues from the other businesses are primarily derived from the operations of AM&D, doing business as METALfx, and are recognized when the risk of loss transfers to the customer, which occurs when products are shipped. In addition, prior to Spokane Energy's dissolution in 2015, there were revenues at Spokane Energy related to a long-term fixed rate electric capacity contract. This contract was transferred to Avista Corp. during the second quarter of 2015 and the revenues from this contract subsequent to the transfer are included in utility revenues.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2016	2015	2014
Avista Utilities			
Ratio of depreciation to average depreciable property	3.11%	3.09%	2.97%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.39%	2.42%	2.43%

The average service lives for the following broad categories of utility plant in service are (in years):

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	41	41
Hydroelectric production	78	42
Electric transmission	57	41
Electric distribution	35	40
Natural gas distribution property	45	N/A
Other shorter-lived general plant	9	15

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Utility related taxes	$ 57,745	$ 59,173	$ 58,250
Property taxes	38,505	35,948	33,932
Other taxes	2,485	2,536	2,118
Total	$ 98,735	$ 97,657	$ 94,300

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Consolidated Statements of Income in the line item “capitalized interest.” The equity component of AFUDC is included in the Consolidated Statement of Income in the line item “other income-net.” The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2016	2015	2014
Avista Utilities			
Effective AFUDC rate	7.29%	7.32%	7.64%
Alaska Electric Light and Power Company			
Effective AFUDC rate	9.40%	9.31%	10.37%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes (such as depreciation). A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company’s consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers. The Company did not incur any penalties on income tax positions in 2016, 2015 or 2014. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company’s financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Stock-based compensation expense	$ 7,891	$ 6,914	$ 6,007
Income tax benefits (1)	4,359	2,420	2,102

(1) Income tax benefits for 2016 include $1.6 million associated with excess tax benefits on settled share-based employee payments. The excess tax benefits were recognized in the Statement of Income for 2016 due to the adoption of ASU 2016-09, effective January 1, 2016. See Note 2 for further discussion.

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the Chief Executive Officer's restricted shares to vest. Restricted stock is valued at the close of market of the Company’s common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. CEPS awards were first granted in 2014. Both types of awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

For both the TSR awards and the CEPS awards, the Company accounts for them as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2016	2015	2014
Restricted Shares			
Shares granted during the year	58,610	58,302	62,075
Shares vested during the year	(52,385)	(60,379)	(52,899)
Unvested shares at end of year	109,806	106,091	112,042
Unrecognized compensation expense at end of year (in thousands)	$ 1,853	$ 1,705	$ 1,349
TSR Awards			
TSR shares granted during the year	116,435	116,435	117,550
TSR shares vested during the year	(111,665)	(171,334)	(167,584)
TSR shares earned based on market metrics	132,887	222,734	97,199
Unvested TSR shares at end of year	222,228	223,697	287,834
Unrecognized compensation expense (in thousands)	$ 3,409	$ 3,219	$ 2,833
CEPS Awards			
CEPS shares granted during the year	57,521	58,259	59,025
CEPS shares vested during the year	(55,835)	—	—
CEPS shares earned based on market metrics	90,460	—	—
Unvested CEPS shares at end of year	110,452	111,887	58,017
Unrecognized compensation expense (in thousands)	$ 1,671	$ 1,840	$ 1,577

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, the change in the value of the Company’s common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2016 and 2015, the Company had recognized cumulative compensation expense and a liability of $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Other Income - Net

Other Income - net consisted of the following items for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Interest income	$ 1,823	$ 653	$ 987
Interest on regulatory deferrals	1,308	48	220
Equity-related AFUDC	8,475	8,331	8,808
Net gain (loss) on investments	(2,152)	(637)	276
Other income	624	905	1,055
Total	$ 10,078	$ 9,300	$ 11,346

Earnings per Common Share Attributable to Avista Corporation Shareholders

Basic earnings per common share attributable to Avista Corp. shareholders is computed by dividing net income attributable to Avista Corp. shareholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corp. shareholders is calculated by dividing net income attributable to Avista Corp. shareholders (adjusted for the effect of potentially dilutive securities issued to noncontrolling interests by the Company's subsidiaries) by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 18 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2016	2015	2014
Allowance as of the beginning of the year	$ 4,530	$ 4,888	$ 44,309
Additions expensed during the year	6,053	5,802	5,296
Net deductions (1)	(5,557)	(6,160)	(44,717)
Allowance as of the end of the year	$ 5,026	$ 4,530	$ 4,888

(1) During 2014, the Company received $15.0 million in gross proceeds related to the settlement of its California wholesale power markets litigation. The gross proceeds effectively settled all outstanding receivables and payables at Avista Energy (which had been fully reserved against since 2001). As a result of the settlement, the Company reversed $15.0 million of the allowance, which was recorded as a reduction to non-utility other operating expenses on the Consolidated Statements of Income, and the remainder of the receivables, payables and allowance of $24.5 million were removed from the Consolidated Balance Sheets (and had no effect on net income).

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or market for our non-regulated operations and consisted of the following as of December 31 (dollars in thousands):

	2016	2015
Materials and supplies	$ 40,700	$ 37,101
Fuel stock	4,585	4,273
Stored natural gas	8,029	12,774
Total	$ 53,314	$ 54,148

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 9 for further discussion of the Company's asset retirement obligations).

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations. The Company has recorded the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and included them as a regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2016	2015
Regulatory liability for utility plant retirement costs	$ 273,983	$ 261,594

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a qualitative analysis (Step 0) for AEL&P and a combination of discounted cash flow models and a market approach for the other subsidiaries on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2016 and determined that goodwill was not impaired at that time.

The changes in the carrying amount of goodwill are as follows (dollars in thousands):

	AEL&P	Other	Accumulated Impairment	Total
Balance as of January 1, 2015	$ 52,730	$ 12,979	$ (7,733)	$ 57,976
Adjustments	(304)	—	—	(304)
Balance as of the December 31, 2015	52,426	12,979	(7,733)	57,672
Balance as of the December 31, 2016	$ 52,426	$ 12,979	$ (7,733)	$ 57,672

Accumulated impairment losses are attributable to the other businesses. The goodwill adjustments recorded during 2015 relate to the final true-up of income taxes associated with the acquisition of AERC, which occurred on July 1, 2014. See Note 4 for information regarding this business acquisition and Note 21 regarding the Company's reportable segments.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Consolidated Balance Sheets measured at estimated fair value.

The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract that is determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

As of December 31, 2016, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 16 for the Company’s fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. Decoupling revenue deferrals are recognized in the Consolidated Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Consolidated Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in decoupling revenue being recognized in a future period.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

See Note 20 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt and Capital Leases on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

For the Company’s Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company’s other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of December 31 (dollars in thousands):

	2016	2015
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $4,075 and $3,580, respectively	$ 7,568	$ 6,650

The following table details the reclassifications out of accumulated other comprehensive loss by component for the years ended December 31 (dollars in thousands):

	Amounts Reclassified from Accumulated Other Comprehensive Loss			
Details about Accumulated Other Comprehensive Loss Components	2016	2015	2014	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ —	$ (3)	(a)
Realized losses on investment securities	—	—	735	(a)
	—	—	732	Total before tax
	—	—	(272)	Tax expense (a)
	$ —	$ —	$ 460	Net of tax
Amortization of defined benefit pension items				
Amortization of net prior service cost	$ (1,171)	$ 31	$ (1,094)	(b)
Amortization of net loss	(7,602)	2,623	(83,301)	(b)
Adjustment due to effects of regulation	7,360	(749)	78,773	(b)
	(1,413)	1,905	(5,622)	Total before tax
	495	(667)	1,967	Tax benefit (expense)
	$ (918)	$ 1,238	$ (3,655)	Net of tax

(a) These amounts were included as part of net income from discontinued operations for all periods presented (see Note 5 for additional details).

(b) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 10 for additional details).

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company typically calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the AEL&P licenses for Lake Dorothy and Annex Creek/Salmon Creek (combined).

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2016	2015
Appropriated retained earnings	$ 25,564	$ 21,030

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2016.

Capital Leases

The Company has two capital leases, one at Avista Corp. and one at AEL&P. The capital lease at Avista Corp. expires in 2018 and is not material to the financial statements as of December 31, 2016. The capital lease at AEL&P is a PPA (treated as a lease for accounting purposes) related to the Snettisham Hydroelectric Project that expires in 2034. While the two leases are treated as capital leases for accounting purposes, for ratemaking purposes these agreements are treated as operating leases with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates. See Note 14 for further discussion of the Snettisham capital lease.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2016, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 19 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "”Revenue from Contracts with Customers (Topic 606)"

In May 2014, the FASB issued ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU was originally effective for periods beginning after December 15, 2016 and early adoption was not permitted. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 for one year, with adoption as of the original date permitted.

The Company has formed a revenue recognition standard implementation team that is working through several implementation issues described below. The Company has evaluated this standard and is planning to adopt this standard in 2018 upon its effective date. The Company is currently expecting to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company is not far enough along in the adoption process to determine the amount, if any, of cumulative adjustment necessary.

Since the vast majority of Avista Corp.’s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect a significant change in operating revenues or net income. The Company is in the process of reviewing and analyzing certain contracts with customers (most of which are related to wholesale sales of power and natural gas), but has not yet identified any significant differences in revenue recognition between current GAAP and ASU 2014-09.

During the implementation process, the Company has identified several unresolved issues, the most significant of which are as follows based on our current assessment:

Contributions in Aid of Construction – There is the potential that CIACs could be recognized as revenue upon the adoption of ASU 2014-09. Under current GAAP, CIACs are accounted for as an offset to the cost of utility plant in service.

Utility Related Taxes Collected from Customers – There are questions on the presentation of utility related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under current GAAP, the Company is allowed to record these utility related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company is evaluating whether this presentation is appropriate under ASU 2014-09 or whether they should be presented on a net basis. To qualify for gross presentation under the new guidance, the Company must perform an analysis to determine if it is the principal or the agent in regards to utility related taxes.

Collectibility - There are questions regarding the requirement that collection of a sale be probable and how, or if, utilities should consider bad debt collection mechanisms (riders, base rate adjustments, etc.) in assessing probability of collection on sales to low income customers. Within the utility industry, there is support for and against considering these recovery mechanisms when assessing collectibility of a sale. If the bad debt recovery mechanisms cannot be considered, there is the potential that certain sales to low income customers cannot be recognized as revenue until payment is received from the customers, which could result in revenues being recognized in periods other than when the energy was delivered to customers or not recognized at all.

The Company is monitoring utility industry implementation guidance as it relates to unresolved issues to determine if there will be an industry consensus regarding accounting and presentation of these items.

ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis"

In February 2015, the FASB issued ASU No. 2015-02. This ASU changes the consolidation analysis required under GAAP, including the identification of variable interest entities (VIE). The ASU also removes the deferral of the VIE analysis related to investments in certain investment funds, which results in a different consolidation evaluation for these types of investments. The Company adopted this standard effective January 1, 2016. The adoption of this standard resulted in the identification of several Avista Corp. investments in limited partnerships (or a functional equivalent) that are now considered VIEs under the new standard. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the entities, it does not have the power to direct any activities of the entities and it does not have the power to appoint executive leadership (including the board of directors). Avista Corp.'s total investment in these entities is not material and it does not have any additional commitments to these VIEs beyond the initial investment. See Note 3 for additional discussion of VIEs.

ASU No. 2016-02 "Leases (Topic 842)."

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Upon adoption, this ASU must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will most likely not early adopt this standard before its effective date in 2019. The Company has formed a lease standard implementation team that is working through the implementation process. The most significant implementation challenge identified thus far relates to identifying a complete population of leases and potential leases under the new lease standard. Also, the Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus, including whether right-of-ways are considered leases. The Company cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 "”Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting."

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplifies several aspects of the accounting for employee share-based payment transactions including:

- allowing excess tax benefits or tax deficiencies to be recognized as income tax benefits or expenses in the Consolidated Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Consolidated Statements of Cash Flows and instead will be included as an operating activity,
- excess tax benefits and tax deficiencies will be excluded from the calculation of diluted earnings per share, whereas under current accounting guidance, these amounts must be estimated and included in the calculation,
- allowing forfeitures to be accounted for as they occur, instead of estimating forfeitures, and
- changing the statutory tax withholding requirements for share-based payments.

This ASU is effective for periods beginning after December 15, 2016 and early adoption is permitted. The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. In addition, the Consolidated Statement of Cash Flows for 2016 included the excess tax benefits as an operating activity rather than as a financing activity. Periods prior to 2016 were not restated for the adoption of this accounting standard as the Company has adopted this standard on a prospective basis beginning January 1, 2016.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a PPA for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026 and Avista Corp. does not have any further obligations after the expiration. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.’s consolidated financial statements. The Company has a future contractual obligation of approximately $283.6 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Limited Partnerships and Similar Entities

The Company adopted ASU No. 2015-02 effective January 1, 2016. As a result of the adoption of this ASU, the Company evaluated all of its existing investments to determine if any entities would be considered VIEs under the new guidance and whether consolidation would be required. Under the ASU, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership would be considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the “unrelated” limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

The Company has six investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct any activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. For five of the six VIEs, Avista Corp. does not have any additional commitments beyond its initial investment. For the sixth VIE, Avista Corp. has up to a $25.0 million total commitment, and as of December 31, 2016, has invested $2.1 million, leaving $22.9 million remaining to be invested. In addition, the Company is not allowed to withdraw any capital contributions from the investment funds until after the funds' expiration dates and all liabilities of the funds are settled. The expiration dates range from 2017 to 2032, with one investment having no termination date (as it is perpetual). As of December 31, 2016, the Company has a total carrying amount in these investment funds of $7.0 million.

NOTE 4. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company acquired AERC, based in Juneau, Alaska, and as of that date, AERC became a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to approximately 17,000 customers in Juneau, Alaska. In addition to the regulated utility, AERC owns AJT Mining, which is an inactive mining company holding certain properties.

The purpose of the acquisition was to expand and diversify Avista Corp.'s energy assets and deliver long-term value to its customers, communities and investors.

In connection with the closing, Avista Corp. issued 4,501,441 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments. Avista Corp. also paid $4.8 million in cash. The total fair value of all consideration transferred was $154.9 million and resulted in goodwill of $52.4 million, which is not deductible for tax purposes.

The fair value of assets acquired and liabilities assumed as of July 1, 2014 (after consideration of a working capital adjustment and income tax true-ups during the second quarter of 2015) were as follows (in thousands):

	July 1, 2014
Assets acquired:	
Current Assets:	
Cash	$ 19,704
Accounts receivable - gross totals $3,928	3,851
Materials and supplies	2,017
Other current assets	999
Total current assets	26,571
Utility Property:	
Utility plant in service	113,964
Utility property under long-term capital lease	71,007
Construction work in progress	3,440
Total utility property	188,411
Other Non-current Assets:	
Non-utility property	6,660
Electric plant held for future use	3,711
Goodwill (1)	52,426
Other deferred charges and non-current assets	5,368
Total other non-current assets	68,165
Total assets	$ 283,147
Liabilities Assumed:	
Current Liabilities:	
Accounts payable	$ 700
Current portion of long-term debt and capital lease obligations	3,773
Other current liabilities (1)	2,807
Total current liabilities	7,280
Long-term debt	37,227
Capital lease obligations	68,840
Other non-current liabilities and deferred credits (1)	14,889
Total liabilities	$ 128,236
Total net assets acquired	$ 154,911

(1) During the second quarter of 2015, the Company recorded a reduction to goodwill of approximately $0.3 million due to income tax related adjustments.

The majority of AERC's operations are subject to the rate-setting authority of the RCA and are accounted for pursuant to GAAP, including the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for AERC's regulated operations provide revenues derived from costs, including a return on investment, of assets and liabilities included in rate base. Due to this regulation, the fair values of AERC's assets and liabilities subject to these rate-setting provisions were assumed to approximate their carrying values. There were not any identifiable intangible assets associated with this acquisition. The excess of the purchase consideration over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the attractiveness of stable, growing cash flows, as well as providing a platform for potential future growth outside of the rate-regulated electric utility in Alaska and potential additional utility investment.

The following table summarizes the supplemental pro forma information for the years ended December 31 related to the acquisition of AERC as if the acquisition had occurred on January 1, 2013 (dollars in thousands - unaudited):

	2016	2015	2014
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 1,395,989	$ 1,439,807	$ 1,450,918
Supplemental pro forma AERC revenues (1)	46,494	44,969	46,467
Total pro forma revenues	1,442,483	1,484,776	1,497,385
Actual AERC revenues included in Avista Corp. revenues (1)	46,494	44,969	21,644
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	129,505	111,772	116,665
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	—	5,147	72,224
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	—	22	870
Supplemental pro forma AERC net income (1)	7,723	6,308	8,806
Total pro forma net income	137,228	123,249	198,565
Actual AERC net income included in Avista Corp. net income (1)	$ 7,723	$ 6,308	$ 3,152

(1) AERC was acquired on July 1, 2014; therefore, all the revenues and net income for the second half of 2014 through 2016 are actual amounts that are included in Avista Corp.'s overall results. All revenue and net income amounts prior to July 1, 2014 are supplemental pro forma amounts and are excluded from Avista Corp.'s overall results.

(2) This adjustment is to treat all transaction costs as if they occurred on January 1, 2013 and to remove them from the periods in which they actually occurred. The transaction costs were expensed and presented in the Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the transaction through December 31, 2016, Avista Corp. has expensed $3.0 million (pre-tax) in total transaction fees. In addition to the amounts expensed, through December 31, 2016, Avista Corp. has included $0.4 million in fees associated with the issuance of common stock for the transaction as a reduction to common stock. These fees do not impact the supplemental pro forma information above.

NOTE 5. DISCONTINUED OPERATIONS

On June 30, 2014, Avista Capital, completed the sale of its interest in Ecova to Cofely USA Inc., an unrelated party to Avista Corp. The sales price was $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc. and the Company has not had and will not have any further involvement with Ecova after such date.

The purchase price of $335.0 million, as adjusted, was divided among all the security holders of Ecova pro rata based on ownership. After consideration of all escrow amounts received, the sales transaction provided cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.7 million, and resulted in a net gain of $74.8 million. Almost all of the net gain was recognized in 2014 with some true-ups during 2015.

Prior to the completion of the sales transaction, Ecova was a reportable business segment. The following table presents amounts that were included in discontinued operations for the years ended December 31, 2015 and 2014 (dollars in thousands):

	2015	2014
Revenues	$ —	$ 87,534
Gain on sale of Ecova (1)	777	160,612
Transaction expenses and accelerated employee benefits (2)	71	9,062
Gain on sale of Ecova, net of transaction expenses	706	151,550
Income before income taxes	706	156,025
Income tax expense (benefit) (3)	(4,441)	83,614
Net income from discontinued operations	5,147	72,411
Net income attributable to noncontrolling interests	—	(187)
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 5,147	$ 72,224

(1) This represents the gross gain recorded to discontinued operations. The total gain net of taxes and transactions expenses was $74.8 million, of which $69.7 million was recognized during 2014.

(2) Avista Corp.'s portion of the total transaction expenses was $9.1 million (including amounts which were withheld from the transaction net proceeds). All transaction expenses paid on the Ecova sale (including Avista Corp.'s portion and the portion attributable to the minority interest holders of Ecova) were $11.1 million, of which $5.5 million was withheld from the net proceeds and the remainder was paid during 2014. The transaction expenses were for legal, accounting and other consulting fees, and the accelerated employee benefits related to employee stock options which were settled in accordance with the Ecova equity plan.

(3) The tax benefit during 2015 primarily resulted from the reversal of a valuation allowance against net operating losses at Ecova because the net operating losses were deemed realizable after further evaluation.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Utilities is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks.

As part of the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, the Company makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to the Company's distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, the Company plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

The Company is required to plan for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. The Company generally has more pipeline and storage capacity than what is needed during periods other than a peak day. The Company optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Utilities also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that the Company should buy or sell natural gas during other times in the year, the Company engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that are expected to be settled in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2015 that were expected to be settled in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2016	407	1,954	17,252	142,693	280	2,656	3,182	112,233
2017	397	97	675	49,200	255	483	1,360	26,965
2018	397	—	—	15,118	286	—	1,360	2,738
2019	235	—	305	6,935	158	—	1,345	—
2020	—	—	455	905	—	—	1,430	—
Thereafter	—	—	—	—	—	—	1,060	—

(1) Physical transactions represent commodity transactions in which Avista Utilities will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of benefit or cost but with no physical delivery of the commodity, such as futures, swaps, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are settled and will be included in the various recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers. Any transactions that result in gains will be used to reduce retail rates charged to customers in the future.

Foreign Currency Exchange Derivatives

A significant portion of Avista Utilities' natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Utilities' short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within 60 days with U.S. dollars. Avista Utilities hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):

	2016	2015
Number of contracts	21	24
Notional amount (in United States dollars)	$ 2,819	$ 1,463
Notional amount (in Canadian dollars)	3,754	2,002

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Company hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that the Company has outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2016	6	75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022
December 31, 2015	6	115,000	2016
	3	45,000	2017
	11	245,000	2018
	2	30,000	2019
	1	20,000	2022

During the third quarter 2016, in connection with the execution of a purchase agreement for bonds that the Company issued in December 2016, the Company cash-settled seven interest rate swap derivatives (notional aggregate amount of $125.0 million) and paid a total of $54.0 million. The interest rate swap derivatives were settled in connection with the pricing of $175.0 million of Avista Corp. first mortgage bonds that were issued in December 2016 (see Note 14). Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of the Company's cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swaps outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. The Company would be required to make cash payments to settle the interest rate swap derivatives if the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, the Company receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheet as of December 31, 2016 and December 31, 2015 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2016 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments-net and other non-current assets	5,754	(397)	—	5,357
Other current liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2015 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 2	$ (19)	$ —	$ (17)
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	23	—	—	23
Other current liabilities	118	(23,262)	3,880	(19,264)
Non-current interest rate swap derivative liabilities	1,407	(62,236)	30,150	(30,679)
Energy commodity derivatives				
Other current assets	1,236	(553)	—	683
Current energy commodity derivative liabilities	67,466	(85,409)	3,675	(14,268)
Other non-current liabilities, regulatory liabilities and deferred credits	6,613	(39,033)	10,851	(21,569)
Total derivative instruments recorded on the balance sheet	$ 76,865	$ (210,512)	$ 48,556	$ (85,091)

Exposure to Demands for Collateral

The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents the Company's collateral outstanding related to its derivative instruments as of as of December 31 (in thousands):

	2016	2015
Energy commodity derivatives		
Cash collateral posted	$ 17,134	$ 28,716
Letters of credit outstanding	24,400	28,200
Balance sheet offsetting (cash collateral against net derivative positions)	9,858	14,526
Interest rate swap derivatives		
Cash collateral posted	34,900	34,030
Letters of credit outstanding	3,600	9,600
Balance sheet offsetting (cash collateral against net derivative positions)	34,900	34,030

Certain of the Company’s derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If the Company’s credit ratings were to fall below “investment grade,” it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral the Company could be required to post as of December 31 (in thousands):

	2016	2015
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,124	$ 7,090
Additional collateral to post	1,046	6,980
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	73,978	85,498
Additional collateral to post	21,100	18,750

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, Colstrip, located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in thousands):

	2016	2015
Utility plant in service	$ 380,406	$ 362,199
Accumulated depreciation	(249,359)	(243,363)

See Note 9 for further discussion of AROs.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2016	2015
Avista Utilities:		
Electric production	$ 1,346,332	$ 1,217,179
Electric transmission	682,529	640,586
Electric distribution	1,525,175	1,468,157
Electric construction work-in-progress (CWIP) and other	296,912	358,846
Electric total	3,850,948	3,684,768
Natural gas underground storage	44,672	43,080
Natural gas distribution	954,298	878,982
Natural gas CWIP and other	57,601	62,024
Natural gas total	1,056,571	984,086
Common plant (including CWIP)	527,458	456,796
Total Avista Utilities	5,434,977	5,125,650
AEL&P:		
Electric production	94,839	72,292
Electric transmission	20,252	18,817
Electric distribution	20,057	19,005
Electric production held under long-term capital lease	71,007	71,007
Electric CWIP and other	7,190	16,971
Electric total	213,345	198,092
Common plant	8,651	8,133
Total AEL&P	221,996	206,225
Other (1)	30,764	25,709
Total	$ 5,687,737	$ 5,357,584

(1) Included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $11.2 million as of December 31, 2016 and $10.6 million as of December 31, 2015 for the other businesses.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

On April 17, 2015, the EPA published a final rule regarding coal combustion residuals (CCR), also termed coal combustion byproducts or coal ash, in the Federal Register, and this rule became effective on October 15, 2015. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 & 4, produces this byproduct. The rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Company, in conjunction with the other Colstrip owners, developed a multi-year compliance plan to strategically address the CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessments, Avista Corp. recorded an increase to its ARO of $12.5 million during 2015 with a corresponding increase in the cost basis of the utility plant. During 2016, due to additional information and updated estimates, the ARO increased to $13.6 million (including accretion of $0.7 million).

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased ARO due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. Avista Corp. will coordinate with the plant operator and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO for these changes in estimates, which could be material. The Company expects to seek recovery of any increased costs related to complying with the new rule through customer rates.

The following table documents the changes in the Company’s asset retirement obligation during the years ended December 31 (dollars in thousands):

	2016	2015	2014
Asset retirement obligation at beginning of year	$ 15,997	$ 3,028	$ 2,859
Liabilities incurred	430	12,539	—
Liabilities settled	(1,529)	(29)	(41)
Accretion expense	617	459	210
Asset retirement obligation at end of year	$ 15,515	$ 15,997	$ 3,028

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. METALfx (not discussed below) has a defined contribution 401(k) savings plan. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee’s years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company’s funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $12.0 million in cash to the pension plan in 2016, $12.0 million in 2015 and $32.0 million in 2014. The Company expects to contribute $22.0 million in cash to the pension plan in 2017.

The Company also has a SERP that provides additional pension benefits to executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2017	2018	2019	2020	2021	Total 2022-2026
Expected benefit payments	$ 30,971	$ 32,014	$ 33,047	$ 34,545	$ 35,892	$ 196,322

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2017	2018	2019	2020	2021	Total 2022-2026
Expected benefit payments	$ 6,991	$ 7,302	$ 7,580	$ 6,479	$ 6,675	$ 34,704

The Company expects to contribute $7.0 million to other postretirement benefit plans in 2017, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2016 and 2015 and the components of net periodic benefit costs for the years ended December 31, 2016, 2015 and 2014 (dollars in thousands):

	Pension Benefits		Other Post-	
	2016	2015	2016	2015
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 613,503	$ 634,674	$ 138,795	$ 127,989
Service cost	18,302	19,791	3,205	2,925
Interest cost	27,544	26,117	6,110	5,158
Actuarial (gain)/loss	39,997	(35,790)	(3,648)	12,668
Plan change	—	(228)	—	(1,000)
Cumulative adjustment to reclassify liability	—	—	(1,042)	(1,521)
Benefits paid	(32,874)	(31,061)	(6,967)	(7,424)

	Pension Benefits		Other Post-	
	2016	2015	2016	2015
Benefit obligation as of end of year	$ 666,472	$ 613,503	$ 136,453	$ 138,795
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 517,234	$ 539,311	$ 30,868	$ 31,312
Actual return on plan assets	43,212	(4,305)	2,497	(444)
Employer contributions	12,000	12,000	—	—
Benefits paid	(31,532)	(29,772)	—	—
Fair value of plan assets as of end of year	$ 540,914	$ 517,234	$ 33,365	$ 30,868
Funded status	$ (125,558)	$ (96,269)	$ (103,088)	$ (107,927)
Unrecognized net actuarial loss	178,783	162,961	81,979	92,433
Unrecognized prior service cost	23	25	(8,981)	(10,180)
Prepaid (accrued) benefit cost	53,248	66,717	(30,090)	(25,674)
Additional liability	(178,806)	(162,986)	(72,998)	(82,253)
Accrued benefit liability	$ (125,558)	$ (96,269)	$ (103,088)	$ (107,927)
Accumulated pension benefit obligation	$ 583,498	$ 542,209	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 60,670	$ 65,652
For fully eligible employees			$ 34,429	$ 34,498
For other participants			$ 41,354	$ 38,645
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 15	$ 16	$ (5,854)	$ (6,617)
Unrecognized net actuarial loss	116,209	105,925	53,303	60,081
Total	116,224	105,941	47,449	53,464
Less regulatory asset	(108,903)	(99,414)	(47,202)	(53,341)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,321	$ 6,527	$ 247	$ 123

	Pension Benefits		Other Post-	
	2016	2015	2016	2015
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.26%	4.57%	4.23%	4.57%
Discount rate for annual expense	4.57%	4.21%	4.57%	4.16%
Expected long-term return on plan assets	5.40%	5.30%	6.03%	6.36%
Rate of compensation increase	4.78%	4.87%		
Medical cost trend pre-age 65 – initial			7.00%	7.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2023	2022
Medical cost trend post-age 65 – initial			7.00%	7.00%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2024	2023

	Pension Benefits			Other Post-retirement Benefits		
	2016	2015	2014	2016	2015	2014
Components of net periodic benefit cost:						
Service cost	$ 18,302	$ 19,791	$ 15,757	$ 3,205	$ 2,925	$ 1,844
Interest cost	27,544	26,117	26,224	6,110	5,158	5,226
Expected return on plan assets	(27,547)	(28,299)	(32,131)	(1,861)	(1,991)	(1,903)
Amortization of prior service cost	2	2	22	(1,208)	(1,199)	(1,116)
Net loss recognition	8,511	9,451	4,731	5,728	5,095	4,289
Net periodic benefit cost	$ 26,812	$ 27,062	$ 14,603	$ 11,974	$ 9,988	$ 8,340

Plan Assets

The Finance Committee of the Company’s Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers’ performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2016	2015
Equity securities	37%	27%
Debt securities	45%	58%
Real estate	8%	6%
Absolute return	10%	9%

The 2016 target investment allocation percentages were revised in the fourth quarter of 2016 and the pension plan assets were subsequently reinvested during the fourth quarter of 2016 and first quarter of 2017 to move toward the new target investment allocation percentages. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan. Future contributions to the plan will also be increased to improve the funded status of the plan.

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund’s net assets by its units outstanding at the valuation date. The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. The fair values of the closely held investments and partnership interests are based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The fair value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The fair value of pension plan assets was determined as of December 31, 2016 and 2015.

Pension plan other postretirement plan assets whose fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and are included as reconciling items in the tables below.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan’s assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 10,179	$ —	$ 10,179
Fixed income securities:				
U.S. government issues	—	30,919	—	30,919
Corporate issues	—	193,563	—	193,563
International issues	—	34,145	—	34,145
Municipal issues	—	18,888	—	18,888
Mutual funds:				
U.S. equity securities	120,856	—	—	120,856
International equity securities	30,025	—	—	30,025
Absolute return (1)	6,622	—	—	6,622
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	19,779
International equity securities	—	—	—	29,140
Partnership/closely held investments:				
Absolute return (1)	—	—	—	39,077
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	7,649
Total	$ 157,503	$ 287,694	$ —	$ 540,914

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan’s assets measured and reported as of December 31, 2015 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 86	$ 10,641	$ —	$ 10,727
Fixed income securities:				
U.S. government issues	—	47,845	—	47,845
Corporate issues	—	187,308	—	187,308
International issues	—	34,458	—	34,458
Municipal issues	—	22,416	—	22,416
Mutual funds:				
U.S. equity securities	87,678	—	—	87,678
International equity securities	40,343	—	—	40,343
Absolute return (1)	13,996	—	—	13,996
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	24,147
Partnership/closely held investments:				
Absolute return (1)	—	—	—	38,302
Private equity funds (2)	—	—	—	73
Real estate	—	—	—	9,941
Total	$ 142,103	$ 302,668	$ —	$ 517,234

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.

(2) This category includes private equity funds that invest primarily in U.S. companies.

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2016 and 2015.

The fair value of other postretirement plan assets was determined as of December 31, 2016 and 2015.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Mutual funds:				
Balanced index fund (1)	33,359	—	—	33,359
Total	$ 33,359	$ 6	$ —	$ 33,365

(1) The balanced index fund is a single mutual fund that includes a percentage of U.S. equity securities, fixed income securities and International securities.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2015 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 9	$ —	$ 9
Mutual funds:				
Fixed income securities	12,000	—	—	12,000
U.S. equity securities	13,224	—	—	13,224
International equity securities	5,635	—	—	5,635
Total	$ 30,859	$ 9	$ —	$ 30,868

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2016 by $8.6 million and the service and interest cost by $1.0 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2016 by $6.7 million and the service and interest cost by $0.7 million.

401(k) Plans and Executive Deferral Plan

Avista Utilities and METALfx have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Employer 401(k) matching contributions	$ 8,710	$ 8,011	$ 6,862

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets included in other property and investments-net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2016	2015
Deferred compensation assets and liabilities	$ 7,679	$ 8,093

NOTE 11. ACCOUNTING FOR INCOME TAXES

Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Current income tax expense (benefit)	$ (46,457)	$ 12,212	$ (67,059)
Deferred income tax expense	124,543	55,237	139,299
Total income tax expense	$ 78,086	$ 67,449	$ 72,240

State income taxes do not represent a significant portion of total income tax expense on the Consolidated Statements of Income for any periods presented.

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2016, 2015 and 2014) applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2016		2015		2014	
Federal income taxes at statutory rates	$ 75,391	35.0%	$ 64,967	35.0%	$ 67,237	35.0%
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	3,297	1.5	4,358	2.3	4,008	2.1
State income tax expense	1,316	0.6	1,012	0.5	506	0.2
Settlement of prior year tax returns and adjustment of tax reserves	13	—	(992)	(0.5)	1,104	0.6
Manufacturing deduction	—	—	(1,198)	(0.6)	(169)	(0.1)
Settlement of equity awards	(1,597)	(0.7)	—	—	—	—
Other	(334)	(0.1)	(698)	(0.4)	(446)	(0.2)
Total income tax expense	$ 78,086	36.3%	$ 67,449	36.3%	$ 72,240	37.6%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards. The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2016	2015
Deferred income tax assets:		
Unfunded benefit obligation	$ 80,230	$ 75,716
Derivatives	31,872	47,009
Regulatory deferred tax credits	15,192	—
Tax credits	27,931	15,011
Power and natural gas deferrals	19,415	12,866
Deferred compensation	11,141	10,354
Other	29,512	29,471
Total gross deferred income tax assets	215,293	190,427
Valuation allowances for deferred tax assets	(7,946)	(2,862)
Total deferred income tax assets after valuation allowances	207,347	187,565
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	812,916	723,661
Regulatory asset on utility, property plant and equipment	37,301	36,917
Regulatory asset for pensions and other postretirement benefits	84,040	82,253
Utility energy commodity derivatives	31,871	47,010
Long-term debt and borrowing costs	31,955	14,027
Settlement with Coeur d'Alene Tribe	11,711	12,084
Other regulatory assets	30,183	11,691
Other	8,298	7,399
Total deferred income tax liabilities	1,048,275	935,042
Net long-term deferred income tax liability	$ 840,928	$ 747,477

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

As of December 31, 2016, the Company had $17.1 million of state tax credit carryforwards of which it is expected $7.9 million may expire unused; the Company has reflected the net amount of $9.2 million as an asset at December 31, 2016. State tax credits expire from 2019 to 2028.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2011 and all issues were resolved related to these years. The statute of limitations for the IRS to review the 2012 tax year has expired, leaving the 2013 through 2015 tax years still open for review. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the consolidated financial statements.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2016	2015
Regulatory assets for deferred income taxes	$ 109,853	$ 101,240
Regulatory liabilities for deferred income taxes	28,966	17,609

NOTE 12. ENERGY PURCHASE CONTRACTS

The below discussion only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham hydroelectric project and it is accounted for as a capital lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 14 for further discussion of the Snettisham PPA.

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Utility power resources	$ 402,575	$ 511,937	$ 556,915

The following table details Avista Utilities' future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Power resources	$ 202,494	$ 187,080	$ 174,285	$ 109,878	$ 96,485	$ 775,548	$ 1,545,770
Natural gas resources	95,549	65,230	53,860	41,340	29,306	349,468	634,753
Total	$ 298,043	$ 252,310	$ 228,145	$ 151,218	$ 125,791	$ 1,125,016	$ 2,180,523

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. The contractual amounts included above consist of Avista Utilities' share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2016 (principal and interest) was $65.2 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income. The following table details future contractual commitments under these agreements (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Contractual obligations	$ 33,922	$ 28,783	$ 32,549	$ 32,160	$ 27,019	$ 189,000	$ 343,433

NOTE 13. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. A two-year option was exercised by the Company in 2016 to extend the maturity of the facility agreement to April 2021.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2016, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company’s revolving committed lines of credit were as follows as of December 31 (dollars in thousands):

	2016	2015
Balance outstanding at end of period	$ 120,000	$ 105,000
Letters of credit outstanding at end of period	$ 34,353	$ 44,595
Average interest rate at end of period	1.50%	1.18%

As of December 31, 2016 and 2015, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheet.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of December 31, 2016 and 2015, there were no borrowings or letters of credit outstanding under this committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt at AEL&P” to “consolidated total capitalization at AEL&P,” including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2016, AEL&P was in compliance with this covenant.

NOTE 14. LONG-TERM DEBT AND CAPITAL LEASES

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity	Description	Interest	2016	2015
Avista Corp. Secured Long-Term Debt				
2016	First Mortgage Bonds (1)	0.84%	$ —	$ 90,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2051	First Mortgage Bonds (3)	3.54%	175,000	—
	Total Avista Corp. secured long-term debt		1,621,700	1,536,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		1,696,700	1,611,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan	3.85%	15,000	15,000
	Total secured and unsecured long-term debt		1,711,700	1,626,700
Other Long-Term Debt Components				
	Capital lease obligations		65,435	68,601
	Settled interest rate swap derivatives (4)		—	(26,515)
	Unamortized debt discount		(792)	(956)
	Unamortized long-term debt issuance costs		(10,639)	(10,852)
	Total		1,765,704	1,656,978
	Secured Pollution Control Bonds held by Avista Corporation (2)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(3,287)	(93,167)
	Total long-term debt and capital leases		$ 1,678,717	$ 1,480,111

(1) In August 2016, Avista Corp. entered into a term loan agreement with a commercial bank in the amount of $70.0 million with a maturity date of December 30, 2016. Loans under this agreement were unsecured and had a variable annual interest rate. The Company borrowed the entire $70.0 million available under this agreement, which was used to repay a portion of the $90.0 million in first mortgage bonds that matured in August 2016. This term loan was

subsequently repaid in full in December using the proceeds from the first mortgage bonds issued in December 2016 (discussed below).

(2) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.

(3) In December 2016, Avista Corp. issued and sold $175.0 million of 3.54 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. The total net proceeds from the sale of the bonds were used to repay the $70.0 million term loan discussed above and to repay a portion of the borrowings outstanding under the Company’s $400.0 million committed line of credit. In connection with the execution of the bond purchase agreement, the Company cash-settled seven interest rate swap derivatives (notional aggregate amount of $125.0 million) and paid a total of $54.0 million.

(4) Prior to December 31, 2016, settled interest rate swap derivatives were included as part of long-term debt on the Consolidated Balance Sheets because they were considered similar to a debt discount or premium. During 2016, the Company reevaluated the presentation of settled interest rate swap derivatives and determined that since they are regulatory assets and liabilities that are being recovered through the ratemaking process, the more appropriate classification is as regulatory assets and liabilities rather than as a component of long-term debt. As such, as of December 31, 2016, the Company has included unamortized settled interest rate swap derivatives of $91.9 million in regulatory assets and $12.4 million in regulatory liabilities. The Company did not reclassify any amounts as of December 31, 2015 and prior because the amounts are not material to the financial statements. The increase in settled interest rate swap derivatives during 2016 is due to the cash settlement of interest rate swap derivatives discussed in detail above. There is no impact to the Consolidated Statements of Income and the Consolidated Statements of Cash Flows for any periods as a result of the balance sheet reclassification.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 15) (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Debt maturities	$ —	$ 272,500	$ 105,000	$ 52,000	$ —	$ 1,250,047	$ 1,679,547

Substantially all of Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- deposit of cash.

However, Avista Utilities and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has “net earnings” (as defined in that entity's Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2016, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Utilities and $20.8 million at AEL&P.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and AIDEA, an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham Hydroelectric Project. For accounting purposes, this power purchase agreement is treated as a capital lease.

The balances related to the Snettisham capital lease obligation as of December 31 were as follows (dollars in thousands):

	2016	2015
Capital lease obligation (1)	$ 62,160	$ 64,455
Capital lease asset (2)	71,007	71,007
Accumulated amortization of capital lease asset (2)	9,104	5,462

(1) The capital lease obligation amount is equal to the amount of AIDEA's revenue bonds outstanding.

(2) These amounts are included in utility plant in service on the Consolidated Balance Sheets.

Interest on the capital lease obligation and amortization of the capital lease asset are included in utility resource costs in the Consolidated Statements of Income and totaled the following amounts for the years ended December 31 (dollars in thousands):

	2016	2015
Interest on capital lease obligation	$ 3,157	$ 3,587
Amortization of capital lease asset	3,642	3,641

AIDEA issued $100.0 million of revenue bonds in 1998 to finance its acquisition of the project and the payments by AEL&P were designed to be sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds, which bore interest at rates ranging from 4.9 percent to 6.0 percent and were set to mature in January 2034.

In August 2015, AIDEA issued $65.7 million of new revenue bonds for the purpose of refunding all of the remaining outstanding revenue bonds for the Snettisham Hydroelectric Project. The new revenue bonds have interest rates ranging from 4.0 percent to 5.0 percent and mature in January 2034. The capital lease obligation on Avista Corp.'s Consolidated Balance Sheet at any given time is equal to the amount of revenue bonds outstanding at that time. AEL&P is scheduled to make its last capital lease payment to AIDEA in December 2033. The payments by AEL&P under the PPA between AEL&P and AIDEA are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the power purchase agreement. AEL&P is also obligated to operate, maintain and insure the project. The PPA did not change as a result of the refunding, other than lower capital lease payments, and the lower capital lease payments that resulted from the refunding will be passed through to AEL&P's customers. AEL&P's payments for power under the agreement are between $10.0 million and $10.5 million per year, including the capital lease principal and interest of approximately $5.5 million per year.

Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project with certain conditions at any time for the principal amount of the bonds outstanding at that time.

While the power purchase agreement is treated as a capital lease for accounting purposes, for ratemaking purposes this agreement is treated as an operating lease with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates.

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on this evaluation, AIDEA will not be consolidated under ASC 810 "Consolidation" because AIDEA is a government agency and ASC 810 has a specific scope exception which does not allow for the consolidation of government organizations.

The following table details future capital lease obligations, including interest, under the Snettisham PPA (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Principal	$ 2,415	$ 2,535	$ 2,660	$ 2,800	$ 2,935	$ 48,815	$ 62,160
Interest	3,042	2,921	2,795	2,662	2,522	16,674	30,616
Total	$ 5,457	$ 5,456	$ 5,455	$ 5,462	$ 5,457	$ 65,489	$ 92,776

NOTE 15. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the years ended December 31:

	2016	2015	2014
Low distribution rate	1.29%	1.11%	1.10%
High distribution rate	1.81%	1.29%	1.11%
Distribution rate at the end of the year	1.81%	1.29%	1.11%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 16. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Consolidated Balance Sheets as of December 31 (dollars in thousands):

	2016		2015	
	Carrying	Estimated	Carrying	Estimated
Long-term debt (Level 2)	$ 951,000	$ 1,048,661	$ 951,000	$ 1,055,797
Long-term debt (Level 3)	677,000	675,251	592,000	595,018
Snettisham capital lease obligation (Level 3)	62,160	62,800	64,455	63,150
Long-term debt to affiliated trusts (Level 3)	51,547	38,660	51,547	36,083

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 75.00 to 122.59, where a par value of 100.00 represents the carrying value recorded on the Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. Prior to December 31, 2016, the Snettisham capital lease obligation was discounted to present value using the Moody's Aaa Corporate discount rate as published by the Federal Reserve. This rate was discontinued during the fourth quarter of 2016, as such going forward, the Company is using the Morgan Markets A Ex-Fin discount rate, which is the closest approximation to the rate previously used.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2016 and 2015 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Fixed income securities (2)	1,789	—	—	—	1,789
Equity securities (2)	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Foreign currency exchange derivatives	—	28	—	(5)	23
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2015					
Assets:					
Energy commodity derivatives	$ —	$ 74,637	$ —	$ (73,954)	$ 683
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	678	(678)	—
Foreign currency exchange derivatives	—	2	—	(2)	—
Interest rate swap derivatives	—	1,548	—	—	1,548
Deferred compensation assets:					
Fixed income securities (2)	1,727	—	—	—	1,727
Equity securities (2)	5,761	—	—	—	5,761
Total	$ 7,488	$ 76,187	$ 678	$ (74,634)	$ 9,719
Liabilities:					
Energy commodity derivatives	$ —	$ 97,193	$ —	$ (88,480)	$ 8,713
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,717	(678)	5,039
Power exchange agreement	—	—	21,961	—	21,961
Power option agreement	—	—	124	—	124
Foreign currency exchange derivatives	—	19	—	(2)	17
Interest rate swap derivatives	—	85,498	—	—	85,498
Total	$ —	$ 182,710	$ 27,802	$ (89,160)	$ 121,352

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

(2) These assets are trading securities and are included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 6 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.4 million as of December 31, 2016 and $0.6 million as of December 31, 2015.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges), 2) estimated delivery volumes, and 3) volatility rates. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2016 (dollars in thousands):

	Fair Value (Net) at December 31, 2016	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (13,449)	Surrogate facility pricing	O&M charges	$33.59-$49.15/MWh (1)
			Escalation factor	3% - 2017 to 2019
			Transaction volumes	241,558 - 396,984 MWhs
Power option agreement	(76)	Black-Scholes-Merton	Strike price	$37.83/MWh - 2019
				$54.40/MWh - 2018
			Delivery volumes	157,517 - 285,979 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(5,885)	Internally derived weighted-average cost of gas	Forward purchase	$1.83 - $3.06/mmBTU
			Forward sales prices	$1.90 - $5.14/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2016 were $39.22 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2016 were $44.33 for Washington and $39.22 for Idaho.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.35 for 2017 to 0.26 in December 2018.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Year ended December 31, 2016:				
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	259	400	48	707
Settlements	(1,105)	8,112	—	7,007
Ending balance as of December 31, 2016 (2)	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Year ended December 31, 2015:				
Balance as of January 1, 2015	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(6,008)	(6,198)	300	(11,906)
Settlements	1,004	7,536	—	8,540
Ending balance as of December 31, 2015 (2)	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Year ended December 31, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	3,873	(10,002)	351	(5,778)
Settlements	(2,689)	1,144	—	(1,545)
Ending balance as of December 31, 2014 (2)	$ (35)	$ (23,299)	$ (424)	$ (23,758)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 17. COMMON STOCK

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company’s Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

The Company declared the following dividends for the year ended December 31:

	2016	2015	2014
Dividends paid per common share	$ 1.37	$ 1.32	$ 1.27

Under the most restrictive of the dividend limitations discussed above, which are the requirements of the OPUC approval of the AERC acquisition, the amount available for dividends at December 31, 2016 was limited to $263.4 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2016 and 2015.

Stock Repurchase Programs

During 2014 and 2015, Avista Corp.'s Board of Directors approved programs to repurchase shares of the Company's outstanding common stock. The number of shares repurchased and the total cost of repurchases are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests. The average repurchase price was $31.57 in 2014 and $32.66 in 2015. All repurchased shares reverted to the status of authorized but unissued shares.

Equity Issuances

In March 2016, the Company entered into four separate sales agency agreements under which Avista Corp.’s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. In 2016, 1.6 million shares were issued under these agreements resulting in total net proceeds of $65.3 million, leaving 2.2 million shares remaining to be issued.

In 2016, the Company also issued $1.7 million (net of issuance costs) of common stock under the employee plans.

NOTE 18. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2016	2015	2014
Numerator:			
Net income from continuing operations attributable to Avista Corp. shareholders	$ 137,228	$ 118,080	$ 119,817
Net income from discontinued operations attributable to Avista Corp. shareholders	—	5,147	72,224
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	—	—	5
Adjusted net income from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ —	$ 5,147	$ 72,229
Denominator:			
Weighted-average number of common shares outstanding-basic	63,508	62,301	61,632
Effect of dilutive securities:			
Performance and restricted stock awards	412	407	255
Weighted-average number of common shares outstanding-diluted	63,920	62,708	61,887
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 2.16	$ 1.90	$ 1.94
Earnings per common share from discontinued operations	$ —	$ 0.08	$ 1.18
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 2.16	$ 1.98	$ 3.12
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 2.15	$ 1.89	$ 1.93
Earnings per common share from discontinued operations	$ —	$ 0.08	$ 1.17
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 2.15	$ 1.97	$ 3.10

There were no shares excluded from the calculation because they were antidilutive.

NOTE 19. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to Pacific Gas & Electric (PG&E), Southern California Edison, San Diego

Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the “California Parties”). The penalty arises as a result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy’s share of APX’s exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its settlement with the California Parties in 2014 insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX’s assertions of indirect liability, but cannot at this time predict the eventual outcome.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC had failed to take into account new evidence of market manipulation and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the new evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand and on April 5, 2013 expanded the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma and the California AG (on behalf of the California Department of Water Resources). The FERC approved the settlements and they are final.

The remaining direct claimant against Avista Corp. and Avista Energy in this proceeding was the City of Seattle, Washington (Seattle). An evidentiary, trial type hearing before an Administrative Law Judge (ALJ) to permit parties to present evidence of unlawful market activity was conducted in 2013.

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued an Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; 2) Seattle failed to demonstrate that contracts with either Avista Corp. or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that 3) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in any specific violations of substantive provisions of the FPA or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle’s claims under both section 206 and section 309 of the FPA. On May 22, 2015, the FERC issued its Order on Initial Decision in which it upheld the ALJ’s Initial Decision denying all of Seattle’s claims against Avista Corp. and Avista Energy. Seattle filed a Request for Rehearing of the FERC’s Order on Initial Decision which was denied on December 31, 2015. Seattle appealed the FERC’s decision to the Ninth Circuit. In October 2016, Seattle settled all of the matters with the remaining parties and withdrew its appeal at the Ninth Circuit. All the remaining parties signed the settlement agreement and a petition to dismiss the case was filed with the Ninth Circuit on October 27, 2016. There are no remaining claims outstanding under this proceeding. The settlement did not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Litigation

In 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint in the United States District Court for the District of Montana, Billings Division, against the Owners of the Colstrip Generating Project ("Colstrip"); Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-Owners are Talen Montana, LLC (formerly PPL Montana, LLC, an indirect subsidiary of Talen Energy Corporation), Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleged certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs requested that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

The liability trial was scheduled to start on May 31, 2016. The parties engaged in settlement discussions with the Plaintiffs to resolve the claims raised in the litigation. On July 12, 2016, the parties filed a proposed Consent Decree with the court which contained the terms of the settlement of the matter with respect to all four units at Colstrip. The settlement does not include any monetary payments by any party, dismisses all claims against all four units, and provides for the shut-down of units 1 & 2 (which are owned solely by Talen Montana, LLC and Puget Sound Energy) no later than July, 2022. The Consent Decree was entered on September 6, 2016. The parties have petitioned the Court for costs and attorneys' fees. The Court denied the defendant's claim for fees and reduced the plaintiff's claimed fees from approximately $3.0 million to $1.6 million. On February 15, 2017 the Court issued an Order adopting this resolution in full and closing the case.

The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA are working to resolve several issues. The Company believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Utilities' employees. A new three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Utilities' bargaining unit employees was approved in March 2016 and expires in March 2019.

A three-year agreement in Oregon, which covers approximately 50 employees was set to expire in March 2017. A new three-year agreement has been approved by the IBEW membership that will expire in March 2020. It is still awaiting approval from the National IBEW.

A collective bargaining agreement with the local union of the IBEW in Alaska expires in March 2017. The collective bargaining agreement with the IBEW in Alaska represents approximately 50 percent of all AERC employees. The remainder of AERC's employees are non-union.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions of our operations. However, the Company believes that the possibility of this occurring is remote.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company’s policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities’ or AEL&P's operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as “threatened” or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the company holds additional non-hydro water rights. The state of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company’s Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d’Alene basin. The Company is and will continue to be a participant in these and any other relevant adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

NOTE 20. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2016 (dollars in thousands):

	Remaining Amortization	Receiving (1) Earning	Receiving Not Earning	(2) Expected	Total 2016	Total 2015
Regulatory Assets:						
Investment in exchange power-net	2019	$ 6,533	$ —	$ —	$ 6,533	$ 8,983
Regulatory assets for deferred income tax	(3)	101,372	8,481	—	109,853	101,240
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	240,114	—	240,114	235,009
Current regulatory asset for energy commodity derivatives	(5)	—	11,365	—	11,365	17,260
Unamortized debt repurchase costs	(6)	13,700	—	—	13,700	15,520
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	45,265	—	—	45,265	46,576
Demand side management programs	(3)	—	15,700	—	15,700	3,168
Deferred maintenance costs	2018	—	2,672	—	2,672	4,823
Decoupling surcharge	2018	43,126	—	—	43,126	13,312
Regulatory asset for utility plant to be abandoned	(7)	19,100	—	—	19,100	—
Regulatory asset for interest rate swaps	(8)	37,912	—	123,596	161,508	83,973
Non-current regulatory asset for energy commodity derivatives	(5)	—	16,919	—	16,919	32,420
Other regulatory assets	(3)	3,633	5,755	4,585	13,973	17,348
Total regulatory assets		$ 270,641	$ 301,006	$ 128,181	$ 699,828	$ 579,632
Regulatory Liabilities:						
Natural gas deferrals	(3)	$ 30,820	$ —	$ —	$ 30,820	$ 17,880
Power deferrals	(3)	23,528	—	—	23,528	18,747
Regulatory liability for utility plant retirement costs	(9)	273,983	—	—	273,983	261,594
Income tax related liabilities	(3)	—	28,966	—	28,966	17,609
Regulatory liability for interest rate swaps	(8)	12,442	—	8,749	21,191	23
Provision for earnings sharing rebate	(3)	—	3,697	6,600	10,297	12,237
Decoupling rebate	2017	2,405	—	—	2,405	2,373
Other regulatory liabilities	(3)	2,505	3,257	—	5,762	3,420
Total regulatory liabilities		$ 345,683	$ 35,920	$ 15,349	$ 396,952	$ 333,883

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

(6) For the Company's Washington jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are included in the Company's cost of debt calculation for ratemaking purposes and are recovered through retail rates.

(7) In March 2016, the UTC granted the Company's Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of its existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to the Company's plan to replace approximately 253,000 of its existing electric meters with new two-way digital meters and the related software and support services through its AMI project in Washington State. Replacement of the meters is expected to begin in the second half of 2017. For ratemaking purposes, the existing electric meters won't be recorded as regulatory assets until they are physically removed from service, but for GAAP purposes, they are regulatory assets upon the commitment by management to retire the meters.

(8) For interest rate swap derivatives, each period Avista Utilities records all mark-to-market gains and losses in each accounting period as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. This is similar to the treatment of energy commodity derivatives described above. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt and are also included as a part of the Company's cost of debt calculation for ratemaking purposes. See Note 14 regarding a reclassification of settled interest rate swap derivatives during 2016. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery.

(9) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future prudence review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. The Washington ERM calculation is subject to certain deadbands and sharing bands. For 2016, the Company recognized a pre-tax benefit of $5.1 million under the ERM in Washington compared to a benefit of $6.3 million for 2015. Total net deferred power costs under the ERM were a liability of $21.3 million as of December 31, 2016 compared to a liability of $18.0 million as of December 31, 2015, and these deferred power cost balances represent amounts due to customers.

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $2.2 million as of December 31, 2016 compared to an asset of $0.2 million as of December 31, 2015.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. Total net deferred natural gas costs to be refunded to customers were a liability of $30.8 million as of December 31, 2016 compared to a liability of $17.9 million as of December 31, 2015.

Decoupling and Earnings Sharing Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes, rather than KWh and therm sales. The difference between revenues based on the number of customers and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year.

Washington Decoupling and Earnings Sharing

In Washington, the UTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The electric and natural gas decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho Fixed Cost Adjustment (FCA) and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, beginning January 1, 2016.

For the period 2013 through 2015 the Company had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, the Company was required to share with customers 50 percent of any earnings above the 9.8 percent. There was no provision for a surcharge to customers if the Company's ROE was less than 9.8 percent. This after-the-fact earnings test was discontinued as part of the settlement of the Company's 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016 and there will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. An earnings review is conducted on an annual basis, which is filed by the Company with the OPUC on or before June 1 of each year for the prior calendar year. In the annual earnings review, if the Company earns more than 100 basis points above its allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2016 and December 31, 2015, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2016	December 31, 2015
Washington		
Decoupling surcharge	$ 30,408	$ 10,933
Provision for earnings sharing rebate	(5,113)	(3,422)
Idaho		
Decoupling surcharge	$ 8,292	n/a
Provision for earnings sharing rebate	(5,184)	(8,814)
Oregon		
Decoupling surcharge	$ 2,021	n/a
Provision for earnings sharing rebate	—	—

(n/a) This mechanism did not exist during this time period.

NOTE 21. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2016:						
Operating revenues	$ 1,372,638	$ 46,276	$ 1,418,914	$ 23,569	$ —	$ 1,442,483
Resource costs	539,352	12,014	551,366	—	—	551,366
Other operating expenses	304,644	11,151	315,795	25,501	—	341,296
Depreciation and amortization	155,162	5,352	160,514	769	—	161,283
Income (loss) from operations	277,070	15,434	292,504	(2,701)	—	289,803
Interest expense (2)	83,070	3,584	86,654	608	(132)	87,130
Income taxes	74,121	5,321	79,442	(1,356)	—	78,086
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	132,490	7,968	140,458	(3,230)	—	137,228
Capital expenditures (3)	390,690	15,954	406,644	353	—	406,997
For the year ended December 31, 2015:						
Operating revenues	$ 1,411,863	$ 44,778	$ 1,456,641	$ 28,685	$ (550)	$ 1,484,776
Resource costs	644,991	11,973	656,964	—	—	656,964
Other operating expenses	292,096	11,125	303,221	30,076	(550)	332,747
Depreciation and amortization	138,236	5,263	143,499	695	—	144,194
Income (loss) from operations	241,228	14,072	255,300	(2,086)	—	253,214
Interest expense (2)	76,405	3,558	79,963	610	(132)	80,441
Income taxes	64,489	4,202	68,691	(1,242)	—	67,449
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	113,360	6,641	120,001	(1,921)	—	118,080
Capital expenditures (3)	381,174	12,251	393,425	885	—	394,310
For the year ended December 31, 2014:						
Operating revenues	$ 1,413,499	$ 21,644	$ 1,435,143	$ 39,219	$ (1,800)	$ 1,472,562
Resource costs	672,344	5,900	678,244	—	—	678,244
Other operating expenses	280,964	5,868	286,832	32,218	(1,800)	317,250
Depreciation and amortization	126,987	2,583	129,570	610	—	130,180
Income from operations	239,976	6,221	246,197	6,391	—	252,588
Interest expense (2)	73,750	1,382	75,132	1,004	(384)	75,752
Income taxes	67,634	1,816	69,450	2,790	—	72,240
Net income from continuing operations attributable to Avista Corp. shareholders	113,263	3,152	116,415	3,236	166	119,817
Capital expenditures (3)	323,931	1,585	325,516	406	—	325,922
Total Assets:						
As of December 31, 2016	$ 4,975,555	$ 273,770	$ 5,249,325	$ 60,430	$ —	$ 5,309,755
As of December 31, 2015	$ 4,601,708	$ 265,735	$ 4,867,443	$ 39,206	$ —	$ 4,906,649
As of December 31, 2014	$ 4,357,760	$ 263,070	$ 4,620,830	$ 80,141	$ —	$ 4,700,971

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy between Avista Utilities and Spokane Energy (included in other). Intersegment eliminations reported as interest expense and net income (loss) attributable to Avista Corp. shareholders represent intercompany interest.
(2) Including interest expense to affiliated trusts.
(3) The capital expenditures for the other businesses are included as other capital expenditures on the Consolidated Statements of Cash Flows. The remainder of the balance included in other capital expenditures on the Consolidated Statements of Cash Flows for 2014 are related to Ecova.

NOTE 22. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions.

A summary of quarterly operations (in thousands, except per share amounts) for 2016 and 2015 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2016				
Operating revenues	$ 418,173	$ 318,838	$ 303,349	$ 402,123
Operating expenses	312,088	257,247	263,755	319,590
Income from operations	$ 106,085	$ 61,591	$ 39,594	$ 82,533
Net income (1)	57,665	27,287	12,261	40,103
Net income attributable to noncontrolling interests	(16)	(33)	(27)	(12)
Net income attributable to Avista Corporation shareholders (1)	$ 57,649	$ 27,254	$ 12,234	$ 40,091
Outstanding common stock:				
weighted-average, basic	62,605	63,386	63,857	64,185
weighted-average, diluted	62,907	63,783	64,325	64,620
Earnings per common share attributable to Avista Corp. shareholders, diluted (1)	$ 0.92	$ 0.43	$ 0.19	$ 0.62

	Three Months Ended			
	March 31	June 30	September 30	December 31
2015				
Operating revenues from continuing operations	$ 446,490	$ 337,332	$ 313,649	$ 387,305
Operating expenses from continuing operations	356,915	279,972	277,737	316,938
Income from continuing operations	$ 89,575	$ 57,360	$ 35,912	$ 70,367
Net income from continuing operations	$ 46,462	$ 25,078	$ 12,754	$ 33,876
Net income from discontinued operations	—	196	289	4,662
Net income	46,462	25,274	13,043	38,538
Net income attributable to noncontrolling interests	(13)	(28)	(32)	(17)
Net income attributable to Avista Corporation shareholders	$ 46,449	$ 25,246	$ 13,011	$ 38,521
Amounts attributable to Avista Corp. shareholders:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 46,449	$ 25,050	$ 12,722	$ 33,859
Net income from discontinued operations attributable to Avista Corp. shareholders	—	196	289	4,662
Net income attributable to Avista Corp. shareholders	$ 46,449	$ 25,246	$ 13,011	$ 38,521
Outstanding common stock:				
weighted-average, basic	62,318	62,281	62,299	62,308
weighted-average, diluted	62,889	62,600	62,688	62,758
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.74	$ 0.40	$ 0.21	$ 0.54
Earnings per common share from discontinued operations	—	—	—	0.07
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.74	$ 0.40	$ 0.21	$ 0.61

(1) The Company adopted ASU 2016-09 during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. Because this standard was adopted in the second quarter of 2016, but has a retrospective effective date of January 1, 2016, the effects from the adoption were pushed back to the first quarter of 2016 and the results for that quarter were recast in the presentation above. In all future reports which include the first quarter of 2016, the results for that quarter will be recast to include the effects of the excess tax benefits recognized.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three Months Ended March 31

Dollars in thousands, except per share amounts

(Unaudited)

	2017	2016
Operating Revenues:		
Utility revenues	$ 430,537	$ 412,793
Non-utility revenues	5,933	5,380
Total operating revenues	436,470	418,173
Operating Expenses:		
Utility operating expenses:		
Resource costs	165,586	161,719
Other operating expenses	74,484	75,779
Depreciation and amortization	41,985	39,192
Taxes other than income taxes	32,662	29,385
Non-utility operating expenses:		
Other operating expenses	6,179	5,825
Depreciation and amortization	188	188
Total operating expenses	321,084	312,088
Income from operations	115,386	106,085
Interest expense	23,545	21,273
Interest expense to affiliated trusts	185	138
Capitalized interest	(724)	(914)
Other income-net	(3,101)	(2,422)
Income before income taxes	95,481	88,010
Income tax expense	33,344	30,345
Net income	62,137	57,665
Net income attributable to noncontrolling interests	(21)	(16)
Net income attributable to Avista Corp. shareholders	$ 62,116	$ 57,649
Weighted-average common shares outstanding (thousands), basic	64,362	62,605
Weighted-average common shares outstanding (thousands), diluted	64,469	62,907
Earnings per common share attributable to Avista Corp. shareholders:		
Basic	$ 0.97	$ 0.92
Diluted	$ 0.96	$ 0.92
Dividends declared per common share	$ 0.3575	$ 0.3425

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three Months Ended March 31

Dollars in thousands

(Unaudited)

	2017	2016
Net income	$ 62,137	$ 57,665
Other Comprehensive Income (Loss):		
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $98 and $(663) respectively	183	(1,229)
Total other comprehensive income (loss)	183	(1,229)
Comprehensive income	62,320	56,436
Comprehensive income attributable to noncontrolling interests	(21)	(16)
Comprehensive income attributable to Avista Corporation shareholders	$ 62,299	$ 56,420

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands

(Unaudited)

	March 31, 2017	December 31, 2016
Assets:		
Current Assets:		
Cash and cash equivalents	$ 26,179	$ 8,507
Accounts and notes receivable-less allowances of $5,966 and $5,026, respectively	179,403	180,265
Regulatory asset for energy commodity derivatives	11,649	11,365
Materials and supplies, fuel stock and stored natural gas	47,184	53,314
Income taxes receivable	34,159	48,265
Other current assets	58,718	49,625
Total current assets	357,292	351,341
Net Utility Property:		
Utility plant in service	5,543,736	5,506,499
Construction work in progress	158,271	150,474
Total	5,702,007	5,656,973
Less: Accumulated depreciation and amortization	1,533,404	1,509,473
Total net utility property	4,168,603	4,147,500
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Other property and investments-net and other non-current assets	76,525	72,224
Total other non-current assets	145,744	141,443
Deferred Charges:		
Regulatory assets for deferred income tax	117,923	109,853
Regulatory assets for pensions and other postretirement benefits	237,104	240,114
Other regulatory assets	137,366	135,751
Regulatory asset for interest rate swaps	155,027	161,508
Non-current regulatory asset for energy commodity derivatives	15,236	16,919
Other deferred charges	6,064	5,326
Total deferred charges	668,720	669,471
Total assets	$ 5,340,359	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands

(Unaudited)

	March 31, 2017	December 31, 2016
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 72,354	$ 115,545
Current portion of long-term debt and capital leases	3,317	3,287
Short-term borrowings	105,000	120,000
Energy commodity derivative liabilities	7,481	7,035
Accrued interest	28,689	15,869
Accrued taxes other than income taxes	42,853	33,374
Deferred natural gas costs	30,987	30,820
Current portion of pensions and other postretirement benefits	10,906	10,994
Other current liabilities	65,238	70,604
Total current liabilities	366,825	407,528
Long-term debt and capital leases	1,678,113	1,678,717
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	276,533	273,983
Pensions and other postretirement benefits	223,304	226,552
Deferred income taxes	866,861	840,928
Non-current interest rate swap derivative liabilities	23,143	28,705
Other non-current liabilities, regulatory liabilities and deferred credits	168,587	153,319
Total liabilities	3,654,913	3,661,279
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 64,386,152 and 64,187,934 shares issued and outstanding as of March 31, 2017 and December 31, 2016, respectively	1,073,098	1,075,281
Accumulated other comprehensive loss	(7,385)	(7,568)
Retained earnings	619,963	581,014
Total Avista Corporation shareholders' equity	1,685,676	1,648,727
Noncontrolling Interests	(230)	(251)
Total equity	1,685,446	1,648,476
Total liabilities and equity	$ 5,340,359	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Three Months Ended March 31

Dollars in thousands

(Unaudited)

	2017	2016
Operating Activities:		
Net income	$ 62,137	$ 57,665
Non-cash items included in net income:		
Depreciation and amortization	43,084	40,291
Deferred income tax provision and investment tax credits	17,614	34,030
Power and natural gas cost amortizations, net	3,091	5,379
Amortization of debt expense	813	876
Amortization of investment in exchange power	613	613
Stock-based compensation expense	832	2,313
Equity-related Allowance for Funds Used During Construction (AFUDC)	(1,650)	(2,261)
Pension and other postretirement benefit expense	9,348	9,475
Amortization of Spokane Energy contract	—	3,558
Other regulatory assets and liabilities and deferred debits and credits	(6,878)	(7,127)
Change in decoupling regulatory deferral	14,857	(11,456)
Other	(116)	(9)
Contributions to defined benefit pension plan	(7,400)	(4,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	(668)	18,364
Materials and supplies, fuel stock and stored natural gas	6,129	10,263
Collateral posted for derivative instruments	(2,620)	(42,871)
Income taxes receivable	14,106	11,210
Other current assets	(116)	(4,106)
Accounts payable	(20,239)	(30,804)
Other current liabilities	16,778	15,752
Net cash provided by operating activities	149,715	107,155
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(86,763)	(88,878)
Other capital expenditures	(35)	(119)
Issuance of notes receivable at subsidiaries	(400)	(1,076)
Investments made by subsidiaries	(2,627)	(1,358)
Other	(102)	(223)
Net cash used in investing activities	(89,927)	(91,654)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Three Months Ended March 31

Dollars in thousands

(Unaudited)

	2017	2016
Financing Activities:		
Net decrease in borrowings from committed line of credit	$ (15,000)	$ (15,000)
Maturity of long-term debt and capital leases	(822)	(792)
Issuance of common stock, net of issuance costs	315	27,150
Cash dividends paid	(23,167)	(21,545)
Other	(3,442)	(3,031)
Net cash used in financing activities	(42,116)	(13,218)
Net increase in cash and cash equivalents	17,672	2,283
Cash and cash equivalents at beginning of period	8,507	10,484
Cash and cash equivalents at end of period	$ 26,179	$ 12,767

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Three Months Ended March 31

Dollars in thousands

(Unaudited)

	2017	2016
Common Stock, Shares:		
Shares outstanding at beginning of period	64,187,934	62,312,651
Shares issued	198,218	895,408
Shares outstanding at end of period	64,386,152	63,208,059
Common Stock, Amount:		
Balance at beginning of period	$ 1,075,281	$ 1,004,336
Equity compensation expense	922	1,967
Issuance of common stock, net of issuance costs	315	27,150
Payment of minimum tax withholdings for share-based payment awards	(3,420)	(3,027)
Balance at end of period	1,073,098	1,030,426
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(7,568)	(6,650)
Other comprehensive income (loss)	183	(1,229)
Balance at end of period	(7,385)	(7,879)
Retained Earnings:		
Balance at beginning of period	581,014	530,940
Net income attributable to Avista Corporation shareholders	62,116	57,649
Cash dividends paid on common stock	(23,167)	(21,545)
Balance at end of period	619,963	567,044
Total Avista Corporation shareholders’ equity	1,685,676	1,589,591
Noncontrolling Interests:		
Balance at beginning of period	(251)	(339)
Net income attributable to noncontrolling interests	21	16
Balance at end of period	(230)	(323)
Total equity	$ 1,685,446	$ 1,589,268

The Accompanying Notes are an Integral Part of These Statements.

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended March 31, 2017 and March 31, 2016 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. All such adjustments are of a normal recurring nature. The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 (2016 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2016 Form 10-K for definitions of certain terms not defined herein. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

Alaska Energy and Resources Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), which comprises Avista Corp.'s regulated utility operations in Alaska. Avista Capital, Inc. (Avista Capital), a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC.

Basis of Reporting

The condensed consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the three months ended March 31 (dollars in thousands):

	2017	2016
Utility related taxes	$ 21,584	$ 18,365
Property taxes	10,406	10,420
Other taxes	672	600
Total	$ 32,662	$ 29,385

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or net realizable value for our non-regulated operations and consisted of the following as of March 31, 2017 and December 31, 2016 (dollars in thousands):

	March 31, 2017	December 31, 2016
Materials and supplies	$ 42,198	$ 40,700
Fuel stock	4,277	4,585
Stored natural gas	709	8,029
Total	$ 47,184	$ 53,314

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract that is determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

As of March 31, 2017, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Condensed Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 7 for the Company's fair value disclosures.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of March 31, 2017 and December 31, 2016 (dollars in thousands):

	March 31, 2017	December 31, 2016
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $3,977 and $4,075, respectively	$ 7,385	$ 7,568

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three months ended March 31 (dollars in thousands).

	Amounts Reclassified from Accumulated Other Comprehensive Loss		
Details about Accumulated Other Comprehensive Loss Components	2017	2016	Affected Line Item in Statement of Income
Amortization of defined benefit pension items			
Amortization of net prior service cost	$ (299)	$ (311)	(a)
Amortization of net loss	3,638	3,642	(a)
Adjustment due to effects of regulation	(3,058)	(5,223)	(a) (b)
	281	(1,892)	Total before tax
	(98)	663	Tax benefit (expense)
	$ 183	$ (1,229)	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 4 for additional details).

(b) The adjustment for the effects of regulation during the three months ended March 31, 2016 includes approximately $2.1 million related to the reclassification of a pension regulatory asset associated with one of our jurisdictions into accumulated other comprehensive loss.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual if there is a reasonable possibility that a material loss may be incurred. As of March 31, 2017, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 10 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the FASB issued ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU is effective for periods beginning after December 15, 2017.

The Company has formed a revenue recognition standard implementation team that is working through several implementation issues described below. The Company has evaluated this standard and is planning to adopt this standard in 2018 upon its effective date. The Company is currently expecting to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company is not far enough along in the adoption process to determine the amount of cumulative adjustment necessary.

Since the majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect a significant change in operating revenues or net income. The Company is in the process of reviewing and analyzing certain contracts with customers (most of which are related to wholesale sales of power and natural gas), but has not yet identified any significant differences in revenue recognition between current GAAP and ASU No. 2014-09.

During the implementation process, the Company has identified several unresolved issues, the most significant of which are as follows based on our current assessment:

Contributions in Aid of Construction – There is the potential that contributions in aid of construction (CIAC) could be recognized as revenue upon the adoption of ASU No. 2014-09. Under current GAAP, CIACs are accounted for as an offset to the cost of utility plant in service.

Utility-Related Taxes Collected from Customers – There are questions on the presentation of utility related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under current GAAP, the Company is allowed to record these utility related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company is evaluating whether this presentation is appropriate under ASU 2014-09 or whether they should be presented on a net basis.

Collectibility - There are questions regarding the requirement that collection of a sale be probable and how, or if, utilities should consider bad debt collection mechanisms (riders, base rate adjustments, etc.) in assessing probability of collection on sales to low income customers. If the bad debt recovery mechanisms cannot be considered, there is the potential that certain sales to low income customers cannot be recognized as revenue until payment is received from the customers.

The Company is monitoring utility industry implementation guidance as it relates to unresolved issues to determine if there will be an industry consensus regarding accounting and presentation of these items.

In addition to the unresolved issues described above, the Company also expects significant changes to its revenue-related footnote disclosures. The Company continues to evaluate what information would be most useful for users of the financial statements, including information already provided elsewhere in the document outside the footnote disclosures. These additional disclosures could include the disaggregation of revenues by geographic location, type of service, source of revenue or customer class. Also, the Company expects enhanced disclosures regarding its revenue recognition policies and elections.

ASU No. 2016-02 "Leases (Topic 842)."

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Upon adoption, this ASU must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will most likely not early adopt this standard before its effective date in 2019. The Company has formed a lease standard implementation team that is working through the implementation process. The most significant implementation challenge identified thus far relates to identifying a complete population of leases and potential leases under the new lease standard. Also, the Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus, including whether right-of-ways are considered leases. The Company cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting."

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplified several aspects of the accounting for employee share-based payment transactions including:

- allowing excess tax benefits or tax deficiencies to be recognized as income tax benefits or expenses in the Condensed Consolidated Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Condensed Consolidated Statements of Cash Flows and instead will be included as an operating activity,
- requiring excess tax benefits and tax deficiencies to be excluded from the calculation of diluted earnings per share, whereas under previous accounting guidance, these amounts had to be estimated and included in the calculation,
- allowing forfeitures to be accounted for as they occur, instead of estimating forfeitures, and
- changing the statutory tax withholding requirements for share-based payments.

The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. Because this standard was adopted in the second quarter of 2016, but had a retrospective effective date of January 1, 2016, the effects from the adoption were reflected in the first quarter of 2016 and the Condensed Consolidated Financial Statements for that quarter were recast from those presented when the financial statements were originally issued.

ASU No. 2017-07 "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

In March 2017, the FASB issued ASU No. 2017-07, which amends the income statement presentation of the components of net period benefit cost for an entity's defined benefit pension and other postretirement plans. Under current GAAP, net benefit cost consists of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components are aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from current practice, under which entities capitalize the aggregate net benefit cost to utility plant when applicable, in accordance with Federal Energy and Regulatory Commission (FERC) accounting guidance. Avista Corp. is a rate-regulated entity and all components of net benefit cost are currently recovered from rate payers as a component of utility plant and under the new ASU these costs will continue to be recovered from rate payers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of plant for GAAP will be recorded as regulatory assets.

This ASU is effective for periods beginning after December 15, 2017 and early adoption is permitted. Upon adoption, entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement and a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service-cost component. The Company does not expect to early adopt this standard and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

NOTE 3. DERIVATIVES AND RISK MANAGEMENT

The disclosures below in Note 3 apply only to Avista Corp. and its operating division Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of the Avista Corp.'s resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value. Avista Corp. transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of March 31, 2017 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
April - December 2017	214	1,044	8,891	83,808	149	1,101	4,448	61,633
2018	397	246	—	64,415	286	1,244	1,360	33,188
2019	235	737	610	35,623	126	982	1,345	19,598
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,049	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are delivered and will be included in the various recovery mechanisms (ERM, PCA, and Purchased Gas Adjustments (PGA)), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of March 31, 2017 and December 31, 2016 (dollars in thousands):

	March 31, 2017	December 31, 2016
Number of contracts	24	21
Notional amount (in United States dollars)	$ 5,808	$ 2,819
Notional amount (in Canadian dollars)	7,766	3,754

Interest Rate Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that Avista Corp. has outstanding as of March 31, 2017 and December 31, 2016 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
March 31, 2017	6	$ 75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022
December 31, 2016	6	$ 75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates. Upon settlement of interest rate swaps, the cash payments made or received are recorded as a regulatory asset or liability and are amortized as a component of interest expense over the life of the associated debt. The settled interest rate swaps are also included as a part of the Company's cost of debt calculation for ratemaking purposes.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of March 31, 2017 and December 31, 2016 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of March 31, 2017 (in thousands):

	Fair Value as of March 31, 2017			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability)
Foreign currency exchange derivatives				
Other current assets	$ 37	$ —	$ —	$ 37
Interest rate swap derivatives				
Other current assets	3,748	—	—	3,748
Other property and investments-net and other non-current assets	6,754	(116)	—	6,638
Other current liabilities	—	(15,069)	10,100	(4,969)
Non-current interest rate swap derivative liabilities	5,078	(54,261)	26,040	(23,143)
Energy commodity derivatives				
Other current assets	604	(47)	—	557
Current energy commodity derivative liabilities	29,929	(42,136)	4,726	(7,481)
Other non-current liabilities, regulatory liabilities and deferred credits	17,422	(32,658)	2,817	(12,419)
Total derivative instruments recorded on the balance sheet	$ 63,572	$ (144,287)	$ 43,683	$ (37,032)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2016 (in thousands):

	Fair Value as of December 31, 2016			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments-net and other non-current assets	5,754	(397)	—	5,357
Other current liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of March 31, 2017 and December 31, 2016 (in thousands):

	March 31, 2017	December 31, 2016
Energy commodity derivatives		
Cash collateral posted	$ 18,514	$ 17,134
Letters of credit outstanding	30,900	24,400
Balance sheet offsetting (cash collateral against net derivative positions)	7,543	9,858
Interest rate swap derivatives		
Cash collateral posted	36,140	34,900
Letters of credit outstanding	4,800	3,600
Balance sheet offsetting (cash collateral against net derivative positions)	36,140	34,900

Certain of Avista Corp.’s derivative instruments contain provisions that require Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.’s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of March 31, 2017 and December 31, 2016 (in thousands):

	March 31, 2017	December 31, 2016
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 771	$ 1,124
Additional collateral to post	771	1,046
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	69,446	73,978
Additional collateral to post	13,310	21,100

NOTE 4. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

Avista Utilities’ pension and other postretirement plans have not changed during the three months ended March 31, 2017. The Company’s funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $7.4 million in cash to the pension plan for the three months ended March 31, 2017 and expects to contribute a total of $22.0 million in 2017. The Company contributed $12.0 million in cash to the pension plan in 2016.

The Company uses a December 31 measurement date for its defined benefit pension and other postretirement benefit plans. The following table sets forth the components of net periodic benefit costs for the three months ended March 31 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2017	2016	2017	2016
Three months ended March 31:				
Service cost	$ 5,042	$ 4,519	$ 824	$ 779
Interest cost	6,951	6,900	1,399	1,559
Expected return on plan assets	(7,900)	(6,750)	(475)	(475)
Amortization of prior service cost	—	—	(312)	(312)
Net loss recognition	2,546	1,890	1,273	1,365
Net periodic benefit cost	$ 6,639	$ 6,559	$ 2,709	$ 2,916

Total net periodic benefit costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to other operating expenses.

NOTE 5. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021.

Borrowings outstanding and interest rates of borrowings (excluding letters of credit) under the Company’s revolving committed line of credit were as follows as of March 31, 2017 and December 31, 2016 (dollars in thousands):

	March 31, 2017	December 31, 2016
Borrowings outstanding at end of period	$ 105,000	$ 120,000
Letters of credit outstanding at end of period	$ 42,053	$ 34,353
Average interest rates at end of period	1.74%	1.50%

As of March 31, 2017 and December 31, 2016, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of March 31, 2017 and December 31, 2016, there were no borrowings or letters of credit outstanding under this committed line of credit.

NOTE 6. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the three months ended March 31, 2017 and the year ended December 31, 2016:

	March 31, 2017	December 31, 2016
Low distribution rate	1.81%	1.29%
High distribution rate	1.93%	1.81%
Distribution rate at the end of the period	1.93%	1.81%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Condensed Consolidated Balance Sheets. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 7. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable, and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of March 31, 2017 and December 31, 2016 (dollars in thousands):

	March 31, 2017		December 31, 2016	
	Carrying	Estimated	Carrying	Estimated
Long-term debt (Level 2)	$ 951,000	$ 1,077,127	$ 951,000	$ 1,048,661
Long-term debt (Level 3)	677,000	690,772	677,000	675,251
Snettisham capital lease obligation (Level 3)	61,556	62,200	62,160	62,800
Long-term debt to affiliated trusts (Level 3)	51,547	38,145	51,547	38,660

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 74.00 to 129.85, where a par value of 100.0 represents the carrying value recorded on the Condensed Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham capital lease obligation was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on March 31, 2017.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of March 31, 2017 and December 31, 2016 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
March 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 47,856	$ —	$ (47,299)	$ 557
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	99	(99)	—
Foreign currency exchange derivatives	—	37	—	—	37
Interest rate swap derivatives	—	15,580	—	(5,194)	10,386
Deferred compensation assets:					
Fixed income securities (2)	1,725	—	—	—	1,725
Equity securities (2)	5,963	—	—	—	5,963
Total	$ 7,688	$ 63,473	$ 99	$ (52,592)	$ 18,668
Liabilities:					
Energy commodity derivatives	$ —	$ 55,779	$ —	$ (54,842)	$ 937
Level 3 energy commodity derivatives:					

Natural gas exchange agreement	—	—	4,377	(99)	4,278
Power exchange agreement	—	—	14,419	—	14,419
Power option agreement	—	—	266	—	266
Interest rate swap derivatives	—	69,446	—	(41,334)	28,112
Total	$ —	$ 125,225	$ 19,062	$ (96,275)	$ 48,012

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Fixed income securities (2)	1,789	—	—	—	1,789
Equity securities (2)	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Foreign currency exchange derivatives	—	28	—	(5)	23
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

(2) These assets are trading securities and are included in other property and investments-net and other non-current assets on the Condensed Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 3 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.3 million as of March 31, 2017 and $0.4 million as of December 31, 2016.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges), 2) estimated delivery volumes, and 3) volatility rates. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of March 31, 2017 (dollars in thousands):

	Fair Value (Net) at March 31, 2017		Valuation Technique	Unobservable	Range
Power exchange agreement	$	(14,419)	Surrogate facility pricing	O&M charges	$33.59-$49.15/MWh (1)
				Escalation factor	3% - 2017 to 2019
				Transaction volumes	396,984 MWhs
Power option agreement	$	(266)	Black-Scholes-Merton	Strike price	$35.30/MWh - 2019 $50.43/MWh - 2018
				Delivery volumes	125,837 - 285,979 MWhs
				Volatility rates	0.20
Natural gas exchange agreement	$	(4,278)	Internally derived weighted average cost of gas	Forward purchase	$1.65 - $2.83/mmBTU
				Forward sales prices	$1.67 - $3.50/mmBTU
				Purchase volumes	115,000 - 310,000 mmBTUs
				Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2016 are $39.22 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2016 are $44.33 for Washington and $39.22 for Idaho.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three months ended March 31 (dollars in thousands):

		Natural Gas Exchange Agreement		Power Exchange Agreement		Power Option Agreement		Total
Three months ended March 31, 2017:								
Balance as of January 1, 2017	$	(5,885)	$	(13,449)	$	(76)	$	(19,410)
Total gains or (losses) (realized/unrealized):								
Included in regulatory assets/liabilities (1)		2,012		(4,493)		(190)		(2,671)
Settlements		(405)		3,523		—		3,118
Ending balance as of March 31, 2017 (2)	$	(4,278)	$	(14,419)	$	(266)	$	(18,963)
Three months ended March 31, 2016:								
Balance as of January 1, 2016	$	(5,039)	$	(21,961)	$	(124)	$	(27,124)
Total gains or (losses) (realized/unrealized):								
Included in regulatory assets/liabilities (1)		(1,745)		(2,432)		27		(4,150)
Settlements		778		4,200		—		4,978
Ending balance as of March 31, 2016 (2)	$	(6,006)	$	(20,193)	$	(97)	$	(26,296)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 8. COMMON STOCK

In March 2016, the Company entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. As of March 31, 2017, 1.6 million shares have been issued under these agreements, leaving 2.2 million shares remaining to be issued. No shares were issued under these agreements in the three months ended March 31, 2017.

In the three months ended March 31, 2017, Avista Corp. issued 0.2 million shares of common stock, most of which were under employee incentive plans, which have zero proceeds. The Company also issued a small number of shares under the 401K employee investment plan for total net proceeds of $0.3 million.

NOTE 9. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORP. SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the three months ended March 31 (in thousands, except per share amounts):

	2017	2016
Numerator:		
Net income attributable to Avista Corp. shareholders	$ 62,116	$ 57,649
Denominator:		
Weighted-average number of common shares outstanding-basic	64,362	62,605
Effect of dilutive securities:		
Performance and restricted stock awards	107	302
Weighted-average number of common shares outstanding-diluted	64,469	62,907
Earnings per common share attributable to Avista Corp. shareholders:		
Basic	$ 0.97	$ 0.92
Diluted	$ 0.96	$ 0.92

There were no shares excluded from the calculation because they were antidilutive.

NOTE 10. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to the California Parties (as defined in the 2016 Form 10-K). The penalty arises as a result of the Federal Energy and Regulatory Commission's (FERC) finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in

FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy’s share of APX’s exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its 2014 settlement with the California Parties insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX’s assertions of indirect liability, but cannot at this time predict the eventual outcome.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.’s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA are working to resolve several issues. The Company believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant. See "Note 19 of the Notes to Consolidated Financial Statements" in the 2016 Form 10-K for additional discussion regarding other contingencies

NOTE 11. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

The following table presents information for each of the Company’s business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations	Total
For the three months ended March 31, 2017:						
Operating revenues	$ 415,381	$ 15,156	$ 430,537	$ 5,933	$ —	$ 436,470
Resource costs	162,613	2,973	165,586	—	—	165,586
Other operating expenses	71,712	2,772	74,484	6,179	—	80,663
Depreciation and amortization	40,538	1,447	41,985	188	—	42,173
Income (loss) from operations	108,635	7,185	115,820	(434)	—	115,386
Interest expense (2)	22,683	894	23,577	167	(14)	23,730
Income taxes	31,017	2,463	33,480	(136)	—	33,344
Net income (loss) attributable to Avista Corp. shareholders	58,439	3,853	62,292	(176)	—	62,116
Capital expenditures (3)	85,403	1,360	86,763	35	—	86,798
For the three months ended March 31, 2016:						
Operating revenues	$ 400,147	$ 12,646	$ 412,793	$ 5,380	$ —	$ 418,173
Resource costs	159,078	2,641	161,719	—	—	161,719
Other operating expenses	73,256	2,523	75,779	5,825	—	81,604
Depreciation and amortization	37,866	1,326	39,192	188	—	39,380
Income (loss) from operations	101,245	5,473	106,718	(633)	—	106,085
Interest expense (2)	20,418	895	21,313	161	(63)	21,411
Income taxes	28,672	1,895	30,567	(222)	—	30,345
Net income (loss) attributable to Avista Corp. shareholders	54,987	2,961	57,948	(299)	—	57,649
Capital expenditures (3)	84,435	4,443	88,878	119	—	88,997
Total Assets:						
As of March 31, 2017:	$ 5,003,014	$ 276,495	$ 5,279,509	$ 60,850	$ —	$ 5,340,359
As of December 31, 2016:	$ 4,975,555	$ 273,770	$ 5,249,325	$ 60,430	$ —	$ 5,309,755

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy. Intersegment eliminations reported as interest expense and net income (loss) attributable to Avista Corp. shareholders represent intercompany interest.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included as other capital expenditures on the Condensed Consolidated Statements of Cash Flows.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS OF HYDRO ONE LIMITED

Hydro One Limited ("Hydro One" or the "Corporation"), Olympus Holding Corp., Olympus Corp. and Avista Corporation ("Avista") entered into an agreement and plan of merger dated as of July 19, 2017 (the "Merger Agreement"). Pursuant to the Merger Agreement, Hydro One will directly or indirectly acquire Avista (the "Merger") for US$53 (approximately C$67 using the exchange rate of C$1.264 = US$1.00 on July 18, 2017) per Avista common share for an aggregate purchase price of approximately US$5,315 million (approximately C$6,720 million using the exchange rate of C$1.264 = US$1.00 on July 18, 2017), comprised of an equity purchase of approximately US$3,446 million (approximately C$4,357 million using the exchange rate of C$1.264 = US$1.00 on July 18, 2017) and the assumption of approximately US$1,869 million of Avista's outstanding debt (approximately C$2,363 million using the exchange rate of C$1.264 = US$1.00 on July 18, 2017).

The accompanying unaudited *pro forma* condensed consolidated financial statements give effect to the proposed acquisition by Hydro One of Avista under the acquisition method of accounting. The unaudited *pro forma* condensed consolidated balance sheet gives effect to the Merger as if it had closed on March 31, 2017. The unaudited *pro forma* consolidated statements of operations for the year ended December 31, 2016 and the three months ended March 31, 2017 give effect to the Merger as if had closed on January 1, 2016.

The following unaudited *pro forma* condensed consolidated financial statements are based on Avista's historical unaudited consolidated financial statements as at and for the three months ended March 31, 2017 and audited consolidated financial statements for the year ended December 31, 2016 and Hydro One's historical unaudited consolidated financial statements as at and for the three months ended March 31, 2017 and audited consolidated financial statements for the year ended December 31, 2016 and present the effects of the Merger on the combined historical financial statements of Hydro One and Avista. The unaudited *pro forma* condensed consolidated financial statements should be read together with the notes to the unaudited *pro forma* condensed consolidated financial statements and the historical financial statements of Hydro One and Avista.

The unaudited *pro forma* condensed consolidated financial statements (referred to herein as the *pro forma* financial information) are presented for illustrative purposes only and do not include, among other things, estimated cost synergies, adjustments related to restructuring or integration activities and further acquisitions or disposals not yet known or probable. The *pro forma* adjustments are based upon available information and certain assumptions that Hydro One believes are reasonable in the circumstances, as described in the notes to the unaudited pro forma condensed consolidated financial statements.

At the date of preparation of this *pro forma* financial information, certain *pro forma* adjustments have been made as identified herein; however, the fair values of Avista's identifiable assets and liabilities to be assumed and the full impact of applying acquisition accounting have not been fully determined. After reflecting the *pro forma* adjustments made herein, the excess of the purchase consideration over the adjusted book values of Avista's net assets has been presented as goodwill. It is expected that following closing of the Merger and once detailed valuations are completed, a portion of the amount allocated to goodwill may be attributable to property, plant and equipment, intangible assets, other assets and liabilities and related deferred income tax balances. Some property, plant and equipment and intangible assets are expected to be finite-lived and accordingly eventual fair values adjustments will be subject to amortization. As such, the actual amount assigned to the fair values of the identifiable assets and liabilities acquired will result in changes to earnings in periods subsequent to the Merger, and those changes could be material.

The *pro forma* financial information is presented for informational purposes only and is not necessarily indicative of what Hydro One's actual financial condition or results of operations would have been had the Merger been completed on the date indicated, nor does it purport to project Hydro One's future financial position or results of operations for any future periods or as of any future date. Accordingly, the combined business, assets, results of operations and financial condition may differ significantly from those indicated.

Please note that the *pro forma* financial information uses foreign exchange rates in effect at March 31, 2017 and the average foreign exchange rate for the 12 and 3 month periods ending December 31, 2016 and March 31, 2017 (see Note 5). Certain number quoted elsewhere and in the Prospectus may not use these same exchange rates which may result in different numbers quoted.

Hydro One Limited
Consolidated Pro Forma Balance Sheet
As at March 31, 2017
(millions of Canadian dollars)

	Hydro One Limited	Avista [(1)]Corporation	Adjustments	Note	Hydro One Limited Pro Forma Consolidated
Assets					
Current assets:					
Cash and cash equivalents	23	35	1,295	**3B**	-
			3,325	**3C**	
			(4,583)	**3A**	
			(164)	**3D**	
			69	**3H**	
Accounts receivable	740	239			979
Due from related parties	203	-			203
Regulatory asset for energy commodity derivatives	-	15			15
Materials and supplies, fuel stock and stored natural gas	-	63			63
Income taxes receivable	-	45			45
Other current assets	99	78			177
	1,065	475	(58)		1,482
Property, plant and equipment	19,324	5,544			24,868
Other long-term assets:					
Regulatory assets	3,154	881	126	**3I**	4,161
Deferred income tax assets	1,180	-	3	**3G**	1,211
			28	**3B**	
Intangible assets	347	-			347
Goodwill	327	77	(77)	**3A**	2,746
			2,462	**3A**	
Other assets	8	126			134
	24,340	6,628	2,542		33,467
Total assets	**25,405**	**7,103**	**2,484**		**34,949**

(1) Avista Corporation's financial statements have been translated to Canadian dollars as described in Note 5 of these *pro forma* financial statements.

Hydro One Limited
Consolidated Pro Forma Balance Sheet
As at March 31, 2017
(millions of Canadian dollars)

	Hydro One Limited	Avista [1]Corporation	Adjustments	Note	Hydro One Limited Pro Forma Consolidated
Liabilities					
Current liabilities:					
Short-term notes payable	451	140	69	**3H**	660
Long-term debt payable within one year	602	4			606
Accounts payable and other current liabilities	984	183	(8)	**3G**	1,159
Due to related parties	111	-			111
Energy commodity derivative liabilities	-	10			10
Accrued interest	-	38			38
Accrued taxes other than income taxes	-	57			57
Deferred natural gas costs	-	41			41
Current portion of pensions and other postretirement benefits	-	15			15
	2,148	488	61		2,697
Long term liabilities:					
Long-term debt	10,080	2,301	126 3,325	**3I** **3C**	15,832
Regulatory liabilities	211	534			745
Deferred income tax liabilities	61	1,153			1,214
Pension and other postretirement benefits	-	297			297
Non-current interest rate swap derivative liabilities	-	31			31
Other long-term liabilities	2,766	58			2,824
	13,118	4,374	3,451		20,943
Total liabilities	**15,266**	**4,862**	**3,512**		**23,640**
Noncontrolling interest subject to redemption	22	-			22

(1) Avista Corporation's financial statements have been translated to Canadian dollars as described in Note 5 of these *pro forma* financial statements.

Hydro One Limited
Consolidated Pro Forma Balance Sheet
As at March 31, 2017
(millions of Canadian dollars)

	Hydro One Limited	Avista (1)Corporation	Adjustments	Note	Hydro One Limited Pro Forma Consolidated
Equity					
Common shares	5,623	1,427	1,364	**3B**	6,987
			(1,427)	**3A, F**	
Preferred shares	418	-			418
Additional paid-in capital	40	-	-		40
Retained earnings	3,992	824	(164)	**3D**	3,798
			(41)	**3B**	
			(824)	**3A, F**	
			11	**3G**	
Accumulated other comprehensive loss	(7)	(10)	10	**3A, F**	(7)
Shareholders' equity	10,066	2,241	(1,028)		11,236
Noncontrolling interest	51	-			51
Total equity	**10,139**	**2,241**	**(1,028)**		**11,309**
Total liabilities and equity	**25,405**	**7,103**	**2,484**		**34,949**

(1) Avista Corporation's financial statements have been translated to Canadian dollars as described in Note 5 of these *pro forma* financial statements.

Hydro One Limited
Consolidated Pro Forma Statement of Operations
For the three months ended March 31, 2017
(millions of Canadian dollars)

	Hydro One Limited	Avista [1] Corporation	Adjustments	Note	Hydro One Limited Pro Forma Consolidated
Revenues					
Distribution	1,279	-			1,279
Transmission	367	-			367
Utility revenues	-	570			570
Other	12	8			20
	1,658	**578**	**-**		**2,236**
Costs					
Purchased power [2]	889	219			1,108
Operation, maintenance and administration	271	150			421
Depreciation and amortization	195	56			251
Other income-net	-	(4)			(4)
	1,355	**421**	**-**		**1,776**
Income before financing charges and income taxes	**303**	**157**	**-**		**460**
Financing charges	103	30	34	**3F**	167
Income before income taxes	**200**	**127**	**(34)**		**293**
Income taxes	27	44	(11)	**3G**	60
Net income	**173**	**83**	**(23)**		**233**
Basic earnings per share	$0.28				$0.34
Diluted earnings per share	$0.28				$0.34

(1) Avista Corporation's financial statements have been translated to Canadian dollars as described in Note 5 of these *pro forma* financial statements.

(2) Purchased power include the cost of purchased natural gas.

Hydro One Limited
Consolidated Pro Forma Statement of Operations
For the year ended December 31, 2016
(millions of Canadian dollars)

	Hydro One Limited	**Avista [1]Corporation**	**Adjustments**	**Note**	**Hydro One Limited Pro Forma Consolidated**
Revenues					
Distribution	4,915	-			4,915
Transmission	1,584	-			1,584
Utility revenues	-	1,879			1,879
Other	53	31			84
	6,552	**1,910**	**-**		**8,462**
Costs					
Purchased power [2]	3,427	730			4,157
Operation, maintenance and administration	1,069	583			1,652
Depreciation and amortization	778	214			992
Other income-net	-	(13)			(13)
	5,274	**1,514**	**-**		**6,788**
Income before financing charges and income taxes	**1,278**	**396**	**-**		**1,674**
Financing charges	393	112	134	**3F**	639
Income before income taxes	**885**	**284**	**(134)**		**1,035**
Income taxes	139	103	(43)	**3G**	199
Net income	**746**	**181**	**(91)**		**836**
Basic earnings per share	$1.21				$1.23
Diluted earnings per share	$1.21				$1.23

(1) Avista Corporation's financial statements have been translated to Canadian dollars as described in Note 5 of these *pro forma* financial statements.

(2) Purchased power include the cost of purchased natural gas.

1. DESCRIPTION OF THE ACQUISITION

Hydro One Limited ("Hydro One" or the "Corporation"), Olympus Holding Corp., Olympus Corp. and Avista Corporation ("Avista") entered into an agreement and plan of merger dated as of July 19, 2017 (the "Merger Agreement"). Pursuant to the Merger Agreement, Hydro One will directly or indirectly acquire Avista (the "Merger") for US$53 (approximately C$67 at the exchange rate of C$1.264 = US$1.00 on July 18, 2017) per Avista common share for an aggregate purchase price of approximately US$5,315 million (approximately C$6,720 million at the exchange rate C$1.264 = US$1.00 on July 18, 2017), comprised of an equity purchase of approximately US$3,446 million (approximately C$4,357 million at the exchange rate of C$1.264 = US$1.00 on July 18, 2017) and the assumption of approximately US$1,869 million of Avista's outstanding debt (approximately C$2,363 million at the exchange rate of C$1.264 = US$1.00 on July 18, 2017). Since the purchase price is denominated in US dollars, the actual Canadian dollar purchase price paid on closing will be based on exchange rates on that date.

The accompanying *pro forma* financial information assumes that at closing, the Merger will be financed through the net proceeds from issuance of $C1,400 million of 4% convertible unsecured subordinated debentures (the "Debentures") which are assumed to be converted to shares on closing of the Merger at C$21.40 per share. The balance of the purchase price is expected to be funded through medium and long-term debt (as defined and described below). These *pro-forma* condensed consolidated financial statements assume that the over-allotment option granted in connection with the common equity issuance will not be exercised

Hydro One proposes to issue US dollar denominated medium and long term debt in the amount of US$2,650 million (approximately C$3,350 million at the exchange rate on July 18, 2017) maturing over 5, 10 and 30 years respectively.

The accompanying *pro forma* financial information assumes that the Debentures will be issued and immediately fully converted into Hydro One common shares at the assumed closing date of the Merger. Therefore, the accompanying *pro forma* financial information does not recognize interest costs associated with the Debentures. Hydro One anticipates that the closing will occur in the second half of 2018. As a result the Corporation has included the cost of interest on the Debentures for an estimated 12 month period from issuance to their conversion on an assumed Merger closing date in August 2018 as a *pro-forma* adjustment. Due to many factors, including the timing of regulatory approvals, the estimated Merger closing period is subject to change which may change the amount of interest expense incurred on the Debentures and the related income tax recovery. Interest costs associated with the Debentures are expected to be funded through operating cash flows.

2. BASIS OF PRESENTATION

The accompanying *pro forma* financial information gives effect to the proposed Merger by Hydro One of Avista as described in the short form prospectus dated August 1, 2017 (the "Prospectus"). The accompanying *pro forma* financial information has been prepared by management of Hydro One and are derived from the unaudited and audited consolidated financial statements of Hydro One as at and for the three months ended March 31, 2017 and for the year ended December 31, 2016, respectively, and the unaudited and audited consolidated financial statements of Avista as at and for the three months ended March 31, 2017 and for the year ended December 31, 2016, respectively.

The *pro forma* financial information utilizes accounting policies that are consistent with those disclosed in Hydro One's and Avista's audited consolidated financial statements as at and for the year ended December 31, 2016 and unaudited consolidated financial statements as at and for the three months ended March 31, 2017 and were prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

The unaudited *pro forma* consolidated balance sheet is prepared to reflect the Merger assuming it had closed on March 31, 2017. The unaudited *pro forma* consolidated statements of operations for the three months ended March 31, 2017 and for the year ended December 31, 2017 are prepared to reflect the Merger as if it had closed on January 1, 2016. The unaudited pro forma consolidated financial statements may not be indicative of the results that would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the purchase price paid will be based on the exchange rates on the date of closing of the Merger, and the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon Hydro One's evaluation of such assets and liabilities following the closing of the Merger. Accordingly, the final purchase price allocation may differ materially from the preliminary allocation reflected herein.

The accompanying *pro forma* financial information should be read in conjunction with the description of the Merger and the financing thereof provided in the Prospectus; the audited and unaudited consolidated financial statements of Avista, including the notes thereto, included in the Prospectus; and the audited and unaudited consolidated financial statements of Hydro One, including the notes thereto, incorporated by reference in the Prospectus.

Certain amounts in the historical financial statements of Avista have been reclassified in the unaudited *pro forma* balance sheet and statements of operations to reflect the presentation classifications in Hydro One's consolidated financial statements. In addition the historical financial statements of Avista have been converted from U.S. dollars to Canadian dollars to conform to the reporting and reporting currency of Hydro One.

Management believes the underlying assumptions for the *pro forma* adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Merger. These *pro forma* adjustments are tentative and are based on currently available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, it is expected that the actual adjustments will differ from the *pro forma* adjustments shown in the *pro forma* financial information, and the differences may be material.

The *pro forma* financial information presents the combined effect on the historical statements and provides the following resulting information:

Historical Information of Hydro One and Avista	**Historical Dates and Giving Effect**	**Resulting Information**
Unaudited consolidated balance sheet	As of March 31, 2017	Unaudited *pro forma* condensed consolidated balance sheet, referred to as the unaudited *pro forma* balance sheet
Audited consolidated statement of operations for the year ended December 31, 2016 and unaudited consolidated statement of operations for the three months ended March 31, 2017	For the year ended December 31, 2016; and for the three months ended March 31, 2017	Unaudited *pro forma* condensed consolidated statement of operations, referred to as the unaudited *pro forma* statements of operations. Limited fair value adjustments to net assets acquired at March 31, 2017 have been applied to the assumed merger date of January 1, 2016 for purposes of the unaudited *pro forma* statements of operations (see note 3).

Amounts in the notes to the unaudited *pro forma* consolidated financial statements are stated in Canadian dollars, unless otherwise indicated. Please note that the *pro forma* financial information uses foreign exchange rates in effect at March 31, 2017 and the average foreign exchange rate for the 12 and 3 month periods ending December 31, 2016 and March 31, 2017. Certain numbers quoted elsewhere and in the Prospectus may not use these same exchange rates which may result in different numbers quoted. The accompanying *pro forma* financial information may not be indicative of the results that would have been achieved if the transactions reflected herein had been completed on the dates indicated or the results which may be obtained in the future.

3. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

A. *Pro forma* Purchase Price and Purchase Price Allocation

At the date of preparation of this *pro forma* financial information, certain *pro forma* adjustments have been made as identified herein; however, the purchase price paid fair values of Avista's identifiable assets and liabilities to be assumed and the full impact of applying acquisition accounting have not been fully determined. After reflecting the *pro forma* adjustments made herein, the excess of the purchase price consideration over the adjusted book values of Avista's net assets has been presented as goodwill offset by an adjustment to eliminate Avista's historical goodwill.

The Merger consideration in the unaudited *pro forma* financial information is based on the agreed price of US$53 per share. For purpose of the *pro forma* balance sheet at March 31, 2017, the purchase price has been measured at the exchange rate of C$1.33=US$1.00. The pro forma statements of operations are prepared based on the assumption the Merger occurred on January 1, 2016, on which date the exchange rate was approximately C$1.34=US$1.00.

Avista is a public utility subject to regulation by state utility commissions. The retail electric and natural gas operations are subject to the jurisdiction of various regulatory bodies, including FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales. The revenues and earnings approved by the utility commissions are based on regulated rates of return that are applied to historic values of the regulated assets. Therefore, no fair value adjustments are expected to be made to property, plant and equipment and intangible assets with respect to the regulated entities of Avista because all economic benefits and obligations associated with regulated assets beyond regulated thresholds accrue to Avista's customers.

The following is the estimated net purchase price, estimated net funding requirements and assumed financing structure for the Merger. These estimates have been reflected in the accompanying unaudited *pro forma* financial information.

		Using exchange rates in effect on July 18, 2017 (*in millions of Canadian dollars*)	Using exchange rates in effect on March 31, 2017 (*in millions of Canadian dollars*)
Estimated Net Purchase Price			
Estimated net purchase price, before assumed debt*	$	4,357	4,583
Assumed debt of Avista		2,363	2,486
Estimated purchase price	$	6,720	7,069
Estimated Net Funding Requirements			
Estimated net purchase price before assumed long-term debt	$	4,357	4,583
Assumed debt of Avista		2,363	2,486
Common share issuance costs (Note 3(B))		49	49
Long term debt issuance costs (Note 3(C))		25	25
Estimated transaction costs (Note 3(D),(E))		161	164

Interest on debentures, net of tax (Note 3(B))		41	41
Estimated net funding requirements	$	6,996	7,348
Assumed Financing Structure			
Assumed debt of Avista	$	2,363	2,486
Gross proceeds from Debenture issuance, subsequently converted to common shares (Note 3(B))		1,400	1,400
Issuance of long term debt (Note 3(C))		3,350	3,350
Shortfall (excess) from term financing		(117)	112
	$	6,996	7,348

*This purchase price is based on Avista's outstanding shares valued at a foreign exchange rate of C$1.264 on July 18, 2017. The purchase price used for the purposes of caluclating *proforma* adjustments is based an exchange rate at March 31, 2017 described in section 5 below.

B. Assumed financing for the Merger contemplates the issuance, through the exercise of conversion rights under the Debentures, of approximately 65 million common shares at C$21.40 per share for gross proceeds of approximately C$1,400 million. The Debentures include an over-allotment option to purchase additional Debentures represented by Instalment Receipts equal to up to 10% of the aggregate principal amount of Debentures represented by Instalment Receipts sold on the Closing Date which if exercised would result in the issuance of an additional 7 million common shares for gross proceeds of C$140 million. The pro forma condensed consolidated financial statements assume that the over-allotment will not be exercised.

Underwriting costs are estimated at 3.5% of gross proceeds in the aggregate of approximately C$49 million (or C$54 million if the over-allotment option is exercised in full) and will result in a corresponding deferred tax asset of approximately C$13 million based on Hydro One's Canadian statutory income tax rate of 26.5%.

Interests costs associated with the Debentures at 4.0% are expected to be approximately C$56 million (or approximately C$62 million if the over-allotment option is exercised in full) for a 12 month period following issuance of the Debentures and prior to closing and will result in a corresponding deferred income tax asset of approximately C$15 million based on Hydro One's Canadian statutory income tax rate of 26.5%. These unaudited *pro forma* financial statements assume the Debentures will be issued and fully converted into Hydro One common shares at the assumed closing date of the Merger. As this incremental interest is directly related to the acquisition and is non-recurring, the accompanying unaudited *pro forma* consolidated statements of operations do not include interest costs associated with the Debentures. However, estimated interest costs for the 12 month period and the related tax effect have been reflected as a pro forma adjustment to retained earnings in the unaudited *pro forma* consolidated balance sheet. The Debentures provide for a make-whole interest payment to Debenture Holders if the Merger closes earlier than 12 months from the date of the Debenture issuance as more fully described in the Prospectus. No make-whole payments have been reflected in these *pro forma* financial statements on the basis that the *pro forma* adjustments assume that the Merger closes 12 months from the date of the Debenture issuance.

C. Issuance of US denominated medium and long term debt. Hydro One proposes to issue US denominated medium and long term debt that would be equivalent to approximately C$3,350 million over terms ranging from 5, 10 and 30 years bearing interest at a weighted average rate of 4%. Debt issuance costs are estimated at C$25 million. The terms of the debt outlined above are current estimates only. The terms of the actual debt issued will not be known until the time of issuance and could vary significantly from what is proposed based on many factors including market conditions.

D. Transactions costs are estimated at approximately C$114 million and are composed of estimated investment banking, advisory, accounting and legal fees and real estate transfer taxes. Change in control payments are estimated at approximately C$50 million and represent estimated change in control liabilities payable as a result of the Merger. Transaction costs and change in control payments of C$164 million were assumed to be paid in cash based on estimates by Hydro One management. These costs have been included as a *pro forma* adjustment to retained earnings on the unaudited *pro forma* balance sheet as opposed to being reflected in the unaudited *pro forma* statement of earnings on the basis that these expenses are directly attributable to the Merger of Avista and are non-recurring in nature.

E. Elimination of Avista's historical outstanding common shares C$1,427 million, retained earnings C$824 million and accumulated other comprehensive loss C$10 million as of March 31, 2017.

F. Interest expense on the Company's medium and long-term Notes described in Note 3(C) of C$34 million and C$134 million for the 3 months ended March 31, 2017 and the year ended December 31, 2016, respectively.

G. Adjustment to deferred income tax assets relates to the tax saving earned from the deduction of interest expense incurred on the convertible debentures and medium and long term notes described in Note (B) and Note (C).

H. Cash shortfall will be funded from Hydro One's revolving standby credit facility described in the notes of the financial statements of Hydro One.

I. Hydro One has recorded an adjustment to the fair value of Avista's long term debt and recorded a regulatory offset of $126 million in Regulatory Assets for the portion of the fair value adjustment to long-term debt held within regulated operations. Hydro One views the regulatory offset upon consummation of the acquisition as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

4. PRO FORMA SHARES OUTSTANDING

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding.

The calculation of the *pro forma* earnings per common share, for the three months ended March 31, 2017 and for the year ended December 31, 2016, reflect the dilutive effects of the Debentures and the assumed issuance of approximately 2 million of Hydro One's common shares estimated at C$43 million, as if the issuance of the outstanding stock based compensation awards had taken place on January 1, 2016. The basic and diluted earnings per common share and basic and diluted weighted average number of common shares outstanding for the *pro forma* reporting period is determined as follows:

(unaudited; Canadian dollars; number of shares in millions)	For the year ended December 31, 2016	For the three months ended March 31, 2017
Earnings per common share	$1.23	$0.34
Diluted earnings per common share	$1.23	$0.34
Shares outstanding		
Weighted average shares of Hydro One Limited - basic	595	595
Debenture converted common shares outstanding - basic	65	65
Pro forma weighted average shares outstanding – basic	660	660
Effect of dilutive options and other stock based compensation awards	2	2
Pro forma diluted weighted average shares of Hydro One Limited	662	662

5. CURRENCY TRANSLATION AND CLASSIFICATION ADJUSTMENTS

In the pro forma balance sheet at March 31, 2017 the assets and liabilities of Avista, which has a US$ reporting and functional currency, are translated at the exchange rate of 1.3299 which was the closing rate published by the Bank of Canada for March 31, 2017. Revenues and expenses in Avista's statement of operations are translated to Canadian dollars at average exchange rates of 1.3238 for the three months ended March 31, 2017 and 1.3245 for the year ended December 31, 2016.

Reclassifications were made to align the presentation of Avista's financial statement amounts with Hydro One's financial statement amounts in the accompanying unaudited *pro forma* financial information. No differences in accounting policies under US GAAP have been identified; however, a more detailed analysis will be completed after the Merger.

HYDRO ONE LIMITED
PRO FORMA CONSOLIDATED BALANCE SHEET
As of March 31, 2017
UNAUDITED

	Avista Historical (USD)	Foreign Exchange Impact	Avista Historical (CAD)	Reclasses (CAD)	Amount after Reclassification	
(in millions)						
Assets						
Current Assets:						
Cash and cash equivalents	26	9	35		35	
Accounts and notes receivable	179	60	239		239	
Due from related parties	-	-	-		-	
Regulator asset for energy commodity derivatives	12	3	15		15	
Materials and supplies, fuel stock and stored natural gas	47	16	63		63	
Income taxes receivable	34	11	45		45	
Other current assets	59	19	78		78	
Total current assets	357	118	475	-	475	
Property, plant and equipment	-	-	-	5,544	5,544	1
Net Utility Property:	-	-			-	
Utility plant in service	5,544	1,829	7,373	(7,373)	-	1
Construction work in progress	158	52	210	(210)	-	1
Total	5,702	1,881	7,583		-	
Less: Accumulated depreciation and amortization	(1,533)	(506)	(2,039)	2,039	-	1
Total net utility property	4,169	1,375	5,544		-	
Other Non-current Assets:						
Regulatory assets	-	-	-	881	881	2
Deferred income tax assets	-	-	-		-	
Intangible assets	-	-	-		-	
Other assets	-	-	-	126	126	3
Investment in affiliated trusts	12	3	15	(15)	-	3
Goodwill	58	19	77		77	
Other property and investments-net and other non-current assets	77	25	102	(102)	-	3
Total other non-current assets	147	47	194		1,084	
Deferred Charges:						
Regulatory assets for deferred income tax	118	39	157	(157)	-	2
Regulatory assets for pensions and other postretirement benefits	237	78	315	(315)	-	2
Other regulatory assets	137	46	183	(183)	-	2
Regulatory assets for interest rate swaps	155	51	206	(206)	-	2
Non-current regulatory asset for energy commodity derivatives	15	5	20	(20)	-	2
Other deferred charges	6	3	9	(9)	-	3
Total deferred charges	668	222	890		-	
Total assets	**5,341**	**1,762**	**7,103**		**7,103**	

HYDRO ONE LIMITED
PRO FORMA CONSOLIDATED BALANCE SHEET
As of March 31, 2017
UNAUDITED

	Avista Historical (USD)	Foreign Exchange Impact	Avista Historical (CAD)	Reclasses (CAD)	Amount after Reclassification	
Liabilities and Equity						
Current liabilities:						
Accounts payable	72	24	96	87	183	4
Current portion of long-term debt and capital leases	3	1	4		4	
Short-term borrowings	105	35	140		140	
Energy commodity derivative liabilities	7	3	10		10	
Accrued interest	29	9	38		38	
Accrued taxes other than income taxes	43	14	57		57	
Deferred natural gas costs	31	10	41		41	
Current portion of pensions and other postretirement benefits	11	4	15		15	
Due to related parties	-	-	-		-	
Other current liabilities	65	22	87	(87)	-	4
Total current liabilities	366	122	488	-	488	
	-	-			-	
Long-term debt and capital leases	1,678	554	2,232		2,232	
Long-term debt to affiliated trusts	52	17	69		69	
Regulatory liability for utility plant retirement costs	277	91	368	166	534	5
Pensions and other postretirement benefits	223	74	297		297	
Deferred income taxes	867	286	1,153		1,153	
Non-current interest rate swap derivative liabilities	23	8	31		31	
Other non-current liabilities, regulatory liabilities and deferred credits	169	55	224	(166)	58	5
Total liabilities	**3,655**	**1,207**	**4,862**	**-**	**4,862**	
	-	-			-	
Equity:	-	-			-	
Avista Corporation Shareholders' Equity:	-	-			-	
Common stock	1,073	354	1,427		1,427	
Accumulated other comprehensive loss	(7)	(3)	(10)		(10)	
Retained earnings	620	204	824		824	
Total Avista Corporation shareholders' equity	1,686	555	2,241	-	2,241	
Noncontrolling interests	-	-	-		-	
Total equity	1,686	555	2,241	-	2,241	
Total liabilities and equity	**5,341**	**1,762**	**7,103**	**-**	**7,103**	

1 Net utility property of $5,544 million to property, plant and equipment
2 Deferred charges of $890 million to regulatory assets
3 Investment in affiliates trusts and other property and investments-net and other non-current assets of $117 million to other assets.
4 Other current liabilities of $87 million to Accounts payable and other current liabilities.
5 Other non-current liabilities, regulatory liabilities and deferred credits of $166 to Long term regulatory liabilities.

HYDRO ONE LIMITED
PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS RECLASSIFICATIONS
For the three months period ended March 31, 2017
UNAUDITED

	Avista Historical (USD)	Foreign Exchange Impact	Avista Historical (CAD)	Reclasses (CAD)	Amount after Reclassification	
(in millions)						
Operating Revenues:						
Distribution	-	-	-		-	
Transmission	-	-	-		-	
Other	-	-	-	8	8	1
Utility revenues	431	139	570		570	
Non-utility revenues	6	2	8	(8)	-	1
Total operating revenues	**437**	**141**	**578**		**578**	
Operating Expenses:						
Purchased power	-	-	-	219	219	2
Operating, maintenance and administration	-	-	-	150	150	2
Depreciation and amortization	-	-	-	56	56	2
Other income-net	-	-	-	(4)	(4)	4
Utility operating expenses:	-	-	-		-	
Resource costs	166	53	219	(219)	-	2
Other operating expenses	74	25	99	(99)	-	2
Depreciation and amortization	42	14	56	(56)	-	2
Taxes other than income taxes	33	10	43	(43)	-	2
Non-utility operating expenses:	-	-	-		-	
Other operating expenses	6	2	8	(8)	-	2
Depreciation and amortization	-	-	-	-	-	2
Total operating expenses	**321**	**104**	**425**		**421**	
	-	-				
Income from operations	**116**	**37**	**153**		**157**	2
Finance charges	-	-	-	30	30	3
Interest expense	24	7	31	(31)	-	3
Interest expense to affiliated trusts	-	-	-	-	-	3
Capitalized interest	(1)	-	(1)	1	-	3
Other income-net	(3)	(1)	(4)	4	-	4
Income before income taxes	**96**	**31**	**127**		**127**	
Income tax expense	33	11	44		44	
Net income	**63**	**20**	**83**		83	

1 Non-utility revenues of $8 million to other revenue
2 Utility operating expenses and non-utility operating expenses of $425 million to operating expenses
3 Interest and other income of $30 million to finance charges
4 Other income-net of $4 million to operating expenses

HYDRO ONE LIMITED
PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS RECLASSIFICATIONS
For the year ended December 31, 2016
UNAUDITED

	Avista Historical (USD)	Foreign Exchange Impact	Avista Historical (CAD)	Reclasses (CAD)	Amount after Reclassification	
(in millions)						
Operating Revenues:						
Distribution	-	-	-		-	
Transmission	-	-	-		-	
Other	-	-	-	31	31	1
Utility revenues	1,419	460	1,879		1,879	
Non-utility revenues	24	7	31	(31)	-	1
Total operating revenues	**1,443**	**467**	**1,910**		**1,910**	
Operating Expenses:						
Purchased power	-	-	-	730	730	2
Operating, maintenance and administration	-	-	-	583	583	2
Depreciation and amortization	-	-	-	214	214	2
Other income-net	-	-	-	(13)	(13)	4
Utility operating expenses:	-	-	-		-	
Resource costs	551	179	730	(730)	-	2
Other operating expenses	316	102	418	(418)	-	2
Depreciation and amortization	161	52	213	(213)	-	2
Taxes other than income taxes	99	32	131	(131)	-	2
Non-utility operating expenses:	-	-	-		-	
Other operating expenses	26	8	34	(34)	-	2
Depreciation and amortization	1	-	1	(1)	-	2
Total operating expenses	**1,154**	**373**	**1,527**		**1,514**	
Income from operations	**289**	**94**	**383**		**396**	2
Finance charges	-	-	-	112	112	3
Interest expense	86	29	115	(115)	-	3
Interest expense to affiliated trusts	1	-	1	(1)	-	3
Capitalized interest	(3)	(1)	(4)	4	-	3
Other income-net	(10)	(3)	(13)	13	-	4
Income before income taxes	**215**	**69**	**284**		**284**	
Income tax expense	78	25	103		103	
Net income	**137**	**44**	**181**		181	

1 Non-utility revenues of $31 million to other revenue
2 Utility operating expenses and non-utility operating expenses of $1,527 million to operating expenses
3 Interest and other income of $112 million to finance charges
4 Other income-net of $13 million to operating expenses

APPENDIX A – INVESTOR PRESENTATION


hydro One
Hydro One To Acquire Avista Creating a North American Utility Leader
July 19, 2017
One of North America's Largest Electric Utilities
TSX: H

Disclaimers and cautionary statements

Unless otherwise specified, all references to "$" or "C$" in this presentation are to Canadian dollars and all references to "US$" in this presentation are references to United States dollars. Any graphs, tables or other information in this presentation demonstrating the historical performance of Hydro One Limited or Hydro One Inc. or any other entity contained in this presentation are intended only to illustrate past performance of such entities and are not necessarily indicative of future performance of Hydro One Limited, Hydro One Inc. or such entities. In this presentation, "Hydro One" refers to Hydro One Limited and its subsidiaries and other investments, taken together as a whole.

Additional Information and Where to Find It: This presentation may be deemed to be solicitation material in respect of the proposed merger transaction. Avista Corporation ("Avista") intends to file with the U.S. Securities and Exchange Commission (the "SEC") and mail to its shareholders a proxy statement in connection with the proposed merger transaction and this presentation is not a substitute for the proxy statement or any other document that Avista may send to its shareholders in connection with the proposed merger transaction. THE INVESTORS AND SECURITY HOLDERS OF AVISTA ARE URGED TO READ THE PROXY STATEMENT AND OTHER RELEVANT DOCUMENTS WHEN THEY BECOME AVAILABLE, BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION about Avista, Hydro One and the proposed merger transaction. Investors and security holders will be able to obtain these materials (when they are available) and other documents filed with the SEC free of charge at the SEC's website, www.sec.gov. In addition, a copy of Avista's proxy statement (when it becomes available) may be obtained free of charge upon request by contacting AVISTA Corporation, Avista Corp. 1411 East Mission Avenue P.O. Box 3727. Spokane, WA 99220. Avista's filings with the SEC are also available on Avista's website at: http://www.avistacorp.com. Investors and security holders may also read and copy any reports, statements and other information filed by Avista with the SEC, at the SEC public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 or visit the SEC's website for further information on its public reference room.

Participants in the Solicitation of Proxies: This presentation is not a solicitation of proxies in connection with the proposed merger transaction. However, Avista, Hydro One and certain of their respective directors, executive officers and other persons may be deemed under SEC rules to be participants in the solicitation of Avista shareholder proxies in respect of the proposed merger transaction. Information about Hydro One directors and executive officers is available in Hydro One's management information circular, filed with Canadian securities regulators on March 23, 2017, in connection with its 2017 annual meeting of shareholders and is available on its website at http://www.hydroone.com and also under its profile on SEDAR and www.sedar.com. Information regarding Avista's directors and executive officers is available in Avista's proxy statement filed with the SEC on March 31, 2017 in connection with its 2017 annual meeting of shareholders, and its Annual Report on Form 10-K for the fiscal year ended December 31, 2016 filed with the SEC on February 22, 2017, each of which may be obtained from the sources indicated in Additional Information and Where to Find It. Other information regarding persons who may be deemed participants in the proxy solicitation and a description of their direct and indirect interests (which may be different than those of Avista's investors and security holders), by security holdings or otherwise, will be contained in the proxy statement and other relevant materials filed or to be filed with the SEC when they become available.

Disclaimers and cautionary statements (continued)

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Forward-Looking Information: This presentation contains "forward-looking statements" and "forward-looking information" within the meaning of applicable securities laws of the U.S. and Canada, respectively. Statements that are not historical facts, including statements about beliefs, expectations, estimates, projections, goals, forecasts, assumptions, risks and uncertainties, are forward looking statements and forward looking information. Forward looking statements and forward looking information are often characterized by the use of words such as "believes," "estimates," "expects," "projects," "may," "intends," "plans," "anticipates," "pro forma," "predicts," "seeks," "could," "would," "will," "can," "continue" or "potential" and the negative of these terms or other comparable or similar terminology or expressions. The forward looking statements and forward looking information in this presentation include, without limitation, statements relating to Hydro One's proposed merger transaction with Avista and expectations regarding timing and benefits thereof, earnings per share accretion, increases in regulated assets and earnings, financing intentions, strength of credit metrics, scale and diversification, capital expenditures, rate base growth, industry and geographic trends and forecasts, financing plans, stakeholder commitments, stockholder and regulatory approvals, and the completion of the proposed merger transaction. These statements reflect Hydro One and Avista's management's current beliefs and are based on information currently available to the management teams. Forward looking statements and forward looking information involve significant risk, uncertainties and assumptions. Certain factors or assumptions have been applied in drawing the conclusions contained in the forward looking statements and forward looking information. Hydro One and Avista caution readers that a number of factors could cause actual results, performance or achievement to differ materially from the results discussed or implied in the forward looking statements and forward looking information. Important factors that could cause actual results, performance and results to differ materially from those indicated by any such forward looking statements and forward looking information include risks and uncertainties relating to the following: (i) the risk that Avista may be unable to obtain shareholder approval for the proposed merger transaction or that Hydro One or Avista may be unable to obtain governmental and regulatory approvals required for the proposed merger transaction, or may be unable to obtain those approvals on favorable terms; (ii) the risk that the required shareholder, governmental or regulatory approvals may delay the proposed merger transaction; (iii) the risk that a condition to the closing of the proposed merger transaction may not be satisfied or the merger agreement may be terminated prior to closing; (iv) the timing to consummate the proposed transaction; (v) disruption from the proposed merger transaction making it more difficult to maintain relationships with customers, employees, regulators or suppliers; (vi) risks associated with the loss and ongoing replacement of key personnel; (vii) the diversion of management time and attention on the transaction; (viii) general worldwide economic conditions and related uncertainties; (ix) the effect and timing of changes in laws or in governmental regulations (including environmental and tax laws and regulations); (x) the risk that financing necessary to fund the proposed merger transaction may not be obtained or may be more difficult and costly to obtain than anticipated; (xi) the impact of acquisition-related expenses; (xii) the ability to maintain an investment grade credit rating; (xiii) the ability to maintain dividend payout ratios; and (xiv) other factors discussed or referred to in the "Risk Factors" section of Hydro One's most recent annual management's discussion and analysis of financial results filed with securities regulators in Canada and available under Hydro One's profile at www.sedar.com. The foregoing list is not exhaustive and other unknown or unpredictable factors could also have a material adverse effect on the performance or results of Hydro One or Avista. Additional risks and uncertainties will be discussed in the proxy statement and other materials that Avista will file with the SEC in connection with the proposed merger transaction, or in material Hydro One will file with securities regulatory authorities in Canada. There can be no assurance that the proposed merger transaction will be completed, or if it is completed, that it will close within the anticipated time period or that the expected benefits of the proposed merger transaction will be realized. These factors should be considered carefully and undue reliance should not be placed on the forward looking statements or forward looking information, and actual outcomes and results may differ materially from what is expressed, implied or forecasted in these forward-looking statements and forward looking information. For additional information with respect to certain of the risks or factors, reference should be made to Hydro One's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities, available at www.sedar.com and Avista's filings with the SEC available at www.sec.gov. Except as required by law, each of Hydro One and Avista disclaims any intention or obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise.

Non-GAAP Measures: Hydro One Limited and Hydro One Inc. prepare and present financial statements in accordance with U.S. GAAP. This presentation refers financial measures, such as Adjusted EPS, EBITDA and "FFO" or "Funds from Operations", which are not recognized under U.S. GAAP and which may not be comparable to similar measures presented by other companies. Funds from Operations should not be considered in isolation nor as a substitute for analysis of Hydro One's financial information reported under U.S. GAAP. For more information, see "Non-GAAP Measures" in Hydro One's annual and interim Management Discussion and Analysis.

Agenda

hydroOne

1. Executive Summary of Transaction
2. Avista Overview
3. Strategic Rationale
4. Commitment to Customers, Communities and Employees
5. Indicative Timeline

Highlights of the transaction

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1

Establishes one of North America's largest regulated utilities with over C$32 billion (US$25 billion) in assets (pro forma)

2

Significant increases in stable earnings through fully regulated utility operations in constructive regulatory jurisdictions

3

Increased growth profile through expansion of Hydro One into complementary and diversified regulated assets, including natural gas LDCs

4

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing

5

Combined entity expected to maintain strong investment-grade credit ratings

6

Efficiencies through enhanced scale, innovation, shared IT systems and increased purchasing power provide cost savings opportunities

Transaction brings together two industry-leading regulated utilities with over 230 years of collective operational experience, similar corporate cultures and shared values

Transaction details

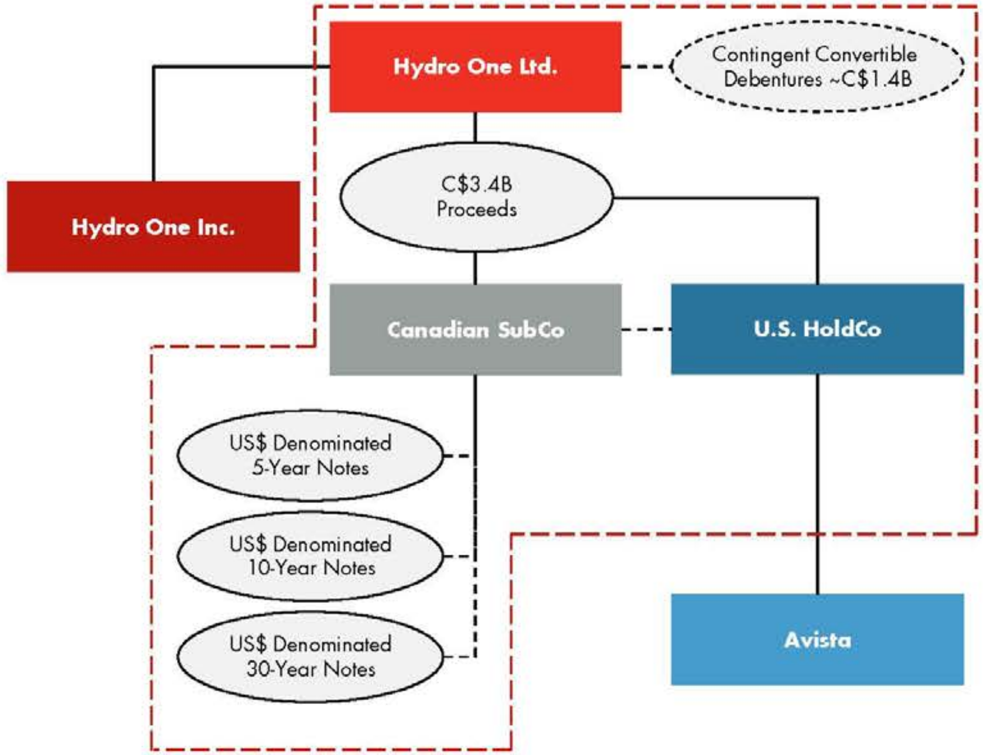
hydroOne

Key transaction terms	• Offer price of US$53.00 per Avista common share in cash – Represents a 24% premium to Avista's closing price on 18 July, 2017 of US$42.74 • Equity purchase price of US$3.4 billion (C$4.4 billion) • Total enterprise value of US$5.3 billion (C$6.7 billion), including Avista debt assumed
Financing plan	• All cash transaction • Proposed transaction contemplates use of short, medium, and long term U.S. denominated debt totaling US$2.6 billion (C$3.4 billion), as well as C$1.4 billion in Contingent Convertible Debentures to fulfill equity component requirement
Governance	• Avista management will remain in place • Formation of a subsidiary board which will represent the interests of Avista's service territories and the communities it serves • No changes in Hydro One management
Timing and approvals	• Will seek approvals from all five state regulators and FERC prior to closing • All regulatory requests for approvals will be filed concurrently • Expected closing date in the second half of 2018

Financing plan

hydroOne

Planned Transaction Financing Structure



- Transaction structure intended to provide clarity and minimize execution risk
- Planned financing contemplates a combination of 5-year, 10-year and 30-year US$ denominated notes in order to balance maturities and create a natural currency hedge
  - US$ denominated debt issued in the US by the Canadian Sub Co.
- Hydro One and Avista expected to maintain a strong investment grade status
- Contingent convertible debenture component fulfills 100% of Hydro One's equity financing requirements for the transaction

All cash transaction with a financing structure that allows Hydro One to maintain a strong investment grade status

Avista overview

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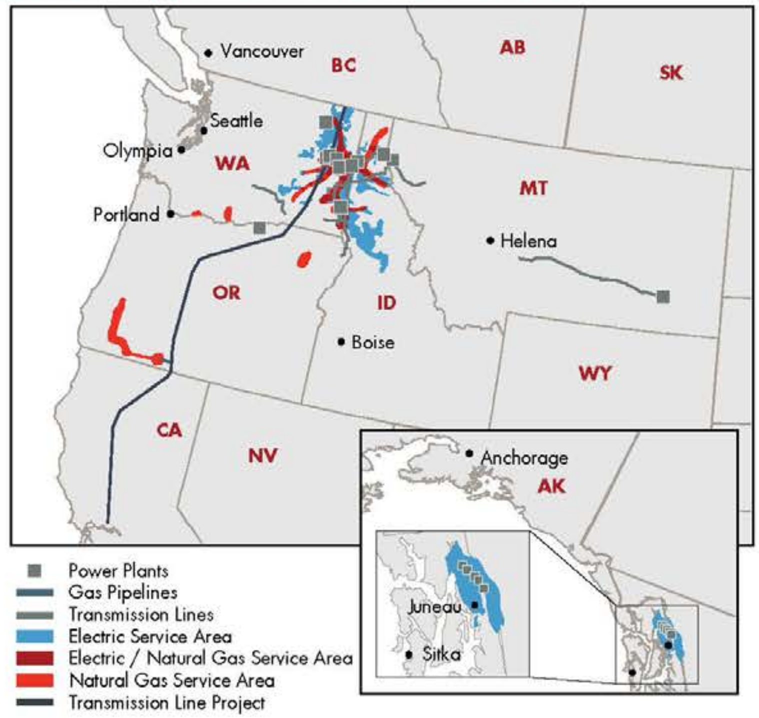
AVISTA Corp. Business Overview

- Avista is a regulated utility headquartered in Spokane, WA
  - Avista Utilities, an operating division of Avista supplying retail electric and natural gas service to customers in Washington, Idaho, Oregon and Montana service territories
    - 30,000 square miles and population of 1.6 million
    - Avista Utilities owns 2,072 MW of regulated electric generation
  - Alaska Electric Light & Power (AEL&P), serving customers in the Juneau, Alaska area
    - 16,482 electric customers
    - AEL&P owns and operates 119 MW of regulated generation capacity
- Employs ~2,000 people
- Regulated and primarily clean, renewable generation fleet

Avista Service Area

Service territories across WA, OR, ID, AK, and MT



Growing regulated business with a geographically diverse customer base, supported by one of the lowest electricity rates in the US

Note: Avista has de minimis retail operations in Montana

Avista financial & operating overview

hydroOne

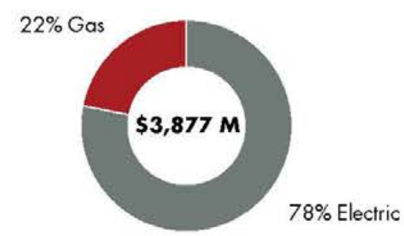
(C$ in mm)

Financial Highlights

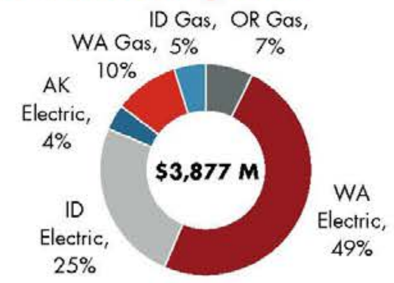
	2016A
Revenue	$1,824
EBITDA	$570
Net Income	$174

Allowed ROE		Electric	
	WA	9.50%	9.50%
	ID	9.50%	9.50%
	OR	-	9.40%
	AK	12.88%	-

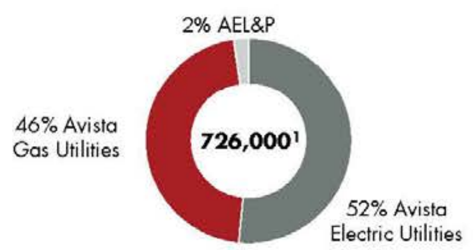
2016 Rate Base



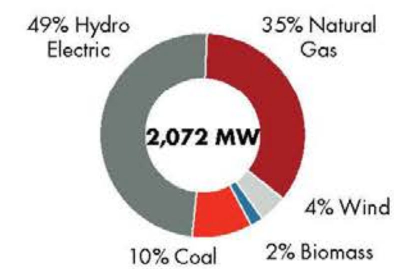
2016 Rate Base by State



2016 Customers



2016 Electric Generation[2]



Strong financial profile together with a diverse and growing regulated rate base

1. Includes combined electric and gas customers
2. Based on maximum capacity and excludes Alaska generation

Strategic rationale

hydroOne

1	**Building quality regulated asset scale**	• Maintains revenue base as nearly all regulated • Earnings and cash flow accretion in the first full year following close, excluding transaction costs • Increases Hydro One's total assets pro forma by C$6.8B (26.6%) • Establishes top tier North American utility profile • Hydro One expected to continue growing dividend and to maintain 70-80% dividend payout ratio
2	**Diversification**	• Increases geographic, economic, regulatory and asset diversification • Adds complementary and growing gas distribution • Provides exposure to regulated and predominantly clean generation
3	**Shared cultures and values**	• Strong, experienced management team with proven track record • Common and long-established history between the Companies (over 230 years of collective operational experience) • Management teams enjoy a deep cultural fit and strong dedication to their respective communities
4	**Innovation and knowledge transfer**	• Leadership position in innovation in the utility sector • Cost savings and sharing of research and development initiatives • Leveraging of technology and sharing of best practices

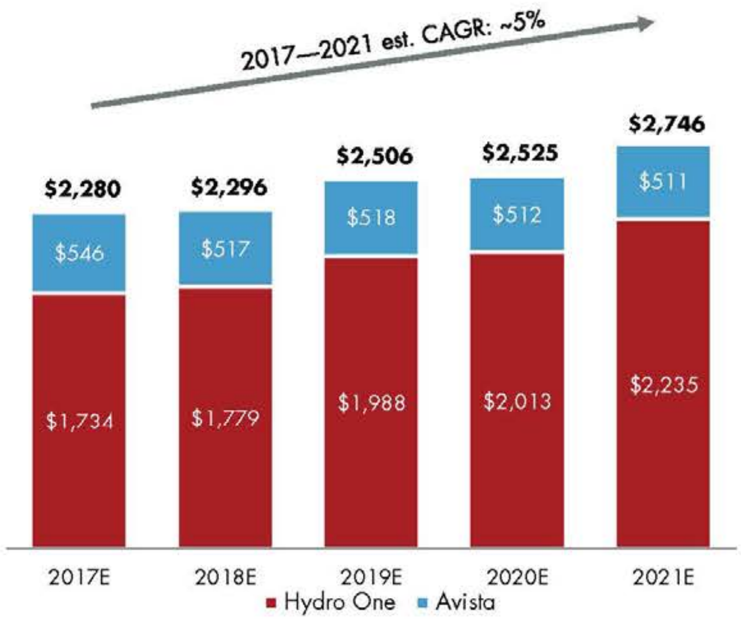
Increased scale reinforces top tier status

In accordance with Section 7.6(4) of National Instrument 44-101- *Short Form Prospectus Distributions*, all the information relating to Hydro One's comparables, and any disclosure relating to the comparables, which is contained in the presentation to be provided to potential investors, has been removed from this template version for purposes of its filing on the System for Electronic Document Analysis and Retrieval (SEDAR).

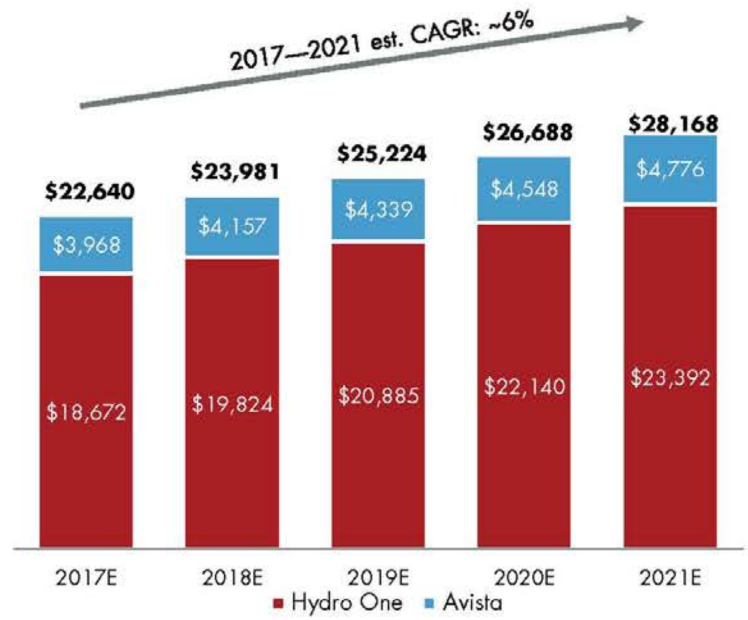
Sizeable increases in stable regulated earnings

- **Planned pro forma investments of over C$10 billion in T&D through 2021**

Pro Forma Capital Expenditures ('17E-'21E)
C$ in millions



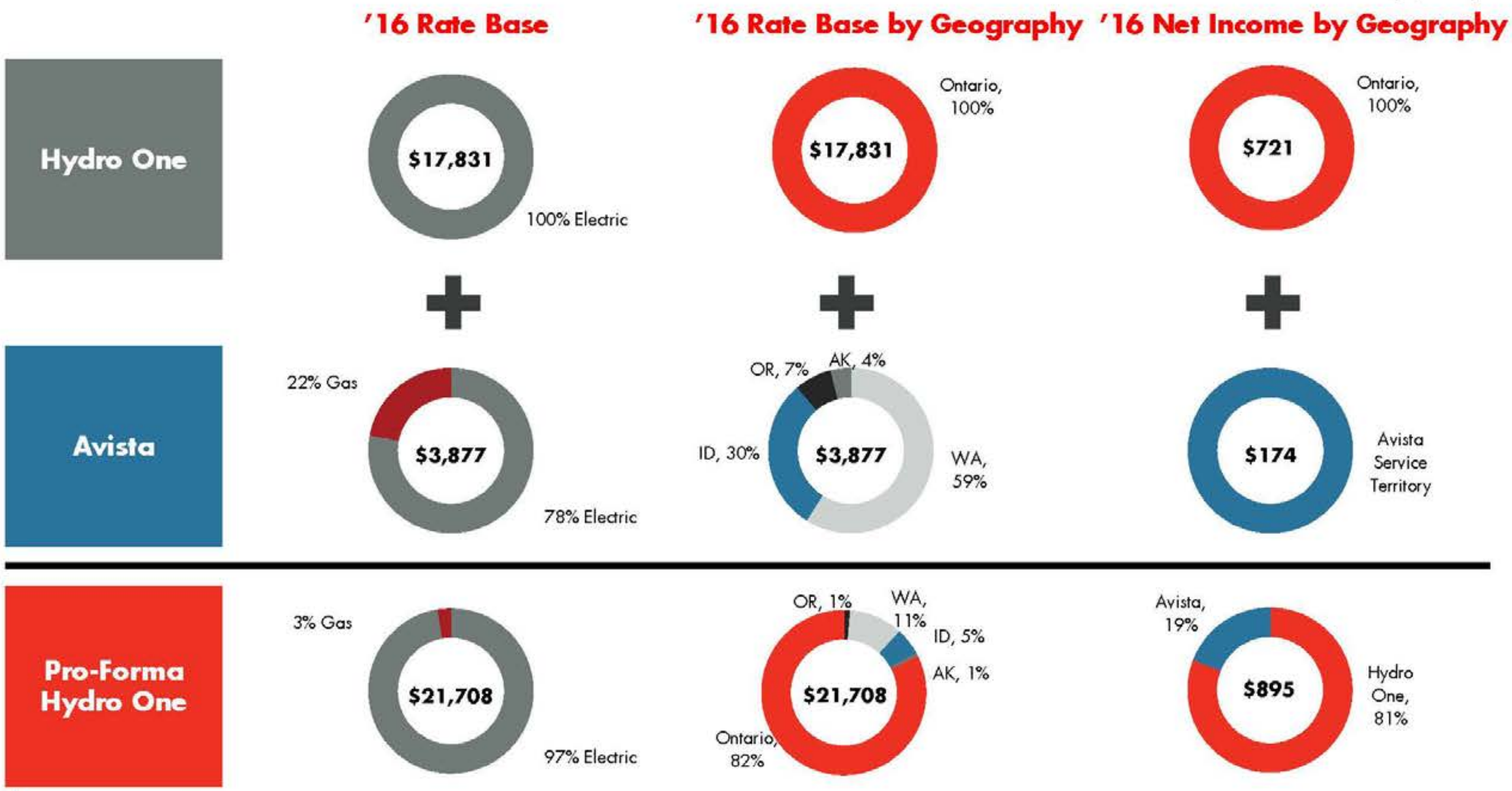
Pro Forma Rate Base ('17E-'21E)
C$ in millions



Avista's capital program will further enhance scale, strengthen quality of asset mix and reinforce Hydro One's growth profile

Diversification

(C$ in mm)



Diversification across multiple geographies, economies, regulatory jurisdictions and utility businesses enhances stability and strategic positioning

Note: Combination of Avista and Hydro One numbers as reported using an exchange rate of C$ / US$ 1.264

Regulatory diversity

(C$)

	ON	WA	ID	OR	AK
Current Rate Base[1]	$ 17,831 M	$ 2,286.6 M	$ 1,155.5 M	$ 277.6 M	$ 157.4 M
Allowed ROE	8.78%	9.50%	9.50%	9.40%	12.88%
Equity Capitalization	40.00%	48.50%	50.00%	50.00%	53.80%

Avista's assets provide an opportunity to expand and diversify the footprint to new regulatory jurisdictions with higher ROEs and attractive allowed capital structures

Note: Avista has de minimis retail operations in Montana and will seek approval from Montana regulators
1. Exchange rate of C$ / US$ 1.264

Shared culture and values

Scott Morris

- Chairman, President and CEO
- Scott is an experienced utility executive who has served in a variety of leadership positions since joining Avista in 1981
- He began his career in the company's utility marketing division and has served in leadership positions throughout the company
- Scott currently chairs the Federal Reserve Bank of San Francisco, Seattle branch, and the Board of Trustees for Gonzaga University. He also serves on the boards of Greater Spokane Incorporated, Edison Electric Institute, Washington Round Table and the American Gas Association

- Hydro One will benefit from the team assembled by Scott of well respected industry leaders who have delivered consistent shareholder value
- Seasoned leadership team at Avista with an average service of 18 years for the 13 officers
- Hydro One and Avista management teams enjoy a similar cultural fit and strong dedication to their respective communities with many volunteering on city, region and state committees/initiatives
- Both companies share a common heritage of over 100 years rooted in hydro generated electric power

Exceptional cultural fit will allow for a low risk transition and an enhanced ability to quickly find and address areas of mutual benefit that don't compromise either entities' values

Innovation and knowledge transfer

- **Avista is a proven leader in utility innovation with a deep track record of investments in advanced technologies, including energy management solutions**

Itron

- Avista is the founder of **Itron**, now a global supplier of smart meters with revenues of ~US$2 billion and total enterprise value of ~US$2.9 billion
- Sold 24.8 million units in 2016

ReliOn

- Started a fuel cell system business, **ReliOn**
- Sold to Plug Power in 2014

ecova

- Grew an energy management services company, **Ecova**, into one of the leaders in the space
- Acquired by Cofely USA, a subsidiary of ENGIE, for more than US$325 million in 2014

- Providing 272 EV charging stations as part of a 2-year pilot project
- Testing an energy storage system using battery technology

urbanova
rethinking cities

- Developing a "living laboratory for smart city innovation" in collaboration with the City of Spokane and Washington State University and others, called **Urbanova**
  - New technology development focusing in areas such as: a microgrid, solar generation, storage, energy efficient building technology, and advanced metering for electricity/gas/water

Opportunity to reduce operating costs and gain strategic benefits by leveraging and sharing innovation and best practices

Commitment to customers, communities and employees

hydroOne

Customers

- Customer rates in the markets served by Hydro One and Avista will be unaffected by transaction costs
- An enhanced transmission and distribution system will achieve operational excellence leading to cost savings over time
- Greater financial capacity will support needed additional investments in energy infrastructure and technology to provide for safe, high quality and reliable service

Communities

- Both companies will continue to take their responsibility as good corporate citizens very seriously
- This transaction will preserve and in some cases increase the commitment to philanthropy and economic development in the communities served
- Hydro One has committed to do even more, doubling Avista's current levels of community contribution

Employees

- Hydro One and Avista will maintain existing brands, headquarters and employee bases
- Avista's Board of Directors will continue to have significant Pacific Northwest representation
- Scott Morris will be CEO and Chairman of Avista, Mayo Schmidt will continue to be CEO of Hydro One

Committed to maintaining high quality, increasing efficiencies, preserving jobs, and supporting communities and regional economic development

Indicative timeline to transaction close

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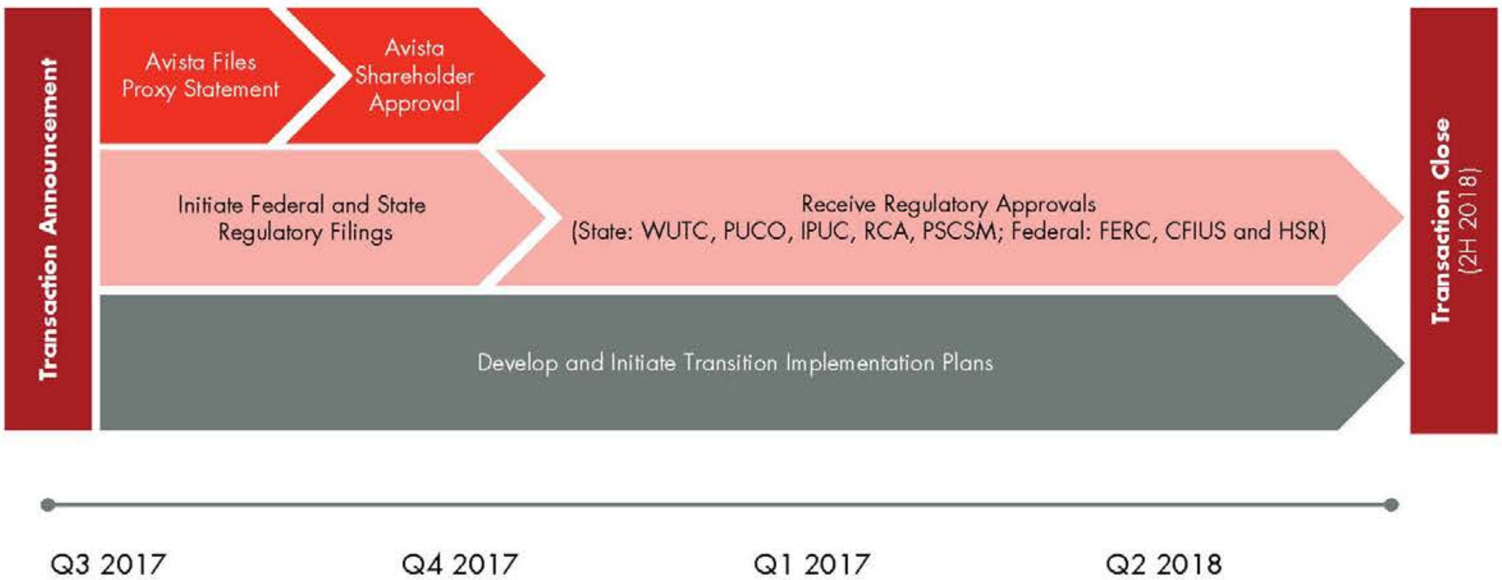

Transaction expected to close in the second half of 2018 with federal and state regulatory approval filings expected to occur concurrently for all jurisdictions

Note: WUTC (Washington Utilities and Transportation Commission), OPUC (Oregon Public Utility Commission), IPUC (Idaho Public Utilities Commission), RCA (Regulatory Commission of Alaska), PSCSM (Public Service Commission of the State of Montana), FERC (U.S. Federal Energy Regulatory Commission), CFIUS (Committee on Foreign Investment in the United States) and HSR (U.S. Hart-Scott-Rodino Antitrust Improvements Act of 1976)


hydro One
Hydro One To Acquire Avista Creating a North American Utility Leader
July 19, 2017
One of North America's Largest Electric Utilities
TSX: H

CERTIFICATE OF HYDRO ONE LIMITED

Dated: August 1, 2017

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces and territories of Canada.

HYDRO ONE LIMITED

(signed) MAYO SCHMIDT	(signed) CHRIS LOPEZ
President and Chief Executive Officer	Acting in the capacity of Chief Financial Officer

On behalf of the Board of Directors:

(signed) DAVID DENISON	(signed) PHILIP ORSINO
Director	Director

HYDRO ONE INC.

(as promoter)

(signed) MAYO SCHMIDT	(signed) CHRIS LOPEZ
President and Chief Executive Officer	Acting in the capacity of Chief Financial Officer

On behalf of the Board of Directors:

(signed) DAVID DENISON	(signed) PHILIP ORSINO
Director	Director

CERTIFICATE OF THE UNDERWRITERS

Dated: August 1, 2017

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces and territories of Canada.

RBC DOMINION SECURITIES INC.	CIBC WORLD MARKETS INC.	BMO NESBITT BURNS INC.
(Signed) DAVID DAL BELLO	(Signed) DAVID WILLIAMS	(Signed) GREG PETIT

NATIONAL BANK FINANCIAL INC.	SCOTIA CAPITAL INC.	TD SECURITIES INC.
(Signed) IAIN WATSON	(Signed) THOMAS KURFURST	(Signed) HAROLD R. HOLLOWAY

BARCLAYS CAPITAL CANADA INC.	CREDIT SUISSE SECURITIES (CANADA), INC.
(Signed) ALAN S. MAYNE	(Signed) MICHAEL COMISAROW

CANACCORD GENUITY CORP.	DESJARDINS SECURITIES INC.	LAURENTIAN BANK SECURITIES INC.	RAYMOND JAMES LTD.
(Signed) STEVE WINOKUR	(Signed) FRANÇOIS CARRIER	(Signed) THOMAS BERKY	(Signed) JAMES. A TOWER

INDUSTRIAL ALLIANCE SECURITIES INC.	WELLS FARGO SECURITIES CANADA, LTD.
(Signed) FRED WESTRA	(Signed) DARIN E. DESCHAMPS

Energy Probe Research Foundation Interrogatory # 3

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

N/A

Interrogatory:

Please file the bill impacts on the various rate classes if the Board were to approve Hydro One's application as is, with an effective date of January 2019. Energy Probe is most interested in seeing the bill impacts in 2019 that will include a rate rider for the collection of 2018 rates. Please do not include any bill mitigation measures or Fair Hydro Plan rebates.

For R2 customers, please do include the recent increase to the Rural or Remote Rate Protection program.

Response:

If the application was approved as is, but with an effective date of January 1, 2019, the 2019 bill impacts including a rider for recovery of the foregone 2018 revenue requirement would consist of i) the combined 2018 and 2019 bill impacts plus ii) the impact of recovering the forgone revenue in 2019. The 2019 bill impacts for a typical customer in each rate class, consistent with Hydro One's December 17, 2017 update to the evidence would be approximately as shown in the table below. The bill impacts in other years would remain largely unchanged, except for the small impact associated with recovering regulatory asset balances over 4 years instead of 5 years.

2019 bill impacts assuming 2018 rates are approved as filed, but implemented on January 1, 2019						
Rate Class	**Monthly Consumption (kWh)**	**Monthly Peak (kW)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**
UR	750		$4.39	13.6%	$10.70	8.2%
R1	750		$8.59	16.6%	$13.90	9.1%
R2	750		$13.65	27.7%	$18.62	12.3%
Seasonal	352		$7.58	12.7%	$9.41	8.6%
GSe	2,000		$21.26	15.1%	$26.99	6.4%
UGe	2,000		$11.44	15.0%	$16.14	4.6%
GSd	36,104	124	$399.66	19.5%	$524.92	7.3%
UGd	50,525	135	$334.70	26.3%	$573.47	7.0%
St Lgt	517		$7.20	13.7%	$10.31	8.5%
Sen Lgt	71		$1.97	17.6%	$2.45	11.7%
USL	364		($0.19)	-0.4%	$0.82	0.9%
DGen	1,328	13	$115.50	47.5%	$140.38	31.0%
ST	1,601,036	3,091	$1,302.02	30.2%	$4,923.91	2.2%

Energy Probe Research Foundation Interrogatory # 4

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

C1-01-05 Page: 7-8

Interrogatory:

Has Hydro One's forecast of LEAP spending changed as a result of the recently passed Fair Hydro Plan?

Response:

Hydro One's forecast of LEAP spending has not changed as a result of the recently passed Fair Hydro Plan. In the eight months after implementation, demand for LEAP funding has remained consistent relative to prior years.

Power Workers' Union Interrogatory # 2

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

N/A

Interrogatory:

Assuming that the Board approves the application as requested:

a) What bill impact does Hydro One forecast for a customer in the R1 rate class consuming 750 kWh per month for each of the years of the application following 2018, taking account of the effects of the FHP?

b) What is the forecast of the bill impact for these customers in each of the years, if the inflation assumption is 0% for each year?

Response:

a) The 2018 bill impact for a typical R1 customer taking into account the FHP is provided in the response to I-04-PWU-004.

b) It is Hydro One's understanding that the government of Ontario's commitment to keep bill impacts to the "rate of inflation" would be implemented by making adjustments to the price of electricity. Assuming that inflation was at 0% for each year, this would mean that electricity prices would stay constant. The bill impacts calculated in this application also assume that electricity prices (and all other non-distribution related charges) are held constant, consistent with Board policy for calculating bill impacts, and therefore the forecast of bill impacts for these customers would be as currently presented in the application.

Power Workers' Union Interrogatory # 3

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

N/A

Interrogatory:

a) Does Hydro One agree that the Board prescribed Bill Impact calculations do not accurately reflect the actual impact that the application will have on the bills received by customers of Hydro One who are subject to the FHP?

g) In particular, does Hydro One agree that adjustment to the commodity price from year to year is an intrinsic element of the operation of the FHP for each year of the application?

Response:

a) Hydro One believes that the Board prescribed calculation of bill impacts does accurately reflect the impact of the changes in distribution rates proposed in the application, however, we agree that the calculated bill impacts do not reflect the actual impact on the bills received by residential customers that are subject to distribution charge reductions under the FHP. The bill impacts including the impact of the FHP are provided in the response to Exhibit I-4-PWU-4.

g) It is Hydro One's understanding that commodity prices may be adjusted until 2022 to keep bill increases in line with inflation.

Power Workers' Union Interrogatory # 4

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

N/A

Interrogatory:

a) Please re-file Exhibit H1, Tab 4, Schedule 1, including attachments thereto, and Exhibit A Tab 3 Schedule 1, Table 17, reflecting the bill impacts after the effects of the FHP are accounted for. Provide illustrative examples of the calculation of the bill impacts for each year of the application. Please indicate what assumptions have been made, and the basis for those assumptions.

Response:

a) The bill impact tables and attachments in Exhibit H1, Tab 4, Schedule 1 apply the Fair Hydro Plan elements that were in effect at the time of filing in June 2017. This consists of a partial reduction to commodity charges, the removal of the Ontario Electricity Support Program (OESP) regulatory charge, and the Ontario Rebate for Electricity Consumers (OREC) on eligible bills. A revision of these tables are provided as attachments to this response which include the remaining Fair Hydro Plan elements that are now in effect; fully reduced Regulated Price Protection (RPP) commodity charges, Distribution Rate Protection (DRP) on R1 and R2 bills, and reduced Rural Rate Protection regulatory charges. The Fair Hydro Plan also includes a First Nations Delivery credit, which is not illustrated in the attachments since Exhibit H1, Tab 4, Schedule 1 does not include First Nations bill simulations.

The attachments to this response are as follows:

- Attachment 1: Revision of Bill Impact Tables in H1-04-01
- Attachment 2: Bill Impact 2018 with Fair Hydro Plan
- Attachment 3: Bill Impact 2019 with Fair Hydro Plan
- Attachment 4: Bill Impact 2020 with Fair Hydro Plan
- Attachment 5: Bill Impact 2021 with Fair Hydro Plan
- Attachment 6: Bill Impact 2022 with Fair Hydro Plan

Bill Impacts with FHP

TABLE 1 - DISTRIBUTION AND TOTAL BILL IMPACTS BY RATE CLASS FOR HYDRO ONE CUSTOMERS

				2017		2018				2019		2020				2021				2022			
Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2017 Dx Bill	2017 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in DX Bill ($)	Change in Total Bill (%)	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$ 28.69	$ 69.07	$ 1.77	6.2%	$ 2.97	4.3%	$ 2.44	3.5%	$ 2.97	9.0%	$ 3.12	4.2%	$ 0.82	2.3%	$ 0.76	1.0%	$ 0.70	1.9%	$ 0.73	0.9%
	Typical	750		$ 32.33	$ 116.16	$ 1.26	3.9%	$ 3.71	3.2%	$ 1.20	1.0%	$ 1.10	3.1%	$ 1.15	0.9%	$ 0.82	2.3%	$ 0.64	0.5%	$ 0.70	1.9%	$ 0.73	0.6%
	Average	755		$ 32.37	$ 116.75	$ 1.26	3.9%	$ 3.72	3.2%	$ 1.18	1.0%	$ 1.07	3.1%	$ 1.13	0.9%	$ 0.82	2.3%	$ 0.64	0.5%	$ 0.70	1.9%	$ 0.73	0.6%
	High	1,400		$ 38.24	$ 192.68	$ 0.44	1.1%	$ 4.91	2.6%	$ (0.82)	-0.4%	$ (1.96)	-5.2%	$ (2.06)	-1.0%	$ 0.82	2.3%	$ 0.45	0.2%	$ 0.70	1.9%	$ 0.73	0.4%
R1	Low	400		$ 37.17	$ 84.03	$ (0.73)	-2.0%	$ 0.20	0.2%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.06)	-0.1%	$ -	0.0%	$ -	0.0%
	Typical	750		$ 37.10	$ 122.38	$ (0.65)	-1.8%	$ 1.13	0.9%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.12)	-0.1%	$ -	0.0%	$ -	0.0%
	Average	920		$ 37.07	$ 141.00	$ (0.61)	-1.7%	$ 1.58	1.1%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.14)	-0.1%	$ -	0.0%	$ -	0.0%
	High	1,800		$ 36.89	$ 237.41	$ (0.42)	-1.1%	$ 3.91	1.6%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.28)	-0.1%	$ -	0.0%	$ -	0.0%
R2	Low	450		$ 37.79	$ 91.24	$ (1.38)	-3.6%	$ (0.52)	-0.6%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.04)	0.0%	$ -	0.0%	$ -	0.0%
	Typical	750		$ 37.79	$ 124.88	$ (1.37)	-3.6%	$ 0.10	0.1%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.06)	0.0%	$ -	0.0%	$ -	0.0%
	Average	1,152		$ 37.79	$ 169.97	$ (1.37)	-3.6%	$ 0.93	0.5%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.09)	-0.1%	$ -	0.0%	$ -	0.0%
	High	2,300		$ 37.79	$ 298.72	$ (1.36)	-3.6%	$ 3.30	1.1%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ (0.19)	-0.1%	$ -	0.0%	$ -	0.0%
Seasonal	Low	50		$ 40.31	$ 48.94	$ 3.21	8.0%	$ 3.44	7.0%	$ 4.19	8.4%	$ 4.54	9.5%	$ 4.76	8.4%	$ 4.71	9.0%	$ 4.95	8.0%	$ 5.45	9.6%	$ 5.72	8.6%
	Average	352		$ 59.58	$ 102.56	$ 2.10	3.5%	$ 2.68	2.6%	$ 1.98	2.0%	$ 1.85	2.9%	$ 1.94	1.8%	$ 1.03	1.6%	$ 1.09	1.0%	$ 1.43	2.1%	$ 1.50	1.4%
	High	1,000		$ 100.92	$ 217.60	$ (0.29)	-0.3%	$ 1.06	0.5%	$ (2.75)	-1.3%	$ (3.92)	-4.0%	$ (4.12)	-1.9%	$ (6.88)	-7.3%	$ (7.20)	-3.4%	$ (7.19)	-8.3%	$ (7.55)	-3.7%
GSe	Low	1,000		$ 84.80	$ 207.68	$ 3.68	4.3%	$ 4.40	2.1%	$ 3.04	1.5%	$ 2.68	2.9%	$ 2.81	1.3%	$ 2.40	2.5%	$ 2.33	1.1%	$ 2.36	2.4%	$ 2.48	1.1%
	Typical	2,000		$ 141.00	$ 384.24	$ 6.40	4.5%	$ 7.80	2.0%	$ 5.44	1.5%	$ 4.68	3.1%	$ 4.91	1.2%	$ 4.30	2.7%	$ 4.13	1.0%	$ 4.16	2.6%	$ 4.37	1.1%
	Average	1,982		$ 139.99	$ 381.07	$ 6.35	4.5%	$ 7.74	2.0%	$ 5.40	1.5%	$ 4.64	3.1%	$ 4.88	1.2%	$ 4.27	2.7%	$ 4.10	1.0%	$ 4.13	2.6%	$ 4.33	1.1%
	High	15,000		$ 871.60	$ 2,679.53	$ 41.76	4.8%	$ 51.91	1.9%	$ 36.64	1.4%	$ 30.68	3.2%	$ 32.21	1.2%	$ 29.00	3.0%	$ 27.57	1.0%	$ 27.56	2.7%	$ 28.94	1.0%
UGe	Low	1,000		$ 50.07	$ 169.08	$ 1.65	3.3%	$ 2.13	1.3%	$ 1.79	1.1%	$ 1.53	2.9%	$ 1.61	0.9%	$ 1.35	2.5%	$ 1.13	0.6%	$ 1.32	2.3%	$ 1.39	0.8%
	Typical	2,000		$ 76.17	$ 311.91	$ 3.38	4.4%	$ 4.35	1.4%	$ 2.99	1.0%	$ 2.43	2.9%	$ 2.55	0.8%	$ 2.25	2.6%	$ 1.78	0.6%	$ 2.12	2.4%	$ 2.23	0.7%
	Average	2,759		$ 95.98	$ 420.31	$ 4.69	4.9%	$ 6.03	1.4%	$ 3.90	1.0%	$ 3.11	3.0%	$ 3.27	0.8%	$ 2.93	2.7%	$ 2.28	0.5%	$ 2.73	2.5%	$ 2.86	0.7%
	High	15,000		$ 415.47	$ 2,168.62	$ 25.87	6.2%	$ 33.18	1.5%	$ 18.59	0.9%	$ 14.13	3.1%	$ 14.84	0.7%	$ 13.95	2.9%	$ 10.31	0.5%	$ 12.52	2.6%	$ 13.15	0.6%
GSd	Low	15,000	60	$ 1,038.92	$ 2,940.53	$ 70.04	6.7%	$ 86.34	2.9%	$ 38.78	1.4%	$ 34.71	3.0%	$ 39.22	1.3%	$ 31.89	2.7%	$ 31.55	1.0%	$ 24.92	2.0%	$ 28.16	0.9%
	Average	36,104	124	$ 2,044.78	$ 6,496.61	$ 137.72	6.7%	$ 170.51	2.6%	$ 78.36	1.3%	$ 69.59	3.1%	$ 78.64	1.2%	$ 66.44	2.8%	$ 65.51	0.9%	$ 51.34	2.1%	$ 58.01	0.8%
	High	175,000	500	$ 7,938.38	$ 28,934.76	$ 551.17	6.9%	$ 682.84	2.4%	$ 310.92	1.2%	$ 274.55	3.1%	$ 310.24	1.0%	$ 255.45	2.8%	$ 251.29	0.8%	$ 195.82	2.1%	$ 221.28	0.7%
UGd	Low	15,000	60	$ 626.92	$ 2,504.68	$ 51.84	8.3%	$ 87.92	3.5%	$ 23.44	1.0%	$ 21.10	3.0%	$ 23.84	0.9%	$ 19.69	2.7%	$ 17.35	0.7%	$ 13.47	1.8%	$ 15.22	0.6%
	Average	50,525	135	$ 1,273.73	$ 7,223.42	$ 127.57	10.0%	$ 210.17	2.9%	$ 50.24	0.8%	$ 44.60	3.1%	$ 50.39	0.7%	$ 43.13	2.8%	$ 37.46	0.5%	$ 28.62	1.8%	$ 32.34	0.4%
	High	175,000	500	$ 4,472.34	$ 25,215.35	$ 445.29	10.0%	$ 747.66	3.0%	$ 180.65	0.8%	$ 158.95	3.1%	$ 179.61	0.7%	$ 151.91	2.9%	$ 130.80	0.5%	$ 98.92	1.8%	$ 111.78	0.4%
St Lgt	Low	100		$ 13.64	$ 25.42	$ 0.20	1.4%	$ 0.41	1.6%	$ 0.48	2.0%	$ 0.45	3.1%	$ 0.47	1.8%	$ 0.70	4.7%	$ 0.56	2.1%	$ 0.39	2.5%	$ 0.41	1.5%
	Average	517		$ 52.46	$ 111.37	$ 2.07	3.9%	$ 3.23	2.9%	$ 1.94	1.8%	$ 1.78	3.2%	$ 1.87	1.6%	$ 1.78	3.1%	$ 0.97	0.8%	$ 1.56	2.4%	$ 1.64	1.4%
	High	2,000		$ 190.53	$ 436.62	$ 8.73	4.6%	$ 13.26	3.0%	$ 7.13	1.7%	$ 6.53	3.2%	$ 6.86	1.5%	$ 5.64	2.6%	$ 2.42	0.5%	$ 5.71	2.6%	$ 6.00	1.3%
Sen Lgt	Low	20		$ 5.13	$ 7.82	$ 0.42	8.2%	$ 0.48	6.1%	$ 0.38	4.9%	$ 0.35	5.8%	$ 0.36	4.2%	$ 0.21	3.3%	$ 0.18	2.0%	$ 0.26	4.1%	$ 0.28	3.0%
	Average	71		$ 11.19	$ 19.70	$ 0.48	4.3%	$ 0.65	3.3%	$ 0.80	4.1%	$ 0.72	5.8%	$ 0.75	3.6%	$ 0.36	2.7%	$ 0.25	1.1%	$ 0.55	4.1%	$ 0.58	2.6%
	High	200		$ 26.50	$ 49.76	$ 0.62	2.4%	$ 1.07	2.1%	$ 1.86	3.8%	$ 1.66	5.7%	$ 1.74	3.3%	$ 0.73	2.4%	$ 0.42	0.8%	$ 1.29	4.1%	$ 1.35	2.5%
USL	Low	100		$ 38.53	$ 51.62	$ (0.93)	-2.4%	$ (0.88)	-1.7%	$ 0.80	1.7%	$ 1.24	3.2%	$ 1.30	2.5%	$ 0.76	1.9%	$ 0.79	1.5%	$ 0.99	2.5%	$ 1.04	1.9%
	Average	364		$ 46.03	$ 88.29	$ (0.92)	-2.0%	$ (0.65)	-0.7%	$ 0.98	1.2%	$ 1.42	3.1%	$ 1.50	1.7%	$ 0.89	1.9%	$ 0.91	1.0%	$ 1.15	2.4%	$ 1.21	1.3%
	High	1,000		$ 64.09	$ 181.28	$ (0.91)	-1.4%	$ (0.08)	0.0%	$ 1.43	0.8%	$ 1.87	2.9%	$ 1.96	1.1%	$ 1.21	1.8%	$ 1.20	0.6%	$ 1.53	2.3%	$ 1.61	0.9%
DGen	Low	300	10	$ 222.88	$ 293.89	$ 37.63	16.9%	$ 45.55	15.5%	$ 33.91	11.3%	$ 8.23	2.8%	$ 9.30	2.5%	$ 7.65	2.5%	$ 8.82	2.3%	$ 6.77	2.2%	$ 7.65	1.9%
	Average	1,328	13	$ 243.13	$ 427.70	$ 36.68	15.1%	$ 45.39	10.6%	$ 44.08	10.5%	$ 10.69	3.3%	$ 12.08	2.3%	$ 9.18	2.8%	$ 10.58	2.0%	$ 8.12	2.4%	$ 9.18	1.7%
	High	5,000	100	$ 858.13	$ 1,597.33	$ (18.57)	-2.2%	$ 9.34	0.6%	$ 339.10	23.8%	$ 82.26	7.0%	$ 92.95	4.7%	$ 76.52	6.1%	$ 88.19	4.2%	$ 67.68	5.0%	$ 76.48	3.5%
ST	Low	200,000	500	$ 1,820.52	$ 25,882.98	$ (30.70)	-1.7%	$ 67.02	0.3%	$ 52.55	0.2%	$ 55.86	3.0%	$ 63.13	0.2%	$ 32.44	1.7%	$ 92.76	0.4%	$ 50.62	2.6%	$ 57.20	0.2%
	Average	1,601,036	3,091	$ 4,304.47	$ 189,505.17	$ 526.12	12.2%	$ 1,223.27	0.6%	$ 196.59	0.1%	$ 179.74	3.6%	$ 203.10	0.1%	$ 121.02	2.4%	$ 468.85	0.2%	$ 152.76	3.0%	$ 172.62	0.1%
	High	4,000,000	10,000	$ 12,310.42	$ 490,421.21	$ 628.49	5.1%	$ 2,744.34	0.6%	$ 580.66	0.1%	$ 510.04	3.8%	$ 576.35	0.1%	$ 374.52	2.7%	$ 1,545.15	0.3%	$ 445.07	3.1%	$ 502.93	0.1%
AUR	Low	350		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 0.81	2.6%	$ 0.85	1.2%
	Typical	750		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 0.81	2.6%	$ 0.85	0.7%
	Average	505		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 0.81	2.6%	$ 0.85	1.0%
	High	1,400		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 0.81	2.6%	$ 0.85	0.5%
AUGe	Low	1,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 9.71	20.4%	$ 10.20	6.2%
	Typical	2,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 13.31	20.5%	$ 13.98	4.7%
	Average	2,695		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 15.81	20.5%	$ 16.60	4.3%
	High	15,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 60.11	20.6%	$ 63.12	3.1%
AUGd	Low	15,000	60	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	See Table 2 for Bill Impacts on Acquired Customers				$ 154.15	34.5%	$ 174.19	7.6%
	Average	61,239	177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 306.86	33.6%	$ 346.75	4.3%
	High	175,000	500	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 728.44	33.1%	$ 823.14	3.7%
AR	Low	400		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 1.06	2.6%	$ 1.11	1.3%
	Typical	750		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 1.06	2.6%	$ 1.11	0.9%
	Average	634		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 1.06	2.6%	$ 1.11	1.0%
	High	1,800		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 1.06	2.6%	$ 1.11	0.5%
AGSe	Low	1,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 3.64	6.1%	$ 3.82	2.1%
	Typical	2,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 4.94	6.3%	$ 5.19	1.7%
	Average	1,988		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 4.92	6.3%	$ 5.17	1.7%
	High	15,000		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 21.84	6.8%	$ 22.93	1.1%
AGSd	Low	15,000	60	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 115.81	22.2%	$ 130.87	5.5%
	Average	53,895	152	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 222.58	22.2%	$ 251.51	3.4%
	High	175,000	500	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					$ 626.43	22.1%	$ 707.87	3.0%

* Refer to H1-04-01 Table 2 for Bill Impacts on customers formerly served by NDPI, HCHI and WHSI

TABLE 2- DISTRIBUTION AND TOTAL BILL IMPACTS BY RATE CLASS FOR ACQUIRED CUSTOMERS

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2020 Dx Bill	2020 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
Former Woodstock Hydro Customers to Hydro One Rate Classes									
AUR	**Low**	350		$ 29.68	$ 70.14	$ 1.10	3.7%	$ 1.94	2.8%
	Typical	750		$ 29.68	$ 113.44	$ 1.10	3.7%	$ 2.85	2.5%
	Average	600		$ 29.68	$ 97.20	$ 1.10	3.7%	$ 2.51	2.6%
	High	1,400		$ 29.68	$ 183.80	$ 1.10	3.7%	$ 4.31	2.3%
AUGe	**Low**	1,000		$ 39.24	$ 156.78	$ 8.42	21.5%	$ 8.54	5.4%
	Typical	2,000		$ 53.54	$ 286.28	$ 11.52	21.5%	$ 11.49	4.0%
	Average	2,695		$ 63.48	$ 376.29	$ 13.67	21.5%	$ 13.54	3.6%
	High	15,000		$ 239.44	$ 1,969.81	$ 51.82	21.6%	$ 49.86	2.5%
AUGd	**Low**	15,000	60	$ 291.67	$ 2,220.57	$ 150.66	51.7%	$ 61.53	2.8%
	Average	61,239	177	$ 590.25	$ 7,999.21	$ 309.46	52.4%	$ 34.26	0.4%
	High	175,000	500	$ 1,414.51	$ 22,517.81	$ 747.87	52.9%	$ (45.32)	-0.2%
St Lgt	**Average**	76,826	211	$ 5,077.52	$ 14,610.42	$ 3,139.22	61.8%	$ 3,500.58	24.0%
USL	**Average**	1,545		$ 29.11	$ 210.73	$ 55.10	189.3%	$ 60.46	28.7%
ST	**Low**	750,000	1,500	$ 1,869.86	$ 81,691.01	$ 1,373.82	73.5%	$ 9,289.84	11.4%
	Average	1,037,334	2,075	$ 6,142.04	$ 124,884.52	$ (2,143.32)	-34.9%	$ 403.76	0.3%
	High	2,000,000	3,500	$ 10,007.06	$ 235,854.39	$ (4,137.39)	-41.3%	$ 122.91	0.1%
Former Norfolk Power Customers to Hydro One Rate Cl				$ -	$ -				
AR	**Low**	400		$ 36.59	$ 82.31	$ 3.84	10.5%	$ 5.66	6.9%
	Typical	750		$ 36.91	$ 120.09	$ 3.53	9.6%	$ 6.75	5.6%
	Average	570		$ 36.74	$ 100.66	$ 3.69	10.0%	$ 6.19	6.1%
	High	1,800		$ 37.85	$ 233.43	$ 2.58	6.8%	$ 10.03	4.3%
AGSe	**Low**	1,000		$ 65.34	$ 183.82	$ (5.62)	-8.6%	$ (5.42)	-2.9%
	Typical	2,000		$ 81.44	$ 313.08	$ (2.92)	-3.6%	$ (0.33)	-0.1%
	Average	2,182		$ 84.38	$ 336.82	$ (2.43)	-2.9%	$ 0.44	0.1%
	High	15,000		$ 290.74	$ 2,004.91	$ 32.18	11.1%	$ 54.32	2.7%
AGSd	**Low**	15,000	60	$ 494.35	$ 2,382.69	$ 21.87	4.4%	$ (4.27)	-0.2%
	Average	57,223	161	$ 919.05	$ 7,705.81	$ 118.76	12.9%	$ 56.28	0.7%
	High	175,000	500	$ 2,345.39	$ 23,072.99	$ 444.14	18.9%	$ 259.87	1.1%
St Lgt	**Average**	1,368	4	$ 71.92	$ 230.51	$ 79.05	109.9%	$ 87.04	37.8%
Sen Lgt	**Average**	126		$ 15.25	$ 29.89	$ 5.90	38.7%	$ 6.27	21.0%
USL	**Average**	945		$ 24.16	$ 130.66	$ 41.88	173.4%	$ 46.65	35.7%
Former Haldimand County Hydro Customers to Hydro (				$ -	$ -				
AR	**Low**	400		$ 35.42	$ 82.15	$ 5.01	14.1%	$ 5.82	7.1%
	Typical	750		$ 35.56	$ 120.68	$ 4.87	13.7%	$ 6.16	5.1%
	Average	694		$ 35.54	$ 114.52	$ 4.89	13.8%	$ 6.11	5.3%
	High	1,800		$ 35.98	$ 236.26	$ 4.45	12.4%	$ 7.19	3.0%
AGSe	**Low**	1,000		$ 45.87	$ 165.05	$ 13.85	30.2%	$ 13.35	8.1%
	Typical	2,000		$ 65.07	$ 301.00	$ 13.45	20.7%	$ 11.75	3.9%
	Average	1,819		$ 61.60	$ 276.45	$ 13.52	22.0%	$ 12.04	4.4%
	High	15,000		$ 314.67	$ 2,068.39	$ 8.25	2.6%	$ (9.16)	-0.4%
AGSd	**Low**	15,000	60	$ 325.75	$ 2,261.41	$ 190.48	58.5%	$ 117.02	5.2%
	Average	50,917	143	$ 662.74	$ 6,859.29	$ 283.43	42.8%	$ 73.11	1.1%
	High	175,000	500	$ 2,107.57	$ 23,422.83	$ 681.96	32.4%	$ (89.98)	-0.4%
St Lgt	**Average**	105,612	274	$ 14,406.60	$ 27,946.23	$ (3,113.00)	-21.6%	$ (3,047.56)	-10.9%
Sen Lgt	**Average**	131		$ 26.50	$ 42.11	$ (4.65)	-17.5%	$ (4.67)	-11.1%
USL	**Average**	551		$ 20.89	$ 82.79	$ 33.18	158.8%	$ 34.75	42.0%

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2017 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$69.07	$1.77	6.18%	$2.97	4.31%
	Typical	750		$116.16	$1.26	3.91%	$3.71	3.20%
	Average	755		$116.75	$1.26	3.89%	$3.72	3.19%
	High	1,400		$192.68	$0.44	1.15%	$4.91	2.55%
R1	Low	400		$84.03	($0.73)	-1.96%	$0.20	0.24%
	Typical	750		$122.38	($0.65)	-1.75%	$1.13	0.92%
	Average	920		$141.00	($0.61)	-1.66%	$1.58	1.12%
	High	1,800		$237.41	($0.42)	-1.14%	$3.91	1.65%
R2	Low	450		$91.24	($1.38)	-3.64%	($0.52)	-0.57%
	Typical	750		$124.88	($1.37)	-3.63%	$0.10	0.08%
	Average	1,152		$169.97	($1.37)	-3.62%	$0.93	0.55%
	High	2,300		$298.72	($1.36)	-3.59%	$3.30	1.10%
Seasonal	Low	50		$48.94	$3.21	7.97%	$3.44	7.03%
	Average	352		$102.56	$2.10	3.52%	$2.68	2.62%
	High	1,000		$217.60	($0.29)	-0.29%	$1.06	0.49%
GSe	Low	1,000		$207.68	$3.68	4.34%	$4.40	2.12%
	Typical	2,000		$384.24	$6.40	4.54%	$7.80	2.03%
	Average	1,982		$381.07	$6.35	4.54%	$7.74	2.03%
	High	15,000		$2,679.53	$41.76	4.79%	$51.91	1.94%
UGe	Low	1,000		$169.08	$1.65	3.29%	$2.13	1.26%
	Typical	2,000		$311.91	$3.38	4.43%	$4.35	1.39%
	Average	2,759		$420.31	$4.69	4.89%	$6.03	1.44%
	High	15,000		$2,168.62	$25.87	6.23%	$33.18	1.53%
GSd	Low	15,000	60	$2,940.53	$70.04	6.74%	$86.34	2.94%
	Average	36,104	124	$6,496.61	$137.72	6.74%	$170.51	2.62%
	High	175,000	500	$28,934.76	$551.17	6.94%	$682.84	2.36%
UGd	Low	15,000	60	$2,504.68	$51.84	8.27%	$87.92	3.51%
	Average	50,525	135	$7,223.42	$127.57	10.02%	$210.17	2.91%
	High	175,000	500	$25,215.35	$445.29	9.96%	$747.66	2.97%
St Lgt	Low	100		$25.42	$0.20	1.44%	$0.41	1.62%
	Average	517		$111.37	$2.07	3.94%	$3.23	2.90%
	High	2,000		$436.62	$8.73	4.58%	$13.26	3.04%
Sen Lgt	Low	20		$7.82	$0.42	8.16%	$0.48	6.15%
	Average	71		$19.70	$0.48	4.26%	$0.65	3.28%
	High	200		$49.76	$0.62	2.35%	$1.07	2.14%
USL	Low	100		$51.62	($0.93)	-2.40%	($0.88)	-1.71%
	Average	364		$88.29	($0.92)	-2.00%	($0.65)	-0.73%
	High	1,000		$181.28	($0.91)	-1.42%	($0.08)	-0.04%
DGen	Low	300	10	$293.89	$37.63	16.88%	$45.55	15.50%
	Average	1,328	13	$427.70	$36.68	15.09%	$45.39	10.61%
	High	5,000	100	$1,597.33	($18.57)	-2.16%	$9.34	0.58%
ST	Low	200,000	500	$25,882.98	($30.70)	-1.69%	$67.02	0.26%
	Average	1,601,036	3,091	$189,505.17	$526.12	12.22%	$1,223.27	0.65%
	High	4,000,000	10,000	$490,421.21	$628.49	5.11%	$2,744.34	0.56%

2018 Bill Impacts (Low Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	369.95
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	38.48%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**38.48%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		20.53%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.85%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		11.54%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**41.06%**	**39.91%**
Service Charge	1	24.78	24.78	1	27.71	27.71	2.93	11.82%	39.56%	38.46%
Fixed Deferral/Variance Account Rider	1	0.7200	0.72	1	0.0070	0.01	-0.71	-99.03%	0.01%	0.01%
Distribution Volumetric Rate	350	0.0094	3.29	350	0.0078	2.73	-0.56	-17.02%	3.90%	3.79%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	350	-0.0003	-0.11	350	0.0000	0.01	0.12	110.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**28.69**			**30.46**	**1.77**	**6.18%**	**43.49%**	**42.28%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.13%	1.10%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	2.19%	2.13%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.34%	2.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**31.01**			**32.78**	**1.77**	**5.72%**	**46.81%**	**45.51%**
Sub-Total: Distribution (based on TOU prices)			**31.11**			**32.89**	**1.77**	**5.70%**	**46.95%**	**45.65%**
Retail Transmission Rate – Network Service Rate	370	0.0067	2.48	370	0.0078	2.90	0.42	16.84%	4.13%	4.02%
Retail Transmission Rate – Line and Transformation Connection Service Rate	370	0.0047	1.74	370	0.0064	2.38	0.64	36.98%	3.40%	3.31%
Sub-Total: Retail Transmission			**4.22**			**5.28**	**1.06**	**25.14%**	**7.54%**	**7.33%**
Sub-Total: Delivery (based on two-tier RPP prices)			**35.23**			**38.06**	**2.83**	**8.04%**	**54.34%**	**52.83%**
Sub-Total: Delivery (based on TOU prices)			**35.33**			**38.16**	**2.83**	**8.02%**	**54.49%**	**52.97%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.90%	1.85%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.36%	0.35%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.42%**	**2.35%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**63.87**			**66.70**	**2.83**	**4.44%**	**95.24%**	
HST		0.13	8.30		0.13	8.67	0.37	4.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**72.17**			**75.38**	**3.20**	**4.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.11		-0.08	-5.34	-0.23	-4.44%	-7.62%	
Total Amount on Two-Tier RPP			**67.06**			**70.04**	**2.97**	**4.44%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**65.78**			**68.61**	**2.83**	**4.31%**		**95.24%**
HST		0.13	8.55		0.13	8.92	0.37	4.31%		12.38%
Total Electricity Charge on TOU (including HST)			**74.33**			**77.53**	**3.20**	**4.31%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.26		-0.08	-5.49	-0.23	-4.31%		-7.62%
Total Amount on TOU			**69.07**			**72.04**	**2.97**	**4.31%**		**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	792.75
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	39.08%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.42%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**50.50%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		26.43%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		10.10%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.87%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**52.13%**	**51.41%**
Service Charge	1	24.78	24.78	1	27.71	27.71	2.93	11.82%	23.44%	23.12%
Fixed Deferral/Variance Account Rider	1	0.72	0.72	1	0.01	0.01	-0.71	-99.03%	0.01%	0.01%
Distribution Volumetric Rate	750	0.0094	7.05	750	0.0078	5.85	-1.20	-17.02%	4.95%	4.88%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	-0.0003	-0.23	750	0.0000	0.02	0.25	110.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**32.33**			**33.59**	**1.26**	**3.91%**	**28.42%**	**28.02%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.67%	0.66%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.25%	3.21%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	2.97%	2.93%
Sub-Total: Distribution (based on two-tier RPP prices)			**36.96**			**38.23**	**1.26**	**3.42%**	**32.34%**	**31.89%**
Sub-Total: Distribution (based on TOU prices)			**36.63**			**37.89**	**1.26**	**3.45%**	**32.06%**	**31.61%**
Retail Transmission Rate – Network Service Rate	793	0.0067	5.31	793	0.0078	6.21	0.89	16.84%	5.25%	5.18%
Retail Transmission Rate – Line and Transformation Connection Service Rate	793	0.0047	3.73	793	0.0064	5.10	1.38	36.98%	4.32%	4.26%
Sub-Total: Retail Transmission			**9.04**			**11.31**	**2.27**	**25.14%**	**9.57%**	**9.43%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.00**			**49.54**	**3.54**	**7.69%**	**41.91%**	**41.32%**
Sub-Total: Delivery (based on TOU prices)			**45.66**			**49.20**	**3.54**	**7.74%**	**41.62%**	**41.05%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.41%	2.38%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.83%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**109.04**			**112.58**	**3.54**	**3.24%**	**95.24%**	
HST		0.13	14.18		0.13	14.64	0.46	3.24%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**123.22**			**127.21**	**4.00**	**3.24%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.72		-0.08	-9.01	-0.28	-3.24%	-7.62%	
Total Amount on Two-Tier RPP			**114.49**			**118.21**	**3.71**	**3.24%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**110.63**			**114.16**	**3.54**	**3.20%**		**95.24%**
HST		0.13	14.38		0.13	14.84	0.46	3.20%		12.38%
Total Electricity Charge on TOU (including HST)			**125.01**			**129.00**	**4.00**	**3.20%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.85		-0.08	-9.13	-0.28	-3.20%		-7.62%
Total Amount on TOU			**116.16**			**119.87**	**3.71**	**3.20%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	755
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	798
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.87%	
Energy Second Tier (kWh)	155	0.090	13.95	155	0.090	13.95	0.00	0.00%	11.74%	
Sub-Total: Energy (RPP)			**60.15**			**60.15**	**0.00**	**0.00%**	**50.61%**	
TOU-Off Peak	491	0.065	31.90	491	0.065	31.90	0.00	0.00%		26.48%
TOU-Mid Peak	128	0.095	12.19	128	0.095	12.19	0.00	0.00%		10.12%
TOU-On Peak	136	0.132	17.94	136	0.132	17.94	0.00	0.00%		14.89%
Sub-Total: Energy (TOU)			**62.03**			**62.03**	0.00	0.00%	**52.19%**	**51.49%**
Service Charge	1	24.78	24.78	1	27.71	27.71	2.93	11.82%	23.32%	23.00%
Fixed Deferral/Variance Account Rider	1	0.72	0.72	1	0.01	0.01	-0.71	-99.03%	0.01%	0.01%
Distribution Volumetric Rate	755	0.0094	7.10	755	0.0078	5.89	-1.21	-17.02%	4.96%	4.89%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	755	-0.0003	-0.23	755	0.0000	0.02	0.25	110.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**32.37**			**33.63**	**1.26**	**3.89%**	**28.30%**	**27.91%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.66%	0.66%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.87	43	0.0900	3.87	0.00	0.00%	3.26%	3.22%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	43	0.0822	3.54	0.00	0.00%	2.98%	2.93%
Sub-Total: Distribution (based on two-tier RPP prices)			**37.03**			**38.29**	**1.26**	**3.40%**	**32.22%**	**31.79%**
Sub-Total: Distribution (based on TOU prices)			**36.70**			**37.95**	**1.26**	**3.43%**	**31.94%**	**31.51%**
Retail Transmission Rate – Network Service Rate	798	0.0067	5.35	798	0.0078	6.25	0.90	16.84%	5.26%	5.19%
Retail Transmission Rate – Line and Transformation Connection Service Rate	798	0.0047	3.75	798	0.0064	5.14	1.39	36.98%	4.32%	4.26%
Sub-Total: Retail Transmission			**9.10**			**11.38**	**2.29**	**25.14%**	**9.58%**	**9.45%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.13**			**49.68**	**3.55**	**7.69%**	**41.80%**	**41.24%**
Sub-Total: Delivery (based on TOU prices)			**45.79**			**49.34**	**3.55**	**7.74%**	**41.51%**	**40.96%**
Wholesale Market Service Rate	798	0.0036	2.87	798	0.0036	2.87	0.00	0.00%	2.42%	2.38%
Rural Rate Protection Charge	798	0.0003	0.24	798	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	798	0.0000	0.00	798	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**3.36**			**3.36**	**0.00**	**0.00%**	**2.83%**	**2.79%**
Debt Retirement Charge (DRC)	755	0.000	**0.00**	755	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**109.64**			**113.19**	**3.55**	**3.23%**	**95.24%**	
HST		0.13	14.25		0.13	14.71	0.46	3.23%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**123.90**			**127.90**	**4.01**	**3.23%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.77		-0.08	-9.06	-0.28	-3.23%	-7.62%	
Total Amount on Two-Tier RPP			**115.13**			**118.85**	**3.72**	**3.23%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**111.19**			**114.73**	**3.55**	**3.19%**		**95.24%**
HST		0.13	14.45		0.13	14.92	0.46	3.19%		12.38%
Total Electricity Charge on TOU (including HST)			**125.64**			**129.65**	**4.01**	**3.19%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.89		-0.08	-9.18	-0.28	-3.19%		-7.62%
Total Amount on TOU			**116.75**			**120.47**	**3.72**	**3.19%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1479.8
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	22.92%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	35.72%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**58.64%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		29.94%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.44%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		16.83%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**57.06%**	**58.21%**
Service Charge	1	24.78	24.78	1	27.71	27.71	2.93	11.82%	13.75%	14.02%
Fixed Deferral/Variance Account Rider	1	0.72	0.72	1	0.01	0.01	-0.71	-99.03%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0094	13.16	1,400	0.0078	10.92	-2.24	-17.02%	5.42%	5.53%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,400	-0.0003	-0.42	1,400	0.0000	0.04	0.46	110.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**38.24**			**38.68**	**0.44**	**1.15%**	**19.19%**	**19.58%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.39%	0.40%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.56%	3.63%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.25%	3.32%
Sub-Total: Distribution (based on two-tier RPP prices)			**46.21**			**46.65**	**0.44**	**0.95%**	**23.14%**	**23.61%**
Sub-Total: Distribution (based on TOU prices)			**45.59**			**46.03**	**0.44**	**0.96%**	**22.83%**	**23.29%**
Retail Transmission Rate – Network Service Rate	1,480	0.0067	9.91	1,480	0.0078	11.58	1.67	16.84%	5.75%	5.86%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,480	0.0047	6.96	1,480	0.0064	9.53	2.57	36.98%	4.73%	4.82%
Sub-Total: Retail Transmission			**16.87**			**21.11**	**4.24**	**25.14%**	**10.47%**	**10.68%**
Sub-Total: Delivery (based on two-tier RPP prices)			**63.08**			**67.76**	**4.68**	**7.42%**	**33.61%**	**34.29%**
Sub-Total: Delivery (based on TOU prices)			**62.46**			**67.14**	**4.68**	**7.49%**	**33.30%**	**33.98%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.64%	2.70%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**2.99%**	**3.05%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**187.30**			**191.98**	**4.68**	**2.50%**	**95.24%**	
HST		0.13	24.35		0.13	24.96	0.61	2.50%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**211.65**			**216.94**	**5.29**	**2.50%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.98		-0.08	-15.36	-0.37	-2.50%	-7.62%	
Total Amount on Two-Tier RPP			**196.67**			**201.58**	**4.91**	**2.50%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**183.50**			**188.18**	**4.68**	**2.55%**		**95.24%**
HST		0.13	23.86		0.13	24.46	0.61	2.55%		12.38%
Total Electricity Charge on TOU (including HST)			**207.36**			**212.64**	**5.29**	**2.55%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.68		-0.08	-15.05	-0.37	-2.55%		-7.62%
Total Amount on TOU			**192.68**			**197.59**	**4.91**	**2.55%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	430
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	37.61%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**37.61%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		20.06%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.67%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		11.28%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**40.13%**	**39.02%**
Service Charge	1	33.77	33.77	1	37.79	36.43	2.66	7.88%	44.48%	43.25%
Fixed Deferral/Variance Account Rider	1	0.82	0.82	1	0.00	0.00	-0.82	-99.51%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0230	2.66	400	0.0218	0.00	-2.66	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	400	-0.0002	-0.08	400	0.0000	0.01	0.09	110.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.17**			**36.44**	**-0.73**	**-1.96%**	**44.50%**	**43.26%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.96%	0.94%
Line Losses on Cost of Power (based on two-tier RPP prices)	30	0.0770	2.34	30	0.0770	2.34	0.00	0.00%	2.86%	2.78%
Line Losses on Cost of Power (based on TOU prices)	30	0.0822	2.50	30	0.0822	2.50	0.00	0.00%	3.05%	2.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.30**			**39.57**	**-0.73**	**-1.81%**	**48.32%**	**46.98%**
Sub-Total: Distribution (based on TOU prices)			**40.46**			**39.73**	**-0.73**	**-1.80%**	**48.51%**	**47.17%**
Retail Transmission Rate – Network Service Rate	430	0.0064	2.75	430	0.0072	3.10	0.35	12.61%	3.79%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	430	0.0047	2.02	430	0.0060	2.60	0.57	28.34%	3.17%	3.08%
Sub-Total: Retail Transmission			**4.78**			**5.70**	**0.92**	**19.27%**	**6.96%**	**6.76%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.08**			**45.27**	**0.19**	**0.43%**	**55.28%**	**53.75%**
Sub-Total: Delivery (based on TOU prices)			**45.24**			**45.43**	**0.19**	**0.43%**	**55.47%**	**53.93%**
Wholesale Market Service Rate	430	0.0036	1.55	430	0.0036	1.55	0.00	0.00%	1.89%	1.84%
Rural Rate Protection Charge	430	0.0003	0.13	430	0.0003	0.13	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	430	0.0000	0.00	430	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%	0.30%
Sub-Total: Regulatory			**1.93**			**1.93**	**0.00**	**0.00%**	**2.35%**	**2.29%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**77.81**			**78.00**	**0.19**	**0.25%**	**95.24%**	
HST		0.13	10.11		0.13	10.14	0.03	0.25%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**87.92**			**88.14**	**0.22**	**0.25%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.22		-0.08	-6.24	-0.02	-0.25%	-7.62%	
Total Amount on Two-Tier RPP			**81.70**			**81.90**	**0.20**	**0.25%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**80.03**			**80.22**	**0.19**	**0.24%**		**95.24%**
HST		0.13	10.40		0.13	10.43	0.03	0.24%		12.38%
Total Electricity Charge on TOU (including HST)			**90.43**			**90.65**	**0.22**	**0.24%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.40		-0.08	-6.42	-0.02	-0.24%		-7.62%
Total Amount on TOU			**84.03**			**84.23**	**0.20**	**0.24%**		**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	807
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.88%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.07%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.95%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.66%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.81%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.43%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.53%**	**49.89%**
Service Charge	1	33.77	33.77	1	37.79	36.43	2.66	7.88%	29.87%	29.50%
Fixed Deferral/Variance Account Rider	1	0.82	0.82	1	0.00	0.00	-0.82	-99.51%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0230	2.66	750	0.0218	0.00	-2.66	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	-0.0002	-0.15	750	0.0000	0.02	0.17	110.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.10**			**36.45**	**-0.65**	**-1.75%**	**29.89%**	**29.51%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	4.21%	4.15%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	3.84%	3.79%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.02**			**42.37**	**-0.65**	**-1.51%**	**34.74%**	**34.31%**
Sub-Total: Distribution (based on TOU prices)			**42.57**			**41.92**	**-0.65**	**-1.53%**	**34.37%**	**33.94%**
Retail Transmission Rate – Network Service Rate	807	0.0064	5.16	807	0.0072	5.82	0.65	12.61%	4.77%	4.71%
Retail Transmission Rate – Line and Transformation Connection Service Rate	807	0.0047	3.79	807	0.0060	4.87	1.07	28.34%	3.99%	3.94%
Sub-Total: Retail Transmission			**8.96**			**10.68**	**1.73**	**19.27%**	**8.76%**	**8.65%**
Sub-Total: Delivery (based on two-tier RPP prices)			**51.98**			**53.05**	**1.08**	**2.07%**	**43.50%**	**42.96%**
Sub-Total: Delivery (based on TOU prices)			**51.53**			**52.61**	**1.08**	**2.09%**	**43.13%**	**42.59%**
Wholesale Market Service Rate	807	0.0036	2.91	807	0.0036	2.91	0.00	0.00%	2.38%	2.35%
Rural Rate Protection Charge	807	0.0003	0.24	807	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	807	0.0000	0.00	807	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.40**			**3.40**	**0.00**	**0.00%**	**2.79%**	**2.75%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**115.08**			**116.15**	**1.08**	**0.93%**	**95.24%**	
HST		0.13	14.96		0.13	15.10	0.14	0.93%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**130.03**			**131.25**	**1.21**	**0.93%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.21		-0.08	-9.29	-0.09	-0.93%	-7.62%	
Total Amount on Two-Tier RPP			**120.83**			**121.96**	**1.13**	**0.93%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**116.55**			**117.62**	**1.08**	**0.92%**		**95.24%**
HST		0.13	15.15		0.13	15.29	0.14	0.92%		12.38%
Total Electricity Charge on TOU (including HST)			**131.70**			**132.91**	**1.21**	**0.92%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.32		-0.08	-9.41	-0.09	-0.92%		-7.62%
Total Amount on TOU			**122.38**			**123.50**	**1.13**	**0.92%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	920
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	990
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	32.41%	
Energy Second Tier (kWh)	320	0.090	28.80	320	0.090	28.80	0.00	0.00%	20.20%	
Sub-Total: Energy (RPP)			**75.00**			**75.00**	**0.00**	**0.00%**	**52.62%**	
TOU-Off Peak	598	0.065	38.87	598	0.065	38.87	0.00	0.00%		27.26%
TOU-Mid Peak	156	0.095	14.86	156	0.095	14.86	0.00	0.00%		10.42%
TOU-On Peak	166	0.132	21.86	166	0.132	21.86	0.00	0.00%		15.33%
Sub-Total: Energy (TOU)			**75.59**			**75.59**	0.00	0.00%	**53.03%**	**53.01%**
Service Charge	1	33.77	33.77	1	37.79	36.43	2.66	7.88%	25.56%	25.55%
Fixed Deferral/Variance Account Rider	1	0.82	0.82	1	0.00	0.00	-0.82	-99.51%	0.00%	0.00%
Distribution Volumetric Rate	920	0.0230	2.66	920	0.0218	0.00	-2.66	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	920	-0.0002	-0.18	920	0.0000	0.02	0.20	110.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.07**			**36.45**	**-0.61**	**-1.66%**	**25.57%**	**25.57%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.55%	0.55%
Line Losses on Cost of Power (based on two-tier RPP prices)	70	0.0900	6.29	70	0.0900	6.29	0.00	0.00%	4.41%	4.41%
Line Losses on Cost of Power (based on TOU prices)	70	0.0822	5.74	70	0.0822	5.74	0.00	0.00%	4.03%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.15**			**43.54**	**-0.61**	**-1.39%**	**30.54%**	**30.53%**
Sub-Total: Distribution (based on TOU prices)			**43.60**			**42.99**	**-0.61**	**-1.41%**	**30.16%**	**30.15%**
Retail Transmission Rate – Network Service Rate	990	0.0064	6.34	990	0.0072	7.13	0.80	12.61%	5.01%	5.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	990	0.0047	4.65	990	0.0060	5.97	1.32	28.34%	4.19%	4.19%
Sub-Total: Retail Transmission			**10.99**			**13.11**	**2.12**	**19.27%**	**9.19%**	**9.19%**
Sub-Total: Delivery (based on two-tier RPP prices)			**55.14**			**56.64**	**1.50**	**2.73%**	**39.74%**	**39.73%**
Sub-Total: Delivery (based on TOU prices)			**54.59**			**56.09**	**1.50**	**2.75%**	**39.35%**	**39.34%**
Wholesale Market Service Rate	990	0.0036	3.56	990	0.0036	3.56	0.00	0.00%	2.50%	2.50%
Rural Rate Protection Charge	990	0.0003	0.30	990	0.0003	0.30	0.00	0.00%	0.21%	0.21%
Ontario Electricity Support Program Charge	990	0.0000	0.00	990	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**4.11**			**4.11**	**0.00**	**0.00%**	**2.88%**	**2.88%**
Debt Retirement Charge (DRC)	920	0.000	**0.00**	920	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricity Charge on Two-Tier RPP			**134.25**			**135.75**	**1.50**	**1.12%**	**95.24%**	
HST		0.13	17.45		0.13	17.65	0.20	1.12%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**151.70**			**153.40**	**1.70**	**1.12%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.74		-0.08	-10.86	-0.12	-1.12%	-7.62%	
Total Amount on Two-Tier RPP			**140.96**			**142.54**	**1.58**	**1.12%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**134.29**			**135.79**	**1.50**	**1.12%**		**95.24%**
HST		0.13	17.46		0.13	17.65	0.20	1.12%		12.38%
Total Electricity Charge on TOU (including HST)			**151.74**			**153.44**	**1.70**	**1.12%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.74		-0.08	-10.86	-0.12	-1.12%		-7.62%
Total Amount on TOU			**141.00**			**142.58**	**1.58**	**1.12%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1937
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.55%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.36%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.91%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.51%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		12.05%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.72%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	**0.00**	**0.00%**	**59.37%**	**61.28%**
Service Charge	1	33.77	33.77	1	37.79	36.43	2.66	7.88%	14.63%	15.10%
Fixed Deferral/Variance Account Rider	1	0.82	0.82	1	0.00	0.00	-0.82	-99.51%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0230	2.66	1,800	0.0218	0.00	-2.66	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,800	-0.0002	-0.36	1,800	0.0000	0.04	0.40	110.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.89**			**36.47**	**-0.42**	**-1.14%**	**14.64%**	**15.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.32%	0.33%
Line Losses on Cost of Power (based on two-tier RPP prices)	137	0.0900	12.31	137	0.0900	12.31	0.00	0.00%	4.94%	5.10%
Line Losses on Cost of Power (based on TOU prices)	137	0.0822	11.24	137	0.0822	11.24	0.00	0.00%	4.51%	4.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.99**			**49.57**	**-0.42**	**-0.84%**	**19.90%**	**20.54%**
Sub-Total: Distribution (based on TOU prices)			**48.92**			**48.50**	**-0.42**	**-0.86%**	**19.47%**	**20.10%**
Retail Transmission Rate – Network Service Rate	1,937	0.0064	12.40	1,937	0.0072	13.96	1.56	12.61%	5.60%	5.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,937	0.0047	9.10	1,937	0.0060	11.68	2.58	28.34%	4.69%	4.84%
Sub-Total: Retail Transmission			**21.50**			**25.64**	**4.14**	**19.27%**	**10.29%**	**10.63%**
Sub-Total: Delivery (based on two-tier RPP prices)			**71.49**			**75.21**	**3.72**	**5.21%**	**30.20%**	**31.17%**
Sub-Total: Delivery (based on TOU prices)			**70.42**			**74.14**	**3.72**	**5.29%**	**29.77%**	**30.72%**
Wholesale Market Service Rate	1,937	0.0036	6.97	1,937	0.0036	6.97	0.00	0.00%	2.80%	2.89%
Rural Rate Protection Charge	1,937	0.0003	0.58	1,937	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,937	0.0000	0.00	1,937	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.80**			**7.80**	**0.00**	**0.00%**	**3.13%**	**3.23%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**233.49**			**237.22**	**3.72**	**1.59%**	**95.24%**	
HST		0.13	30.35		0.13	30.84	0.48	1.59%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**263.85**			**268.06**	**4.21**	**1.59%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.68		-0.08	-18.98	-0.30	-1.59%	-7.62%	
Total Amount on Two-Tier RPP			**245.17**			**249.08**	**3.91**	**1.59%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**226.11**			**229.83**	**3.72**	**1.65%**		**95.24%**
HST		0.13	29.39		0.13	29.88	0.48	1.65%		12.38%
Total Electricity Charge on TOU (including HST)			**255.50**			**259.71**	**4.21**	**1.65%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.09		-0.08	-18.39	-0.30	-1.65%		-7.62%
Total Amount on TOU			**237.41**			**241.32**	**3.91**	**1.65%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	450
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	497.25
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	450	0.077	34.65	450	0.077	34.65	0.00	0.00%	39.36%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**34.65**			**34.65**	**0.00**	**0.00%**	**39.36%**	
TOU-Off Peak	293	0.065	19.01	293	0.065	19.01	0.00	0.00%		20.96%
TOU-Mid Peak	77	0.095	7.27	77	0.095	7.27	0.00	0.00%		8.01%
TOU-On Peak	81	0.132	10.69	81	0.132	10.69	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**36.97**			**36.97**	0.00	0.00%	**42.00%**	**40.75%**
Service Charge (RRRP credit applied)	1	19.83	19.83	1	25.02	25.02	5.19	26.17%	28.42%	27.58%
Fixed Deferral/Variance Account Rider	1	1.36	1.36	1	-0.02	-0.02	-1.38	-101.54%	-0.02%	-0.02%
Distribution Volumetric Rate	450	0.0374	16.60	450	0.0359	11.41	-5.19	-31.26%	12.96%	12.58%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	450	0.0000	0.00	450	0.0000	0.00	0.00	N/A	0.01%	0.00%
Sub-Total: Distribution (excluding pass through)			**37.79**			**36.41**	**-1.38**	**-3.64%**	**41.37%**	**40.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.90%	0.87%
Line Losses on Cost of Power (based on two-tier RPP prices)	47	0.0770	3.64	47	0.0770	3.64	0.00	0.00%	4.13%	4.01%
Line Losses on Cost of Power (based on TOU prices)	47	0.0822	3.88	47	0.0822	3.88	0.00	0.00%	4.41%	4.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.22**			**40.84**	**-1.38**	**-3.26%**	**46.40%**	**45.02%**
Sub-Total: Distribution (based on TOU prices)			**42.46**			**41.09**	**-1.38**	**-3.24%**	**46.68%**	**45.29%**
Retail Transmission Rate – Network Service Rate	497	0.0062	3.08	497	0.0067	3.35	0.27	8.71%	3.81%	3.69%
Retail Transmission Rate – Line and Transformation Connection Service Rate	497	0.0044	2.19	497	0.0056	2.80	0.61	27.95%	3.18%	3.09%
Sub-Total: Retail Transmission			**5.27**			**6.15**	**0.88**	**16.70%**	**6.99%**	**6.78%**
Sub-Total: Delivery (based on two-tier RPP prices)			**47.49**			**46.99**	**-0.50**	**-1.05%**	**53.39%**	**51.80%**
Sub-Total: Delivery (based on TOU prices)			**47.73**			**47.24**	**-0.50**	**-1.04%**	**53.66%**	**52.07%**
Wholesale Market Service Rate	497	0.0036	1.79	497	0.0036	1.79	0.00	0.00%	2.03%	1.97%
Rural Rate Protection Charge	497	0.0003	0.15	497	0.0003	0.15	0.00	0.00%	0.17%	0.16%
Ontario Electricity Support Program Charge	497	0.0000	0.00	497	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%	0.28%
Sub-Total: Regulatory			**2.19**			**2.19**	**0.00**	**0.00%**	**2.49%**	**2.41%**
Debt Retirement Charge (DRC)	450	0.000	**0.00**	450	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**84.33**			**83.83**	**-0.50**	**-0.59%**	**95.24%**	
HST		0.13	10.96		0.13	10.90	-0.06	-0.59%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**95.29**			**94.73**	**-0.56**	**-0.59%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.75		-0.08	-6.71	0.04	0.59%	-7.62%	
Total Amount on Two-Tier RPP			**88.54**			**88.02**	**-0.52**	**-0.59%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**86.89**			**86.40**	**-0.50**	**-0.57%**		**95.24%**
HST		0.13	11.30		0.13	11.23	-0.06	-0.57%		12.38%
Total Electricity Charge on TOU (including HST)			**98.19**			**97.63**	**-0.56**	**-0.57%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.95		-0.08	-6.91	0.04	0.57%		-7.62%
Total Amount on TOU			**91.24**			**90.72**	**-0.52**	**-0.57%**		**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	828.75
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.37%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.92%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.30%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.35%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.69%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.26%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.85%**	**49.30%**
Service Charge (RRRP credit applied)	1	19.83	19.83	1	25.02	25.02	5.19	26.17%	20.24%	20.02%
Fixed Deferral/Variance Account Rider	1	1.36	1.36	1	-0.02	-0.02	-1.38	-101.54%	-0.02%	-0.02%
Distribution Volumetric Rate	750	0.0374	16.60	750	0.0359	11.41	-5.19	-31.26%	9.23%	9.13%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.00	750	0.0000	0.01	0.01	N/A	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.79**			**36.42**	**-1.37**	**-3.63%**	**29.46%**	**29.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.63%
Line Losses on Cost of Power (based on two-tier RPP prices)	79	0.0900	7.09	79	0.0900	7.09	0.00	0.00%	5.73%	5.67%
Line Losses on Cost of Power (based on TOU prices)	79	0.0822	6.47	79	0.0822	6.47	0.00	0.00%	5.23%	5.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**45.67**			**44.29**	**-1.37**	**-3.01%**	**35.83%**	**35.44%**
Sub-Total: Distribution (based on TOU prices)			**45.05**			**43.68**	**-1.37**	**-3.05%**	**35.33%**	**34.95%**
Retail Transmission Rate – Network Service Rate	829	0.0062	5.14	829	0.0067	5.59	0.45	8.71%	4.52%	4.47%
Retail Transmission Rate – Line and Transformation Connection Service Rate	829	0.0044	3.65	829	0.0056	4.67	1.02	27.95%	3.77%	3.73%
Sub-Total: Retail Transmission			**8.78**			**10.25**	**1.47**	**16.70%**	**8.29%**	**8.20%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.45**			**54.55**	**0.09**	**0.17%**	**44.13%**	**43.64%**
Sub-Total: Delivery (based on TOU prices)			**53.83**			**53.93**	**0.09**	**0.17%**	**43.63%**	**43.15%**
Wholesale Market Service Rate	829	0.0036	2.98	829	0.0036	2.98	0.00	0.00%	2.41%	2.39%
Rural Rate Protection Charge	829	0.0003	0.25	829	0.0003	0.25	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	829	0.0000	0.00	829	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.48**			**3.48**	**0.00**	**0.00%**	**2.82%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**117.63**			**117.73**	**0.09**	**0.08%**	**95.24%**	
HST		0.13	15.29		0.13	15.30	0.01	0.08%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**132.93**			**133.03**	**0.11**	**0.08%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.42	-0.01	-0.08%	-7.62%	
Total Amount on Two-Tier RPP			**123.52**			**123.61**	**0.10**	**0.08%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**118.94**			**119.03**	**0.09**	**0.08%**		**95.24%**
HST		0.13	15.46		0.13	15.47	0.01	0.08%		12.38%
Total Electricity Charge on TOU (including HST)			**134.40**			**134.50**	**0.11**	**0.08%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.51		-0.08	-9.52	-0.01	-0.08%		-7.62%
Total Amount on TOU			**124.88**			**124.98**	**0.10**	**0.08%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	1152
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1272.96
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	26.68%	
Energy Second Tier (kWh)	552	0.090	49.68	552	0.090	49.68	0.00	0.00%	28.69%	
Sub-Total: Energy (RPP)			**95.88**			**95.88**	**0.00**	**0.00%**	**55.36%**	
TOU-Off Peak	749	0.065	48.67	749	0.065	48.67	0.00	0.00%		28.48%
TOU-Mid Peak	196	0.095	18.60	196	0.095	18.60	0.00	0.00%		10.89%
TOU-On Peak	207	0.132	27.37	207	0.132	27.37	0.00	0.00%		16.02%
Sub-Total: Energy (TOU)			**94.65**			**94.65**	0.00	0.00%	**54.65%**	**55.38%**
Service Charge (RRRP credit applied)	1	19.83	19.83	1	25.02	25.02	5.19	26.17%	14.45%	14.64%
Fixed Deferral/Variance Account Rider	1	1.36	1.36	1	-0.02	-0.02	-1.38	-101.54%	-0.01%	-0.01%
Distribution Volumetric Rate	1,152	0.0374	16.60	1,152	0.0359	11.41	-5.19	-31.26%	6.59%	6.68%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,152	0.0000	0.00	1,152	0.0000	0.01	0.01	N/A	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.79**			**36.42**	**-1.37**	**-3.62%**	**21.03%**	**21.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	121	0.0900	10.89	121	0.0900	10.89	0.00	0.00%	6.29%	6.37%
Line Losses on Cost of Power (based on TOU prices)	121	0.0822	9.94	121	0.0822	9.94	0.00	0.00%	5.74%	5.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.47**			**48.10**	**-1.37**	**-2.77%**	**27.77%**	**28.14%**
Sub-Total: Distribution (based on TOU prices)			**48.52**			**47.15**	**-1.37**	**-2.82%**	**27.22%**	**27.59%**
Retail Transmission Rate – Network Service Rate	1,273	0.0062	7.89	1,273	0.0067	8.58	0.69	8.71%	4.95%	5.02%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,273	0.0044	5.60	1,273	0.0056	7.17	1.57	27.95%	4.14%	4.19%
Sub-Total: Retail Transmission			**13.49**			**15.75**	**2.25**	**16.70%**	**9.09%**	**9.21%**
Sub-Total: Delivery (based on two-tier RPP prices)			**62.96**			**63.84**	**0.88**	**1.40%**	**36.86%**	**37.36%**
Sub-Total: Delivery (based on TOU prices)			**62.01**			**62.90**	**0.88**	**1.42%**	**36.32%**	**36.80%**
Wholesale Market Service Rate	1,273	0.0036	4.58	1,273	0.0036	4.58	0.00	0.00%	2.65%	2.68%
Rural Rate Protection Charge	1,273	0.0003	0.38	1,273	0.0003	0.38	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,273	0.0000	0.00	1,273	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.15%
Sub-Total: Regulatory			**5.21**			**5.21**	**0.00**	**0.00%**	**3.01%**	**3.05%**
Debt Retirement Charge (DRC)	1,152	0.000	**0.00**	1,152	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**164.05**			**164.94**	**0.88**	**0.54%**	**95.24%**	
HST		0.13	21.33		0.13	21.44	0.11	0.54%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**185.38**			**186.38**	**1.00**	**0.54%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.12		-0.08	-13.20	-0.07	-0.54%	-7.62%	
Total Amount on Two-Tier RPP			**172.26**			**173.18**	**0.93**	**0.54%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**161.87**			**162.76**	**0.88**	**0.55%**		**95.24%**
HST		0.13	21.04		0.13	21.16	0.11	0.55%		12.38%
Total Electricity Charge on TOU (including HST)			**182.92**			**183.92**	**1.00**	**0.55%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.95		-0.08	-13.02	-0.07	-0.55%		-7.62%
Total Amount on TOU			**169.97**			**170.90**	**0.93**	**0.55%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	2300
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	2541.5
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	14.68%	
Energy Second Tier (kWh)	1,700	0.090	153.00	1,700	0.090	153.00	0.00	0.00%	48.61%	
Sub-Total: Energy (RPP)			**199.20**			**199.20**	**0.00**	**0.00%**	**63.29%**	
TOU-Off Peak	1,495	0.065	97.18	1,495	0.065	97.18	0.00	0.00%		32.18%
TOU-Mid Peak	391	0.095	37.15	391	0.095	37.15	0.00	0.00%		12.30%
TOU-On Peak	414	0.132	54.65	414	0.132	54.65	0.00	0.00%		18.09%
Sub-Total: Energy (TOU)			**188.97**			**188.97**	0.00	0.00%	**60.04%**	**62.57%**
Service Charge (RRRP credit applied)	1	19.83	19.83	1	25.02	25.02	5.19	26.17%	7.95%	8.28%
Fixed Deferral/Variance Account Rider	1	1.36	1.36	1	-0.02	-0.02	-1.38	-101.54%	-0.01%	-0.01%
Distribution Volumetric Rate	2,300	0.0374	16.60	2,300	0.0359	11.41	-5.19	-31.26%	3.63%	3.78%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,300	0.0000	0.00	2,300	0.0000	0.02	0.02	N/A	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**37.79**			**36.43**	**-1.36**	**-3.59%**	**11.58%**	**12.06%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.26%
Line Losses on Cost of Power (based on two-tier RPP prices)	242	0.0900	21.74	242	0.0900	21.74	0.00	0.00%	6.91%	7.20%
Line Losses on Cost of Power (based on TOU prices)	242	0.0822	19.84	242	0.0822	19.84	0.00	0.00%	6.30%	6.57%
Sub-Total: Distribution (based on two-tier RPP prices)			**60.32**			**58.96**	**-1.36**	**-2.25%**	**18.73%**	**19.52%**
Sub-Total: Distribution (based on TOU prices)			**58.42**			**57.06**	**-1.36**	**-2.32%**	**18.13%**	**18.89%**
Retail Transmission Rate – Network Service Rate	2,542	0.0062	15.76	2,542	0.0067	17.13	1.37	8.71%	5.44%	5.67%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,542	0.0044	11.18	2,542	0.0056	14.31	3.13	27.95%	4.55%	4.74%
Sub-Total: Retail Transmission			**26.94**			**31.44**	**4.50**	**16.70%**	**9.99%**	**10.41%**
Sub-Total: Delivery (based on two-tier RPP prices)			**87.25**			**90.40**	**3.14**	**3.60%**	**28.72%**	**29.93%**
Sub-Total: Delivery (based on TOU prices)			**85.36**			**88.50**	**3.14**	**3.68%**	**28.12%**	**29.30%**
Wholesale Market Service Rate	2,542	0.0036	9.15	2,542	0.0036	9.15	0.00	0.00%	2.91%	3.03%
Rural Rate Protection Charge	2,542	0.0003	0.76	2,542	0.0003	0.76	0.00	0.00%	0.24%	0.25%
Ontario Electricity Support Program Charge	2,542	0.0000	0.00	2,542	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**10.16**			**10.16**	**0.00**	**0.00%**	**3.23%**	**3.36%**
Debt Retirement Charge (DRC)	2,300	0.000	**0.00**	2,300	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**296.62**			**299.76**	**3.14**	**1.06%**	**95.24%**	
HST		0.13	38.56		0.13	38.97	0.41	1.06%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**335.18**			**338.73**	**3.55**	**1.06%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.73		-0.08	-23.98	-0.25	-1.06%	-7.62%	
Total Amount on Two-Tier RPP			**311.45**			**314.75**	**3.30**	**1.06%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**284.49**			**287.63**	**3.14**	**1.10%**		**95.24%**
HST		0.13	36.98		0.13	37.39	0.41	1.10%		12.38%
Total Electricity Charge on TOU (including HST)			**321.48**			**325.02**	**3.55**	**1.10%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-22.76		-0.08	-23.01	-0.25	-1.10%		-7.62%
Total Amount on TOU			**298.72**			**302.01**	**3.30**	**1.10%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	50
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	55
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	50	0.077	3.85	50	0.077	3.85	0.00	0.00%	7.39%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**3.85**			**3.85**	**0.00**	**0.00%**	**7.39%**	
TOU-Off Peak	33	0.065	2.11	33	0.065	2.11	0.00	0.00%		4.03%
TOU-Mid Peak	9	0.095	0.81	9	0.095	0.81	0.00	0.00%		1.54%
TOU-On Peak	9	0.132	1.19	9	0.132	1.19	0.00	0.00%		2.27%
Sub-Total: Energy (TOU)			**4.11**			**4.11**	0.00	0.00%	**7.89%**	**7.84%**
Service Charge	1	36.28	36.28	1	40.52	40.52	4.24	11.69%	77.79%	77.35%
Fixed Deferral/Variance Account Rider	1	0.84	0.84	1	0.00	0.00	-0.84	-100.24%	0.00%	0.00%
Distribution Volumetric Rate	50	0.0635	3.18	50	0.0601	3.01	-0.17	-5.35%	5.77%	5.74%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	50	0.0003	0.02	50	0.0000	0.00	-0.01	-96.67%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.31**			**43.52**	**3.21**	**7.97%**	**83.56%**	**83.08%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.52%	1.51%
Line Losses on Cost of Power (based on two-tier RPP prices)	5	0.0770	0.40	5	0.0770	0.40	0.00	0.00%	0.77%	0.76%
Line Losses on Cost of Power (based on TOU prices)	5	0.0822	0.43	5	0.0822	0.43	0.00	0.00%	0.82%	0.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**41.50**			**44.71**	**3.21**	**7.74%**	**85.84%**	**85.35%**
Sub-Total: Distribution (based on TOU prices)			**41.53**			**44.74**	**3.21**	**7.74%**	**85.89%**	**85.40%**
Retail Transmission Rate – Network Service Rate	55	0.0051	0.28	55	0.0057	0.31	0.03	10.90%	0.60%	0.60%
Retail Transmission Rate – Line and Transformation Connection Service Rate	55	0.0042	0.23	55	0.0048	0.27	0.03	14.79%	0.51%	0.51%
Sub-Total: Retail Transmission			**0.51**			**0.58**	**0.06**	**12.66%**	**1.11%**	**1.10%**
Sub-Total: Delivery (based on two-tier RPP prices)			**42.01**			**45.29**	**3.28**	**7.80%**	**86.95%**	**86.46%**
Sub-Total: Delivery (based on TOU prices)			**42.04**			**45.32**	**3.28**	**7.80%**	**87.00%**	**86.51%**
Wholesale Market Service Rate	55	0.0036	0.20	55	0.0036	0.20	0.00	0.00%	0.38%	0.38%
Rural Rate Protection Charge	55	0.0003	0.02	55	0.0003	0.02	0.00	0.00%	0.03%	0.03%
Ontario Electricity Support Program Charge	55	0.0000	0.00	55	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.48%	0.48%
Sub-Total: Regulatory			**0.47**			**0.47**	**0.00**	**0.00%**	**0.89%**	**0.89%**
Debt Retirement Charge (DRC)	50	0.000	**0.00**	50	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**46.33**			**49.61**	**3.28**	**7.08%**	**95.24%**	
HST		0.13	6.02		0.13	6.45	0.43	7.08%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**52.35**			**56.06**	**3.70**	**7.08%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.71		-0.08	-3.97	-0.26	-7.08%	-7.62%	
Total Amount on Two-Tier RPP			**48.65**			**52.09**	**3.44**	**7.08%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**46.61**			**49.89**	**3.28**	**7.03%**		**95.24%**
HST		0.13	6.06		0.13	6.49	0.43	7.03%		12.38%
Total Electricity Charge on TOU (including HST)			**52.67**			**56.38**	**3.70**	**7.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.73		-0.08	-3.99	-0.26	-7.03%		-7.62%
Total Amount on TOU			**48.94**			**52.39**	**3.44**	**7.03%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	352
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	389
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	352	0.077	27.10	352	0.077	27.10	0.00	0.00%	26.28%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**27.10**			**27.10**	**0.00**	**0.00%**	**26.28%**	
TOU-Off Peak	229	0.065	14.87	229	0.065	14.87	0.00	0.00%		14.13%
TOU-Mid Peak	60	0.095	5.68	60	0.095	5.68	0.00	0.00%		5.40%
TOU-On Peak	63	0.132	8.36	63	0.132	8.36	0.00	0.00%		7.95%
Sub-Total: Energy (TOU)			**28.92**			**28.92**	0.00	0.00%	**28.04%**	**27.48%**
Service Charge	1	36.28	36.28	1	40.52	40.52	4.24	11.69%	39.29%	38.50%
Fixed Deferral/Variance Account Rider	1	0.84	0.84	1	0.00	0.00	-0.84	-100.24%	0.00%	0.00%
Distribution Volumetric Rate	352	0.0635	22.35	352	0.0601	21.16	-1.20	-5.35%	20.51%	20.10%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	352	0.0003	0.11	352	0.0000	0.00	-0.10	-96.67%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**59.58**			**61.68**	**2.10**	**3.52%**	**59.80%**	**58.60%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.77%	0.75%
Line Losses on Cost of Power (based on two-tier RPP prices)	37	0.0770	2.82	37	0.0770	2.82	0.00	0.00%	2.73%	2.68%
Line Losses on Cost of Power (based on TOU prices)	37	0.0822	3.01	37	0.0822	3.01	0.00	0.00%	2.92%	2.86%
Sub-Total: Distribution (based on two-tier RPP prices)			**63.19**			**65.29**	**2.10**	**3.32%**	**63.30%**	**62.03%**
Sub-Total: Distribution (based on TOU prices)			**63.38**			**65.47**	**2.10**	**3.31%**	**63.48%**	**62.21%**
Retail Transmission Rate – Network Service Rate	389	0.0051	1.98	389	0.0057	2.20	0.22	10.90%	2.13%	2.09%
Retail Transmission Rate – Line and Transformation Connection Service Rate	389	0.0042	1.63	389	0.0048	1.87	0.24	14.79%	1.82%	1.78%
Sub-Total: Retail Transmission			**3.61**			**4.07**	**0.46**	**12.66%**	**3.95%**	**3.87%**
Sub-Total: Delivery (based on two-tier RPP prices)			**66.80**			**69.36**	**2.56**	**3.83%**	**67.25%**	**65.90%**
Sub-Total: Delivery (based on TOU prices)			**66.99**			**69.55**	**2.56**	**3.82%**	**67.43%**	**66.08%**
Wholesale Market Service Rate	389	0.0036	1.40	389	0.0036	1.40	0.00	0.00%	1.36%	1.33%
Rural Rate Protection Charge	389	0.0003	0.12	389	0.0003	0.12	0.00	0.00%	0.11%	0.11%
Ontario Electricity Support Program Charge	389	0.0000	0.00	389	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.24%	0.24%
Sub-Total: Regulatory			**1.77**			**1.77**	**0.00**	**0.00%**	**1.71%**	**1.68%**
Debt Retirement Charge (DRC)	352	0.000	**0.00**	352	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**95.67**			**98.23**	**2.56**	**2.67%**	**95.24%**	
HST		0.13	12.44		0.13	12.77	0.33	2.67%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**108.11**			**111.00**	**2.89**	**2.67%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.65		-0.08	-7.86	-0.20	-2.67%	-7.62%	
Total Amount on Two-Tier RPP			**100.45**			**103.14**	**2.68**	**2.67%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**97.68**			**100.23**	**2.56**	**2.62%**		**95.24%**
HST		0.13	12.70		0.13	13.03	0.33	2.62%		12.38%
Total Electricity Charge on TOU (including HST)			**110.37**			**113.26**	**2.89**	**2.62%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.81		-0.08	-8.02	-0.20	-2.62%		-7.62%
Total Amount on TOU			**102.56**			**105.24**	**2.68**	**2.62%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1104
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	21.04%	
Energy Second Tier (kWh)	400	0.090	36.00	400	0.090	36.00	0.00	0.00%	16.40%	
Sub-Total: Energy (RPP)			**82.20**			**82.20**	**0.00**	**0.00%**	**37.44%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.32%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.39%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		10.87%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**37.42%**	**37.57%**
Service Charge	1	36.28	36.28	1	40.52	40.52	4.24	11.69%	18.46%	18.53%
Fixed Deferral/Variance Account Rider	1	0.84	0.84	1	0.00	0.00	-0.84	-100.24%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0635	63.50	1,000	0.0601	60.10	-3.40	-5.35%	27.37%	27.49%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0003	0.30	1,000	0.0000	0.01	-0.29	-96.67%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**100.92**			**100.63**	**-0.29**	**-0.29%**	**45.83%**	**46.02%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.36%	0.36%
Line Losses on Cost of Power (based on two-tier RPP prices)	104	0.0900	9.36	104	0.0900	9.36	0.00	0.00%	4.26%	4.28%
Line Losses on Cost of Power (based on TOU prices)	104	0.0822	8.54	104	0.0822	8.54	0.00	0.00%	3.89%	3.91%
Sub-Total: Distribution (based on two-tier RPP prices)			**111.07**			**110.78**	**-0.29**	**-0.26%**	**50.46%**	**50.66%**
Sub-Total: Distribution (based on TOU prices)			**110.25**			**109.96**	**-0.29**	**-0.26%**	**50.08%**	**50.29%**
Retail Transmission Rate – Network Service Rate	1,104	0.0051	5.63	1,104	0.0057	6.24	0.61	10.90%	2.84%	2.86%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,104	0.0042	4.64	1,104	0.0048	5.32	0.69	14.79%	2.42%	2.43%
Sub-Total: Retail Transmission			**10.27**			**11.57**	**1.30**	**12.66%**	**5.27%**	**5.29%**
Sub-Total: Delivery (based on two-tier RPP prices)			**121.34**			**122.34**	**1.01**	**0.83%**	**55.72%**	**55.95%**
Sub-Total: Delivery (based on TOU prices)			**120.52**			**121.53**	**1.01**	**0.84%**	**55.35%**	**55.58%**
Wholesale Market Service Rate	1,104	0.0036	3.97	1,104	0.0036	3.97	0.00	0.00%	1.81%	1.82%
Rural Rate Protection Charge	1,104	0.0003	0.33	1,104	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,104	0.0000	0.00	1,104	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.11%	0.11%
Sub-Total: Regulatory			**4.56**			**4.56**	**0.00**	**0.00%**	**2.07%**	**2.08%**
Debt Retirement Charge (DRC)	1,000	0.000	**0.00**	1,000	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**208.09**			**209.10**	**1.01**	**0.48%**	**95.24%**	
HST		0.13	27.05		0.13	27.18	0.13	0.48%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**235.14**			**236.28**	**1.14**	**0.48%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.65		-0.08	-16.73	-0.08	-0.48%	-7.62%	
Total Amount on Two-Tier RPP			**218.50**			**219.56**	**1.06**	**0.48%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**207.24**			**208.24**	**1.01**	**0.49%**		**95.24%**
HST		0.13	26.94		0.13	27.07	0.13	0.49%		12.38%
Total Electricity Charge on TOU (including HST)			**234.18**			**235.32**	**1.14**	**0.49%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.58		-0.08	-16.66	-0.08	-0.49%		-7.62%
Total Amount on TOU			**217.60**			**218.66**	**1.06**	**0.49%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1067
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	34.02%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	13.25%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**47.27%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		24.68%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.43%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.88%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**48.40%**	**47.99%**
Service Charge	1	23.3	23.30	1	23.88	23.88	0.58	2.49%	14.07%	13.95%
Fixed Deferral/Variance Account Rider	1	0.67	0.67	1	0.01	0.01	-0.66	-98.81%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0262	26.20	1,000	0.0278	27.80	1.60	6.11%	16.38%	16.24%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	-0.0001	-0.10	1,000	0.0000	0.03	0.13	130.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**50.07**			**51.72**	**1.65**	**3.29%**	**30.47%**	**30.21%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.47%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.03	67	0.0900	6.03	0.00	0.00%	3.55%	3.52%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.50	67	0.0822	5.50	0.00	0.00%	3.24%	3.22%
Sub-Total: Distribution (based on two-tier RPP prices)			**56.89**			**58.54**	**1.65**	**2.90%**	**34.48%**	**34.19%**
Sub-Total: Distribution (based on TOU prices)			**56.36**			**58.01**	**1.65**	**2.92%**	**34.17%**	**33.88%**
Retail Transmission Rate – Network Service Rate	1,067	0.0064	6.83	1,067	0.0061	6.52	-0.31	-4.59%	3.84%	3.81%
Retail Transmission Rate – Line and Transformation Connection S	1,067	0.0040	4.27	1,067	0.0047	4.96	0.70	16.30%	2.92%	2.90%
Sub-Total: Retail Transmission			**11.10**			**11.48**	**0.38**	**3.44%**	**6.76%**	**6.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**67.99**			**70.02**	**2.03**	**2.99%**	**41.24%**	**40.89%**
Sub-Total: Delivery (based on TOU prices)			**67.46**			**69.49**	**2.03**	**3.01%**	**40.93%**	**40.59%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.26%	2.24%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.19%	0.19%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.15%	0.15%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.60%**	**2.58%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.12%**	**4.09%**
Total Electricty Charge on Two-Tier RPP			**159.65**			**161.68**	**2.03**	**1.27%**	**95.24%**	
HST		0.13	20.75		0.13	21.02	0.26	1.27%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**180.40**			**182.70**	**2.29**	**1.27%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.77		-0.08	-12.93	-0.16	-1.27%	-7.62%	
Total Amount on Two-Tier RPP			**167.63**			**169.76**	**2.13**	**1.27%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**161.03**			**163.06**	**2.03**	**1.26%**		**95.24%**
HST		0.13	20.93		0.13	21.20	0.26	1.26%		12.38%
Total Electricity Charge on TOU (including HST)			**181.97**			**184.26**	**2.29**	**1.26%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.88		-0.08	-13.05	-0.16	-1.26%		-7.62%
Total Amount on TOU			**169.08**			**171.22**	**2.13**	**1.26%**		**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2134
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.85%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	34.77%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**52.61%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		26.72%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.21%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		15.03%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**50.78%**	**51.96%**
Service Charge	1	23.3	23.30	1	23.88	23.88	0.58	2.49%	7.38%	7.55%
Fixed Deferral/Variance Account Rider	1	0.67	0.67	1	0.01	0.01	-0.66	-98.81%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0262	52.40	2,000	0.0278	55.60	3.20	6.11%	17.18%	17.58%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	-0.0001	-0.20	2,000	0.0000	0.06	0.26	130.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**76.17**			**79.55**	**3.38**	**4.43%**	**24.58%**	**25.15%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	134	0.0900	12.06	134	0.0900	12.06	0.00	0.00%	3.73%	3.81%
Line Losses on Cost of Power (based on TOU prices)	134	0.0822	11.01	134	0.0822	11.01	0.00	0.00%	3.40%	3.48%
Sub-Total: Distribution (based on two-tier RPP prices)			**89.02**			**92.40**	**3.38**	**3.79%**	**28.55%**	**29.22%**
Sub-Total: Distribution (based on TOU prices)			**87.97**			**91.35**	**3.38**	**3.84%**	**28.23%**	**28.88%**
Retail Transmission Rate – Network Service Rate	2,134	0.0064	13.66	2,134	0.0061	13.03	-0.63	-4.59%	4.03%	4.12%
Retail Transmission Rate – Line and Transformation Connection S	2,134	0.0040	8.54	2,134	0.0047	9.93	1.39	16.30%	3.07%	3.14%
Sub-Total: Retail Transmission			**22.19**			**22.96**	**0.76**	**3.44%**	**7.09%**	**7.26%**
Sub-Total: Delivery (based on two-tier RPP prices)			**111.21**			**115.36**	**4.14**	**3.72%**	**35.65%**	**36.48%**
Sub-Total: Delivery (based on TOU prices)			**110.16**			**114.31**	**4.14**	**3.76%**	**35.32%**	**36.14%**
Wholesale Market Service Rate	2,134	0.0036	7.68	2,134	0.0036	7.68	0.00	0.00%	2.37%	2.43%
Rural Rate Protection Charge	2,134	0.0003	0.64	2,134	0.0003	0.64	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,134	0.0000	0.00	2,134	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.65%**	**2.71%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.33%**	**4.43%**
Total Electricty Charge on Two-Tier RPP			**304.04**			**308.18**	**4.14**	**1.36%**	**95.24%**	
HST		0.13	39.52		0.13	40.06	0.54	1.36%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**343.56**			**348.24**	**4.68**	**1.36%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.32		-0.08	-24.65	-0.33	-1.36%	-7.62%	
Total Amount on Two-Tier RPP			**319.24**			**323.59**	**4.35**	**1.36%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**297.06**			**301.20**	**4.14**	**1.39%**		**95.24%**
HST		0.13	38.62		0.13	39.16	0.54	1.39%		12.38%
Total Electricity Charge on TOU (including HST)			**335.67**			**340.35**	**4.68**	**1.39%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.76		-0.08	-24.10	-0.33	-1.39%		-7.62%
Total Amount on TOU			**311.91**			**316.26**	**4.35**	**1.39%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2759
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2944
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	13.11%	
Energy Second Tier (kWh)	2,009	0.090	180.81	2,009	0.090	180.81	0.00	0.00%	41.06%	
Sub-Total: Energy (RPP)			**238.56**			**238.56**	**0.00**	**0.00%**	**54.18%**	
TOU-Off Peak	1,793	0.065	116.57	1,793	0.065	116.57	0.00	0.00%		27.34%
TOU-Mid Peak	469	0.095	44.56	469	0.095	44.56	0.00	0.00%		10.45%
TOU-On Peak	497	0.132	65.55	497	0.132	65.55	0.00	0.00%		15.38%
Sub-Total: Energy (TOU)			**226.68**			**226.68**	0.00	0.00%	**51.48%**	**53.17%**
Service Charge	1	23.3	23.30	1	23.88	23.88	0.58	2.49%	5.42%	5.60%
Fixed Deferral/Variance Account Rider	1	0.67	0.67	1	0.01	0.01	-0.66	-98.81%	0.00%	0.00%
Distribution Volumetric Rate	2,759	0.0262	72.29	2,759	0.0278	76.70	4.41	6.11%	17.42%	17.99%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,759	-0.0001	-0.28	2,759	0.0000	0.08	0.36	130.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**95.98**			**100.67**	**4.69**	**4.89%**	**22.86%**	**23.61%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.18%	0.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	185	0.0900	16.64	185	0.0900	16.64	0.00	0.00%	3.78%	3.90%
Line Losses on Cost of Power (based on TOU prices)	185	0.0822	15.19	185	0.0822	15.19	0.00	0.00%	3.45%	3.56%
Sub-Total: Distribution (based on two-tier RPP prices)			**113.41**			**118.10**	**4.69**	**4.14%**	**26.82%**	**27.70%**
Sub-Total: Distribution (based on TOU prices)			**111.96**			**116.65**	**4.69**	**4.19%**	**26.49%**	**27.36%**
Retail Transmission Rate – Network Service Rate	2,944	0.0064	18.84	2,944	0.0061	17.98	-0.87	-4.59%	4.08%	4.22%
Retail Transmission Rate – Line and Transformation Connection S	2,944	0.0040	11.78	2,944	0.0047	13.69	1.92	16.30%	3.11%	3.21%
Sub-Total: Retail Transmission			**30.62**			**31.67**	**1.05**	**3.44%**	**7.19%**	**7.43%**
Sub-Total: Delivery (based on two-tier RPP prices)			**144.02**			**149.77**	**5.74**	**3.99%**	**34.01%**	**35.13%**
Sub-Total: Delivery (based on TOU prices)			**142.57**			**148.32**	**5.74**	**4.03%**	**33.68%**	**34.79%**
Wholesale Market Service Rate	2,944	0.0036	10.60	2,944	0.0036	10.60	0.00	0.00%	2.41%	2.49%
Rural Rate Protection Charge	2,944	0.0003	0.88	2,944	0.0003	0.88	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	2,944	0.0000	0.00	2,944	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.73**			**11.73**	**0.00**	**0.00%**	**2.66%**	**2.75%**
Debt Retirement Charge (DRC)	2,759	0.007	**19.31**	2,759	0.007	**19.31**	**0.00**	**0.00%**	**4.39%**	**4.53%**
Total Electricty Charge on Two-Tier RPP			**413.63**			**419.37**	**5.74**	**1.39%**	**95.24%**	
HST		0.13	53.77		0.13	54.52	0.75	1.39%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**467.40**			**473.89**	**6.49**	**1.39%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.09		-0.08	-33.55	-0.46	-1.39%	-7.62%	
Total Amount on Two-Tier RPP			**434.31**			**440.34**	**6.03**	**1.39%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**400.30**			**406.04**	**5.74**	**1.44%**		**95.24%**
HST		0.13	52.04		0.13	52.79	0.75	1.44%		12.38%
Total Electricity Charge on TOU (including HST)			**452.34**			**458.83**	**6.49**	**1.44%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-32.02		-0.08	-32.48	-0.46	-1.44%		-7.62%
Total Amount on TOU			**420.31**			**426.34**	**6.03**	**1.44%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16005
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.49%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	55.20%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**57.69%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		28.78%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.00%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		16.19%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	**0.00**	**0.00%**	**53.04%**	**55.97%**
Service Charge	1	23.3	23.30	1	23.88	23.88	0.58	2.49%	1.03%	1.08%
Fixed Deferral/Variance Account Rider	1	0.67	0.67	1	0.01	0.01	-0.66	-98.81%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0262	393.00	15,000	0.0278	417.00	24.00	6.11%	17.95%	18.94%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	-0.0001	-1.50	15,000	0.0000	0.45	1.95	130.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**415.47**			**441.34**	**25.87**	**6.23%**	**19.00%**	**20.04%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,005	0.0900	90.45	1,005	0.0900	90.45	0.00	0.00%	3.89%	4.11%
Line Losses on Cost of Power (based on TOU prices)	1,005	0.0822	82.57	1,005	0.0822	82.57	0.00	0.00%	3.55%	3.75%
Sub-Total: Distribution (based on two-tier RPP prices)			**506.71**			**532.58**	**25.87**	**5.11%**	**22.92%**	**24.19%**
Sub-Total: Distribution (based on TOU prices)			**498.83**			**524.70**	**25.87**	**5.19%**	**22.58%**	**23.83%**
Retail Transmission Rate – Network Service Rate	16,005	0.0064	102.43	16,005	0.0061	97.73	-4.71	-4.59%	4.21%	4.44%
Retail Transmission Rate – Line and Transformation Connection S	16,005	0.0040	64.02	16,005	0.0047	74.46	10.44	16.30%	3.20%	3.38%
Sub-Total: Retail Transmission			**166.45**			**172.18**	**5.73**	**3.44%**	**7.41%**	**7.82%**
Sub-Total: Delivery (based on two-tier RPP prices)			**673.16**			**704.76**	**31.60**	**4.69%**	**30.33%**	**32.01%**
Sub-Total: Delivery (based on TOU prices)			**665.28**			**696.88**	**31.60**	**4.75%**	**30.00%**	**31.65%**
Wholesale Market Service Rate	16,005	0.0036	57.62	16,005	0.0036	57.62	0.00	0.00%	2.48%	2.62%
Rural Rate Protection Charge	16,005	0.0003	4.80	16,005	0.0003	4.80	0.00	0.00%	0.21%	0.22%
Ontario Electricity Support Program Charge	16,005	0.0000	0.00	16,005	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.67**			**62.67**	**0.00**	**0.00%**	**2.70%**	**2.85%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.52%**	**4.77%**
Total Electricty Charge on Two-Tier RPP			**2,181.08**			**2,212.68**	**31.60**	**1.45%**	**95.24%**	
HST		0.13	283.54		0.13	287.65	4.11	1.45%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,464.62**			**2,500.33**	**35.71**	**1.45%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-174.49		-0.08	-177.01	-2.53	-1.45%	-7.62%	
Total Amount on Two-Tier RPP			**2,290.14**			**2,323.31**	**33.18**	**1.45%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,065.35**			**2,096.95**	**31.60**	**1.53%**		**95.24%**
HST		0.13	268.50		0.13	272.60	4.11	1.53%		12.38%
Total Electricity Charge on TOU (including HST)			**2,333.85**			**2,369.55**	**35.71**	**1.53%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-165.23		-0.08	-167.76	-2.53	-1.53%		-7.62%
Total Amount on TOU			**2,168.62**			**2,201.80**	**33.18**	**1.53%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1096
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	27.39%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	10.67%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**38.06%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.92%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.61%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		11.20%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**38.96%**	**38.74%**
Service Charge	1	27.87	27.87	1	29.56	29.56	1.69	6.06%	14.02%	13.94%
Fixed Deferral/Variance Account Rider	1	0.73	0.73	1	0.00	0.00	-0.73	-99.73%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0560	56.00	1,000	0.0589	58.90	2.90	5.18%	27.93%	27.77%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0002	0.20	1,000	0.0000	0.02	-0.18	-90.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**84.80**			**88.48**	**3.68**	**4.34%**	**41.96%**	**41.72%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.37%	0.37%
Line Losses on Cost of Power (based on two-tier RPP prices)	96	0.0900	8.64	96	0.0900	8.64	0.00	0.00%	4.10%	4.07%
Line Losses on Cost of Power (based on TOU prices)	96	0.0822	7.89	96	0.0822	7.89	0.00	0.00%	3.74%	3.72%
Sub-Total: Distribution (based on two-tier RPP prices)			**94.23**			**97.91**	**3.68**	**3.91%**	**46.43%**	**46.17%**
Sub-Total: Distribution (based on TOU prices)			**93.48**			**97.16**	**3.68**	**3.94%**	**46.08%**	**45.81%**
Retail Transmission Rate – Network Service Rate	1,096	0.0059	6.47	1,096	0.0057	6.24	-0.23	-3.51%	2.96%	2.94%
Retail Transmission Rate – Line and Transformation Connection S	1,096	0.0038	4.16	1,096	0.0045	4.90	0.74	17.74%	2.33%	2.31%
Sub-Total: Retail Transmission			**10.63**			**11.14**	**0.51**	**4.81%**	**5.28%**	**5.25%**
Sub-Total: Delivery (based on two-tier RPP prices)			**104.86**			**109.06**	**4.19**	**4.00%**	**51.72%**	**51.42%**
Sub-Total: Delivery (based on TOU prices)			**104.11**			**108.30**	**4.19**	**4.03%**	**51.36%**	**51.07%**
Wholesale Market Service Rate	1,096	0.0036	3.95	1,096	0.0036	3.95	0.00	0.00%	1.87%	1.86%
Rural Rate Protection Charge	1,096	0.0003	0.33	1,096	0.0003	0.33	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	1,096	0.0000	0.00	1,096	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.12%
Sub-Total: Regulatory			**4.52**			**4.52**	**0.00**	**0.00%**	**2.15%**	**2.13%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.32%**	**3.30%**
Total Electricty Charge on Two-Tier RPP			**196.64**			**200.83**	**4.19**	**2.13%**	**95.24%**	
HST		0.13	25.56		0.13	26.11	0.55	2.13%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**222.20**			**226.94**	**4.74**	**2.13%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.73		-0.08	-16.07	-0.34	-2.13%	-7.62%	
Total Amount on Two-Tier RPP			**206.47**			**210.87**	**4.40**	**2.13%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**197.79**			**201.99**	**4.19**	**2.12%**		**95.24%**
HST		0.13	25.71		0.13	26.26	0.55	2.12%		12.38%
Total Electricity Charge on TOU (including HST)			**223.51**			**228.25**	**4.74**	**2.12%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.82		-0.08	-16.16	-0.34	-2.12%		-7.62%
Total Amount on TOU			**207.68**			**212.09**	**4.40**	**2.12%**		**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2192
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.44%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	28.14%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**42.58%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		21.55%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		8.24%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		12.12%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**41.10%**	**41.91%**
Service Charge	1	27.87	27.87	1	29.56	29.56	1.69	6.06%	7.39%	7.54%
Fixed Deferral/Variance Account Rider	1	0.73	0.73	1	0.00	0.00	-0.73	-99.73%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0560	112.00	2,000	0.0589	117.80	5.80	5.18%	29.46%	30.05%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0002	0.40	2,000	0.0000	0.04	-0.36	-90.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**141.00**			**147.40**	**6.40**	**4.54%**	**36.86%**	**37.60%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.20%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	192	0.0900	17.28	192	0.0900	17.28	0.00	0.00%	4.32%	4.41%
Line Losses on Cost of Power (based on TOU prices)	192	0.0822	15.77	192	0.0822	15.77	0.00	0.00%	3.95%	4.02%
Sub-Total: Distribution (based on two-tier RPP prices)			**159.07**			**165.47**	**6.40**	**4.02%**	**41.38%**	**42.21%**
Sub-Total: Distribution (based on TOU prices)			**157.56**			**163.97**	**6.40**	**4.06%**	**41.01%**	**41.82%**
Retail Transmission Rate – Network Service Rate	2,192	0.0059	12.93	2,192	0.0057	12.48	-0.45	-3.51%	3.12%	3.18%
Retail Transmission Rate – Line and Transformation Connection S	2,192	0.0038	8.33	2,192	0.0045	9.81	1.48	17.74%	2.45%	2.50%
Sub-Total: Retail Transmission			**21.26**			**22.29**	**1.02**	**4.81%**	**5.57%**	**5.68%**
Sub-Total: Delivery (based on two-tier RPP prices)			**180.33**			**187.76**	**7.43**	**4.12%**	**46.96%**	**47.89%**
Sub-Total: Delivery (based on TOU prices)			**178.83**			**186.25**	**7.43**	**4.15%**	**46.58%**	**47.51%**
Wholesale Market Service Rate	2,192	0.0036	7.89	2,192	0.0036	7.89	0.00	0.00%	1.97%	2.01%
Rural Rate Protection Charge	2,192	0.0003	0.66	2,192	0.0003	0.66	0.00	0.00%	0.16%	0.17%
Ontario Electricity Support Program Charge	2,192	0.0000	0.00	2,192	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.80**			**8.80**	**0.00**	**0.00%**	**2.20%**	**2.24%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.50%**	**3.57%**
Total Electricty Charge on Two-Tier RPP			**373.38**			**380.81**	**7.43**	**1.99%**	**95.24%**	
HST		0.13	48.54		0.13	49.50	0.97	1.99%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**421.92**			**430.31**	**8.39**	**1.99%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.87		-0.08	-30.46	-0.59	-1.99%	-7.62%	
Total Amount on Two-Tier RPP			**392.05**			**399.85**	**7.80**	**1.99%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**365.95**			**373.37**	**7.43**	**2.03%**		**95.24%**
HST		0.13	47.57		0.13	48.54	0.97	2.03%		12.38%
Total Electricity Charge on TOU (including HST)			**413.52**			**421.91**	**8.39**	**2.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.28		-0.08	-29.87	-0.59	-2.03%		-7.62%
Total Amount on TOU			**384.24**			**392.04**	**7.80**	**2.03%**		**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1982
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2172
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.57%	
Energy Second Tier (kWh)	1,232	0.090	110.88	1,232	0.090	110.88	0.00	0.00%	27.97%	
Sub-Total: Energy (RPP)			**168.63**			**168.63**	**0.00**	**0.00%**	**42.54%**	
TOU-Off Peak	1,288	0.065	83.74	1,288	0.065	83.74	0.00	0.00%		21.54%
TOU-Mid Peak	337	0.095	32.01	337	0.095	32.01	0.00	0.00%		8.23%
TOU-On Peak	357	0.132	47.09	357	0.132	47.09	0.00	0.00%		12.11%
Sub-Total: Energy (TOU)			**162.84**			**162.84**	0.00	0.00%	**41.08%**	**41.88%**
Service Charge	1	27.87	27.87	1	29.56	29.56	1.69	6.06%	7.46%	7.60%
Fixed Deferral/Variance Account Rider	1	0.73	0.73	1	0.00	0.00	-0.73	-99.73%	0.00%	0.00%
Distribution Volumetric Rate	1,982	0.0560	110.99	1,982	0.0589	116.74	5.75	5.18%	29.45%	30.03%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,982	0.0002	0.40	1,982	0.0000	0.04	-0.36	-90.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**139.99**			**146.34**	**6.35**	**4.54%**	**36.91%**	**37.64%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.20%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	190	0.0900	17.12	190	0.0900	17.12	0.00	0.00%	4.32%	4.40%
Line Losses on Cost of Power (based on TOU prices)	190	0.0822	15.63	190	0.0822	15.63	0.00	0.00%	3.94%	4.02%
Sub-Total: Distribution (based on two-tier RPP prices)			**157.90**			**164.26**	**6.35**	**4.02%**	**41.43%**	**42.25%**
Sub-Total: Distribution (based on TOU prices)			**156.41**			**162.76**	**6.35**	**4.06%**	**41.06%**	**41.86%**
Retail Transmission Rate – Network Service Rate	2,172	0.0059	12.82	2,172	0.0057	12.37	-0.45	-3.51%	3.12%	3.18%
Retail Transmission Rate – Line and Transformation Connection S	2,172	0.0038	8.25	2,172	0.0045	9.72	1.46	17.74%	2.45%	2.50%
Sub-Total: Retail Transmission			**21.07**			**22.09**	**1.01**	**4.81%**	**5.57%**	**5.68%**
Sub-Total: Delivery (based on two-tier RPP prices)			**178.97**			**186.34**	**7.37**	**4.12%**	**47.00%**	**47.93%**
Sub-Total: Delivery (based on TOU prices)			**177.48**			**184.85**	**7.37**	**4.15%**	**46.63%**	**47.54%**
Wholesale Market Service Rate	2,172	0.0036	7.82	2,172	0.0036	7.82	0.00	0.00%	1.97%	2.01%
Rural Rate Protection Charge	2,172	0.0003	0.65	2,172	0.0003	0.65	0.00	0.00%	0.16%	0.17%
Ontario Electricity Support Program Charge	2,172	0.0000	0.00	2,172	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.72**			**8.72**	**0.00**	**0.00%**	**2.20%**	**2.24%**
Debt Retirement Charge (DRC)	1,982	0.007	**13.87**	1,982	0.007	**13.87**	**0.00**	**0.00%**	**3.50%**	**3.57%**
Total Electricty Charge on Two-Tier RPP			**370.20**			**377.57**	**7.37**	**1.99%**	**95.24%**	
HST		0.13	48.13		0.13	49.08	0.96	1.99%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**418.33**			**426.65**	**8.33**	**1.99%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.62		-0.08	-30.21	-0.59	-1.99%	-7.62%	
Total Amount on Two-Tier RPP			**388.71**			**396.45**	**7.74**	**1.99%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**362.92**			**370.29**	**7.37**	**2.03%**		**95.24%**
HST		0.13	47.18		0.13	48.14	0.96	2.03%		12.38%
Total Electricity Charge on TOU (including HST)			**410.10**			**418.42**	**8.33**	**2.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.03		-0.08	-29.62	-0.59	-2.03%		-7.62%
Total Amount on TOU			**381.07**			**388.80**	**7.74**	**2.03%**		**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16440
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.02%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	44.90%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**46.92%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		23.20%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		8.87%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		13.05%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**43.14%**	**45.12%**
Service Charge	1	27.87	27.87	1	29.56	29.56	1.69	6.06%	1.03%	1.08%
Fixed Deferral/Variance Account Rider	1	0.73	0.73	1	0.00	0.00	-0.73	-99.73%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0560	840.00	15,000	0.0589	883.50	43.50	5.18%	30.93%	32.35%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0002	3.00	15,000	0.0000	0.30	-2.70	-90.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**871.60**			**913.36**	**41.76**	**4.79%**	**31.97%**	**33.44%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,440	0.0900	129.60	1,440	0.0900	129.60	0.00	0.00%	4.54%	4.74%
Line Losses on Cost of Power (based on TOU prices)	1,440	0.0822	118.31	1,440	0.0822	118.31	0.00	0.00%	4.14%	4.33%
Sub-Total: Distribution (based on two-tier RPP prices)			**1,001.99**			**1,043.75**	**41.76**	**4.17%**	**36.54%**	**38.21%**
Sub-Total: Distribution (based on TOU prices)			**990.70**			**1,032.46**	**41.76**	**4.22%**	**36.14%**	**37.80%**
Retail Transmission Rate – Network Service Rate	16,440	0.0059	97.00	16,440	0.0057	93.59	-3.40	-3.51%	3.28%	3.43%
Retail Transmission Rate – Line and Transformation Connection S	16,440	0.0038	62.47	16,440	0.0045	73.55	11.08	17.74%	2.57%	2.69%
Sub-Total: Retail Transmission			**159.47**			**167.15**	**7.68**	**4.81%**	**5.85%**	**6.12%**
Sub-Total: Delivery (based on two-tier RPP prices)			**1,161.46**			**1,210.90**	**49.44**	**4.26%**	**42.39%**	**44.33%**
Sub-Total: Delivery (based on TOU prices)			**1,150.17**			**1,199.61**	**49.44**	**4.30%**	**42.00%**	**43.92%**
Wholesale Market Service Rate	16,440	0.0036	59.18	16,440	0.0036	59.18	0.00	0.00%	2.07%	2.17%
Rural Rate Protection Charge	16,440	0.0003	4.93	16,440	0.0003	4.93	0.00	0.00%	0.17%	0.18%
Ontario Electricity Support Program Charge	16,440	0.0000	0.00	16,440	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**64.37**			**64.37**	**0.00**	**0.00%**	**2.25%**	**2.36%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.68%**	**3.84%**
Total Electricty Charge on Two-Tier RPP			**2,671.07**			**2,720.51**	**49.44**	**1.85%**	**95.24%**	
HST		0.13	347.24		0.13	353.67	6.43	1.85%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**3,018.31**			**3,074.18**	**55.87**	**1.85%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-213.69		-0.08	-217.64	**-3.96**	-1.85%	-7.62%	
Total Amount on Two-Tier RPP			**2,804.63**			**2,856.54**	**51.91**	**1.85%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,551.93**			**2,601.37**	**49.44**	**1.94%**		**95.24%**
HST		0.13	331.75		0.13	338.18	6.43	1.94%		12.38%
Total Electricity Charge on TOU (including HST)			**2,883.69**			**2,939.55**	**55.87**	**1.94%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-204.15		-0.08	-208.11	-3.96	-1.94%		-7.62%
Total Amount on TOU			**2,679.53**			**2,731.44**	**51.91**	**1.94%**		**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.050
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,750	0.077	1,212.75	15,750	0.077	1,212.75	0.00	0.00%	46.78%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,212.75**			**1,212.75**	**0.00**	**0.00%**	**46.78%**
Service Charge	1	93.97	93.97	1	100.72	100.72	6.75	7.18%	3.88%
Fixed Deferral/Variance Account Rider	1	1.42	1.42	1	0.018	0.02	-1.40	-98.73%	0.00%
Distribution Volumetric Rate	60	9.1837	551.02	60	9.6226	577.36	26.33	4.78%	22.27%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	-0.0623	-3.74	60	0.0112	0.67	4.41	117.95%	0.03%
Volumetric Global Adjustment Account Rider	15,750	-0.0010	-15.75	15,750	0.0000	0.00	15.75	100.00%	0.00%
Sub-Total: Distribution			**626.92**			**678.76**	**51.84**	**8.27%**	**26.18%**
Retail Transmission Rate – Network Service Rate	60	2.1129	126.77	60	2.2310	133.86	7.09	5.59%	5.16%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.3901	83.41	60	1.7047	102.28	18.87	22.63%	3.95%
Sub-Total: Retail Transmission			**210.18**			**236.14**	**25.96**	**12.35%**	**9.11%**
Sub-Total: Delivery			**837.10**			**914.91**	**77.80**	**9.29%**	**35.29%**
Wholesale Market Service Rate	15,750	0.0036	56.70	15,750	0.0036	56.70	0.00	0.00%	2.19%
Rural Rate Protection Charge	15,750	0.0003	4.73	15,750	0.0003	4.73	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.68**			**61.68**	**0.00**	**0.00%**	**2.38%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.05%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,216.53**			**2,294.33**	**77.80**	**3.51%**	**88.50%**
HST		0.13	288.15		0.13	298.26	10.11	3.51%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,504.68**			**2,592.60**	**87.92**	**3.51%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,504.68**			**2,592.60**	**87.92**	**3.51%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	50,525
Peak (kW)	135
Loss factor	1.050
Load factor	51%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	53,051
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	53,051	0.077	4,084.95	53,051	0.077	4,084.95	0.00	0.00%	54.95%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,084.95**			**4,084.95**	**0.00**	**0.00%**	**54.95%**
Service Charge	1	93.97	93.97	1	100.72	100.72	6.75	7.18%	1.35%
Fixed Deferral/Variance Account Rider	1	1.42	1.42	1	0.018	0.02	-1.40	-98.73%	0.00%
Distribution Volumetric Rate	135	9.1837	1,239.80	135	9.6226	1,299.05	59.25	4.78%	17.48%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	135	-0.0623	-8.41	135	0.0112	1.51	9.92	117.95%	0.02%
Volumetric Global Adjustment Account Rider	53,051	-0.0010	-53.05	53,051	0.0000	0.00	53.05	100.00%	0.00%
Sub-Total: Distribution			**1,273.73**			**1,401.30**	**127.57**	**10.02%**	**18.85%**
Retail Transmission Rate – Network Service Rate	135	2.1129	285.24	135	2.2310	301.19	15.95	5.59%	4.05%
Retail Transmission Rate – Line and Transformation Connection Service Rate	135	1.3901	187.66	135	1.7047	230.13	42.47	22.63%	3.10%
Sub-Total: Retail Transmission			**472.91**			**531.32**	**58.42**	**12.35%**	**7.15%**
Sub-Total: Delivery			**1,746.63**			**1,932.62**	**185.99**	**10.65%**	**26.00%**
Wholesale Market Service Rate	53,051	0.0036	190.98	53,051	0.0036	190.98	0.00	0.00%	2.57%
Rural Rate Protection Charge	53,051	0.0003	15.92	53,051	0.0003	15.92	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**207.15**			**207.15**	**0.00**	**0.00%**	**2.79%**
Debt Retirement Charge (DRC)	50,525	0.007	**353.68**	50,525	0.007	**353.68**	**0.00**	**0.00%**	**4.76%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,392.40**			**6,578.39**	**185.99**	**2.91%**	**88.50%**
HST		0.13	831.01		0.13	855.19	24.18	2.91%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,223.42**			**7,433.58**	**210.17**	**2.91%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,223.42**			**7,433.58**	**210.17**	**2.91%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.050
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	183,750	0.077	14,148.75	183,750	0.077	14,148.75	0.00	0.00%	54.50%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,148.75**			**14,148.75**	**0.00**	**0.00%**	**54.50%**
Service Charge	1	93.97	93.97	1	100.72	100.72	6.75	7.18%	0.39%
Fixed Deferral/Variance Account Rider	1	1.42	1.42	1	0.018	0.02	-1.40	-98.73%	0.00%
Distribution Volumetric Rate	500	9.1837	4,591.85	500	9.6226	4,811.30	219.45	4.78%	18.53%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	-0.0623	-31.15	500	0.0112	5.59	36.74	117.95%	0.02%
Volumetric Global Adjustment Account Rider	183,750	-0.0010	-183.75	183,750	0.0000	0.00	183.75	100.00%	0.00%
Sub-Total: Distribution			**4,472.34**			**4,917.63**	**445.29**	**9.96%**	**18.94%**
Retail Transmission Rate – Network Service Rate	500	2.1129	1,056.45	500	2.2310	1,115.52	59.07	5.59%	4.30%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.3901	695.05	500	1.7047	852.34	157.29	22.63%	3.28%
Sub-Total: Retail Transmission			**1,751.50**			**1,967.86**	**216.36**	**12.35%**	**7.58%**
Sub-Total: Delivery			**6,223.84**			**6,885.49**	**661.65**	**10.63%**	**26.52%**
Wholesale Market Service Rate	183,750	0.0036	661.50	183,750	0.0036	661.50	0.00	0.00%	2.55%
Rural Rate Protection Charge	183,750	0.0003	55.13	183,750	0.0003	55.13	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**716.88**			**716.88**	**0.00**	**0.00%**	**2.76%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.72%**
Total Electricity Charge on Two-Tier RPP (before HST)			**22,314.47**			**22,976.11**	**661.65**	**2.97%**	**88.50%**
HST		0.13	2,900.88		0.13	2,986.89	86.01	2.97%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**25,215.35**			**25,963.00**	**747.66**	**2.97%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**25,215.35**			**25,963.00**	**747.66**	**2.97%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.061
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,915
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,915	0.077	1,225.46	15,915	0.077	1,225.46	0.00	0.00%	40.49%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,225.46**			**1,225.46**	**0.00**	**0.00%**	**40.49%**
Service Charge	1	89.48	89.48	1	102.52	102.52	13.04	14.57%	3.39%
Fixed Deferral/Variance Account Rider	1	1.37	1.37	1	-0.009	-0.01	-1.38	-100.66%	0.00%
Distribution Volumetric Rate	60	16.0236	961.42	60	16.7689	1,006.13	44.72	4.65%	33.24%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0428	2.57	60	0.0052	0.31	-2.26	-87.94%	0.01%
Volumetric Global Adjustment Account Rider	15,915	-0.0010	-15.92	15,915	0.0000	0.00	15.92	100.00%	0.00%
Sub-Total: Distribution			**1,038.92**			**1,108.95**	**70.04**	**6.74%**	**36.64%**
Retail Transmission Rate – Network Service Rate	60	1.7027	102.16	60	1.6718	100.31	-1.85	-1.81%	3.31%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.1398	68.39	60	1.2769	76.61	8.23	12.03%	2.53%
Sub-Total: Retail Transmission			**170.55**			**176.92**	**6.37**	**3.74%**	**5.85%**
Sub-Total: Delivery			**1,209.47**			**1,285.88**	**76.41**	**6.32%**	**42.48%**
Wholesale Market Service Rate	15,915	0.0036	57.29	15,915	0.0036	57.29	0.00	0.00%	1.89%
Rural Rate Protection Charge	15,915	0.0003	4.77	15,915	0.0003	4.77	0.00	0.00%	0.16%
Ontario Electricity Support Program Charge	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.32**			**62.32**	**0.00**	**0.00%**	**2.06%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.47%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,602.24**			**2,678.65**	**76.41**	**2.94%**	**88.50%**
HST		0.13	338.29		0.13	348.22	9.93	2.94%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,940.53**			**3,026.88**	**86.34**	**2.94%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,940.53**			**3,026.88**	**86.34**	**2.94%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	36,104
Peak (kW)	124
Loss factor	1.061
Load factor	40%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	38,306
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	38,306	0.077	2,949.59	38,306	0.077	2,949.59	0.00	0.00%	44.24%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**2,949.59**			**2,949.59**	**0.00**	**0.00%**	**44.24%**
Service Charge	1	89.48	89.48	1	102.52	102.52	13.04	14.57%	1.54%
Fixed Deferral/Variance Account Rider	1	1.37	1.37	1	-0.009	-0.01	-1.38	-100.66%	0.00%
Distribution Volumetric Rate	124	16.0236	1,986.93	124	16.7689	2,079.34	92.42	4.65%	31.19%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	124	0.0428	5.31	124	0.0052	0.64	-4.67	-87.94%	0.01%
Volumetric Global Adjustment Account Rider	38,306	-0.0010	-38.31	38,306	0.0000	0.00	38.31	100.00%	0.00%
Sub-Total: Distribution			**2,044.78**			**2,182.49**	**137.72**	**6.74%**	**32.74%**
Retail Transmission Rate – Network Service Rate	124	1.7027	211.13	124	1.6718	207.31	-3.83	-1.81%	3.11%
Retail Transmission Rate – Line and Transformation Connection Service Rate	124	1.1398	141.34	124	1.2769	158.34	17.00	12.03%	2.37%
Sub-Total: Retail Transmission			**352.47**			**365.64**	**13.17**	**3.74%**	**5.48%**
Sub-Total: Delivery			**2,397.25**			**2,548.14**	**150.89**	**6.29%**	**38.22%**
Wholesale Market Service Rate	38,306	0.0036	137.90	38,306	0.0036	137.90	0.00	0.00%	2.07%
Rural Rate Protection Charge	38,306	0.0003	11.49	38,306	0.0003	11.49	0.00	0.00%	0.17%
Ontario Electricity Support Program Charge	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**149.64**			**149.64**	**0.00**	**0.00%**	**2.24%**
Debt Retirement Charge (DRC)	36,104	0.007	**252.73**	36,104	0.007	**252.73**	**0.00**	**0.00%**	**3.79%**
Total Electricity Charge on Two-Tier RPP (before HST)			**5,749.21**			**5,900.10**	**150.89**	**2.62%**	**88.50%**
HST		0.13	747.40		0.13	767.01	19.62	2.62%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**6,496.61**			**6,667.11**	**170.51**	**2.62%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**6,496.61**			**6,667.11**	**170.51**	**2.62%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.061
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	185,675
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	185,675	0.077	14,296.98	185,675	0.077	14,296.98	0.00	0.00%	48.27%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,296.98**			**14,296.98**	**0.00**	**0.00%**	**48.27%**
Service Charge	1	89.48	89.48	1	102.52	102.52	13.04	14.57%	0.35%
Fixed Deferral/Variance Account Rider	1	1.37	1.37	1	-0.009	-0.01	-1.38	-100.66%	0.00%
Distribution Volumetric Rate	500	16.0236	8,011.80	500	16.7689	8,384.45	372.65	4.65%	28.31%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0428	21.40	500	0.0052	2.58	-18.82	-87.94%	0.01%
Volumetric Global Adjustment Account Rider	185,675	-0.0010	-185.68	185,675	0.0000	0.00	185.68	100.00%	0.00%
Sub-Total: Distribution			**7,938.38**			**8,489.54**	**551.17**	**6.94%**	**28.66%**
Retail Transmission Rate – Network Service Rate	500	1.7027	851.35	500	1.6718	835.91	-15.44	-1.81%	2.82%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.1398	569.90	500	1.2769	638.46	68.56	12.03%	2.16%
Sub-Total: Retail Transmission			**1,421.25**			**1,474.37**	**53.12**	**3.74%**	**4.98%**
Sub-Total: Delivery			**9,359.63**			**9,963.91**	**604.28**	**6.46%**	**33.64%**
Wholesale Market Service Rate	185,675	0.0036	668.43	185,675	0.0036	668.43	0.00	0.00%	2.26%
Rural Rate Protection Charge	185,675	0.0003	55.70	185,675	0.0003	55.70	0.00	0.00%	0.19%
Ontario Electricity Support Program Charge	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**724.38**			**724.38**	**0.00**	**0.00%**	**2.45%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.14%**
Total Electricity Charge on Two-Tier RPP (before HST)			**25,605.98**			**26,210.26**	**604.28**	**2.36%**	**88.50%**
HST		0.13	3,328.78		0.13	3,407.33	78.56	2.36%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**28,934.76**			**29,617.60**	**682.84**	**2.36%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**28,934.76**			**29,617.60**	**682.84**	**2.36%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	DGEN
Monthly Consumption (kWh)	300
Peak (kW)	10
Loss factor	1.061
Load factor	4%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	318
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	318	0.077	24.51	318	0.077	24.51	0.00	0.00%	7.22%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**24.51**			**24.51**	**0.00**	**0.00%**	**7.22%**
Service Charge	1	149.34	149.34	1	196.16	196.16	46.82	31.35%	57.79%
Fixed Deferral/Variance Account Rider	1	2.72	2.72	1	0.011	0.01	-2.71	-99.60%	0.00%
Distribution Volumetric Rate	10	7.0504	70.50	10	6.4310	64.31	-6.19	-8.79%	18.95%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10	0.0633	0.63	10	0.00282	0.03	-0.60	-95.55%	0.01%
Volumetric Global Adjustment Account Rider	318	-0.0010	-0.32	318	0.0000	0.00	0.32	100.00%	0.00%
Sub-Total: Distribution			**222.88**			**260.51**	**37.63**	**16.88%**	**76.75%**
Retail Transmission Rate – Network Service Rate	10	0.5549	5.55	10	0.6311	6.31	0.76	13.73%	1.86%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	0.3553	3.55	10	0.5475	5.47	1.92	54.09%	1.61%
Sub-Total: Retail Transmission			**9.10**			**11.79**	**2.68**	**29.48%**	**3.47%**
Sub-Total: Delivery			**231.98**			**272.29**	**40.31**	**17.38%**	**80.22%**
Wholesale Market Service Rate	318	0.0036	1.15	318	0.0036	1.15	0.00	0.00%	0.34%
Rural Rate Protection Charge	318	0.0003	0.10	318	0.0003	0.10	0.00	0.00%	0.03%
Ontario Electricity Support Program Charge	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%
Sub-Total: Regulatory			**1.49**			**1.49**	**0.00**	**0.00%**	**0.44%**
Debt Retirement Charge (DRC)	300	0.007	**2.10**	300	0.007	**2.10**	**0.00**	**0.00%**	**0.62%**
Total Electricity Charge on Two-Tier RPP (before HST)			**260.08**			**300.40**	**40.31**	**15.50%**	**88.50%**
HST		0.13	33.81		0.13	39.05	5.24	15.50%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**293.89**			**339.45**	**45.55**	**15.50%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**293.89**			**339.45**	**45.55**	**15.50%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	DGEN
Monthly Consumption (kWh)	1,328
Peak (kW)	13
Loss factor	1.061
Load factor	14%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,409
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,409	0.077	108.49	1,409	0.077	108.49	0.00	0.00%	22.93%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**108.49**			**108.49**	**0.00**	**0.00%**	**22.93%**
Service Charge	1	149.34	149.34	1	196.16	196.16	46.82	31.35%	41.46%
Fixed Deferral/Variance Account Rider	1	2.72	2.72	1	0.01	0.01	-2.71	-99.60%	0.00%
Distribution Volumetric Rate	13	7.0504	91.66	13	6.4310	83.60	-8.05	-8.79%	17.67%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	13	0.0633	0.82	13	0.00282	0.04	-0.79	-95.55%	0.01%
Volumetric Global Adjustment Account Rider	1,409	-0.0010	-1.41	1,409	0.0000	0.00	1.41	100.00%	0.00%
Sub-Total: Distribution			**243.13**			**279.81**	**36.68**	**15.09%**	**59.14%**
Retail Transmission Rate – Network Service Rate	13	0.5549	7.21	13	0.6311	8.20	0.99	13.73%	1.73%
Retail Transmission Rate – Line and Transformation Connection Service Rate	13	0.3553	4.62	13	0.5475	7.12	2.50	54.09%	1.50%
Sub-Total: Retail Transmission			**11.83**			**15.32**	**3.49**	**29.48%**	**3.24%**
Sub-Total: Delivery			**254.96**			**295.13**	**40.17**	**15.76%**	**62.38%**
Wholesale Market Service Rate	1,409	0.0036	5.07	1,409	0.0036	5.07	0.00	0.00%	1.07%
Rural Rate Protection Charge	1,409	0.0003	0.42	1,409	0.0003	0.42	0.00	0.00%	0.09%
Ontario Electricity Support Program Charge	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**5.75**			**5.75**	**0.00**	**0.00%**	**1.21%**
Debt Retirement Charge (DRC)	1,328	0.007	**9.30**	1,328	0.007	**9.30**	**0.00**	**0.00%**	**1.96%**
Total Electricity Charge on Two-Tier RPP (before HST)			**378.50**			**418.67**	**40.17**	**10.61%**	**88.50%**
HST		0.13	49.20		0.13	54.43	5.22	10.61%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**427.70**			**473.09**	**45.39**	**10.61%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**427.70**			**473.09**	**45.39**	**10.61%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	DGEN
Monthly Consumption (kWh)	5,000
Peak (kW)	100
Loss factor	1.061
Load factor	7%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	5,305
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	5,305	0.077	408.49	5,305	0.077	408.49	0.00	0.00%	25.42%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**408.49**			**408.49**	**0.00**	**0.00%**	**25.42%**
Service Charge	1	149.34	149.34	1	196.16	196.16	46.82	31.35%	12.21%
Smart Meter Adder	1	0	0.00	1	0	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	100	7.0504	705.04	100	6.4310	643.10	-61.94	-8.79%	40.03%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0633	6.33	100	0.00282	0.28	-6.05	-95.55%	0.02%
Volumetric Global Adjustment Account Rider	5,305	-0.0010	-5.31	5,305	0.0000	0.00	5.31	100.00%	0.00%
Sub-Total: Distribution			**858.13**			**839.55**	**-18.57**	**-2.16%**	**52.25%**
Retail Transmission Rate – Network Service Rate	100	0.5549	55.49	100	0.6311	63.11	7.62	13.73%	3.93%
Retail Transmission Rate – Line and Transformation Connection Service Rate	100	0.3553	35.53	100	0.5475	54.75	19.22	54.09%	3.41%
Sub-Total: Retail Transmission			**91.02**			**117.86**	**26.84**	**29.48%**	**7.34%**
Sub-Total: Delivery			**949.15**			**957.41**	**8.26**	**0.87%**	**59.59%**
Wholesale Market Service Rate	5,305	0.0036	19.10	5,305	0.0036	19.10	0.00	0.00%	1.19%
Rural Rate Protection Charge	5,305	0.0003	1.59	5,305	0.0003	1.59	0.00	0.00%	0.10%
Ontario Electricity Support Program Charge	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.02%
Sub-Total: Regulatory			**20.94**			**20.94**	**0.00**	**0.00%**	**1.30%**
Debt Retirement Charge (DRC)	5,000	0.007	**35.00**	5,000	0.007	**35.00**	**0.00**	**0.00%**	**2.18%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,413.57**			**1,421.83**	**8.26**	**0.58%**	**88.50%**
HST		0.13	183.76		0.13	184.84	1.07	0.58%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**1,597.33**			**1,606.67**	**9.34**	**0.58%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**1,597.33**			**1,606.67**	**9.34**	**0.58%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	200,000
Peak (kW)	500
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	206,800
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	206,800	0.077	15,923.60	206,800	0.077	15,923.60	0.00	0.00%	61.36%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15,923.60**			**15,923.60**	**0.00**	**0.00%**	**61.36%**
Service Charge	1	1256.56	1,256.56	1	1199.21	1,199.21	-57.35	-4.56%	4.62%
Fixed Deferral/Variance Account Rider	1	11.86	11.86	1	3.82	3.82	-8.04	-67.80%	0.01%
Distribution Volumetric Rate	500	1.2052	602.60	500	1.3103	655.13	52.53	8.72%	2.52%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.3126	156.30	500	-0.1367	-68.34	-224.64	-143.72%	-0.26%
Volumetric Global Adjustment Account Rider	206,800	-0.0010	-206.80	206,800	0	0.00	206.80	100.00%	0.00%
Sub-Total: Distribution			**1,820.52**			**1,789.82**	**-30.70**	**-1.69%**	**6.90%**
Retail Transmission Rate – Network Service Rate	500	3.3028	1,651.40	500	3.4866	1,743.32	91.92	5.57%	6.72%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.6060	1,303.00	500	2.6022	1,301.08	-1.92	-0.15%	5.01%
Sub-Total: Retail Transmission			**2,954.40**			**3,044.41**	**90.01**	**3.05%**	**11.73%**
Sub-Total: Delivery			**4,774.92**			**4,834.23**	**59.31**	**1.24%**	**18.63%**
Wholesale Market Service Rate	206,800	0.0036	744.48	206,800	0.0036	744.48	0.00	0.00%	2.87%
Rural Rate Protection Charge	206,800	0.0003	62.04	206,800	0.0003	62.04	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**806.77**			**806.77**	**0.00**	**0.00%**	**3.11%**
Debt Retirement Charge (DRC)	200,000	0.007	**1,400.00**	200,000	0.007	**1,400.00**	**0.00**	**0.00%**	**5.39%**
Total Electricity Charge on Two-Tier RPP (before HST)			**22,905.29**			**22,964.60**	**59.31**	**0.26%**	**88.50%**
HST		0.13	2,977.69		0.13	2,985.40	7.71	0.26%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**25,882.98**			**25,950.00**	**67.02**	**0.26%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**25,882.98**			**25,950.00**	**67.02**	**0.26%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	1,601,036
Peak (kW)	3,091
Loss factor	1.034
Load factor	71%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,655,471
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,655,471	0.077	127,471.28	1,655,471	0.077	127,471.28	0.00	0.00%	66.83%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**127,471.28**			**127,471.28**	**0.00**	**0.00%**	**66.83%**
Service Charge	1	1256.56	1,256.56	1	1199.21	1,199.21	-57.35	-4.56%	0.63%
Fixed Deferral/Variance Account Rider	1	11.86	11.86	1	3.82	3.82	-8.04	-67.80%	0.00%
Distribution Volumetric Rate	3,091	1.2052	3,725.27	3,091	1.3103	4,050.01	324.74	8.72%	2.12%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	3,091	0.3126	966.25	3,091	-0.1367	-422.45	-1,388.69	-143.72%	-0.22%
Volumetric Global Adjustment Account Rider	1,655,471	-0.0010	-1,655.47	1,655,471	0	0.00	1,655.47	100.00%	0.00%
Sub-Total: Distribution			**4,304.47**			**4,830.59**	**526.12**	**12.22%**	**2.53%**
Retail Transmission Rate – Network Service Rate	3,091	3.3028	10,208.95	3,091	3.4866	10,777.23	568.27	5.57%	5.65%
Retail Transmission Rate – Line and Transformation Connection Service Rate	3,091	2.6060	8,055.15	3,091	2.6022	8,043.29	-11.86	-0.15%	4.22%
Sub-Total: Retail Transmission			**18,264.10**			**18,820.52**	**556.42**	**3.05%**	**9.87%**
Sub-Total: Delivery			**22,568.57**			**23,651.11**	**1,082.54**	**4.80%**	**12.40%**
Wholesale Market Service Rate	1,655,471	0.0036	5,959.70	1,655,471	0.0036	5,959.70	0.00	0.00%	3.12%
Rural Rate Protection Charge	1,655,471	0.0003	496.64	1,655,471	0.0003	496.64	0.00	0.00%	0.26%
Ontario Electricity Support Program Charge	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**6,456.59**			**6,456.59**	**0.00**	**0.00%**	**3.39%**
Debt Retirement Charge (DRC)	1,601,036	0.007	**11,207.25**	1,601,036	0.007	**11,207.25**	**0.00**	**0.00%**	**5.88%**
Total Electricity Charge on Two-Tier RPP (before HST)			**167,703.69**			**168,786.23**	**1,082.54**	**0.65%**	**88.50%**
HST		0.13	21,801.48		0.13	21,942.21	140.73	0.65%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**189,505.17**			**190,728.44**	**1,223.27**	**0.65%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**189,505.17**			**190,728.44**	**1,223.27**	**0.65%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	4,000,000
Peak (kW)	10,000
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	4,136,000
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	4,136,000	0.077	318,472.00	4,136,000	0.077	318,472.00	0.00	0.00%	64.58%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**318,472.00**			**318,472.00**	**0.00**	**0.00%**	**64.58%**
Service Charge	1	1256.56	1,256.56	1	1199.21	1,199.21	-57.35	-4.56%	0.24%
Fixed Deferral/Variance Account Rider	1	11.86	11.86	1	3.82	3.82	-8.04	-67.80%	0.00%
Distribution Volumetric Rate	10,000	1.2052	12,052.00	10,000	1.3103	13,102.59	1,050.59	8.72%	2.66%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10,000	0.3126	3,126.00	10,000	-0.1367	-1,366.70	-4,492.70	-143.72%	-0.28%
Volumetric Global Adjustment Account Rider	4,136,000	-0.0010	-4,136.00	4,136,000	0	0.00	4,136.00	100.00%	0.00%
Sub-Total: Distribution			**12,310.42**			**12,938.91**	**628.49**	**5.11%**	**2.62%**
Retail Transmission Rate – Network Service Rate	10,000	3.3028	33,028.00	10,000	3.4866	34,866.48	1,838.48	5.57%	7.07%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10,000	2.6060	26,060.00	10,000	2.6022	26,021.64	-38.36	-0.15%	5.28%
Sub-Total: Retail Transmission			**59,088.00**			**60,888.12**	**1,800.12**	**3.05%**	**12.35%**
Sub-Total: Delivery			**71,398.42**			**73,827.04**	**2,428.62**	**3.40%**	**14.97%**
Wholesale Market Service Rate	4,136,000	0.0036	14,889.60	4,136,000	0.0036	14,889.60	0.00	0.00%	3.02%
Rural Rate Protection Charge	4,136,000	0.0003	1,240.80	4,136,000	0.0003	1,240.80	0.00	0.00%	0.25%
Ontario Electricity Support Program Charge	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**16,130.65**			**16,130.65**	**0.00**	**0.00%**	**3.27%**
Debt Retirement Charge (DRC)	4,000,000	0.007	**28,000.00**	4,000,000	0.007	**28,000.00**	**0.00**	**0.00%**	**5.68%**
Total Electricity Charge on Two-Tier RPP (before HST)			**434,001.07**			**436,429.69**	**2,428.62**	**0.56%**	**88.50%**
HST		0.13	56,420.14		0.13	56,735.86	315.72	0.56%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**490,421.21**			**493,165.55**	**2,744.34**	**0.56%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**490,421.21**			**493,165.55**	**2,744.34**	**0.56%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	15.18%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**15.18%**
Service Charge	1	35.18	35.18	1	34.76	34.76	-0.42	-1.19%	68.51%
Fixed Deferral/Variance Account Rider	1	0.51	0.51	1	0.00	0.00	-0.51	-99.61%	0.00%
Distribution Volumetric Rate	100	0.0285	2.85	100	0.0284	2.84	-0.01	-0.35%	5.60%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	-0.0001	-0.01	100	0.0000	0.00	0.01	120.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**38.53**			**37.60**	**-0.93**	**-2.40%**	**74.11%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	1.40%
Sub-Total: Distribution			**39.24**			**38.31**	**-0.93**	**-2.36%**	**75.51%**
Retail Transmission Rate – Network Service Rate	109	0.0047	0.51	109	0.0048	0.52	0.01	1.49%	1.03%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0031	0.34	109	0.0038	0.41	0.08	22.42%	0.82%
Sub-Total: Retail Transmission			**0.85**			**0.94**	**0.08**	**9.81%**	**1.84%**
Sub-Total: Delivery			**40.09**			**39.25**	**-0.84**	**-2.10%**	**77.35%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	0.77%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.06%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.49%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**1.33%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**1.38%**
Total Electricity Charge on Two-Tier RPP (before HST)			**49.17**			**48.32**	**-0.84**	**-1.71%**	**95.24%**
HST		0.13	6.39		0.13	6.28	-0.11	-1.71%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**55.56**			**54.61**	**-0.95**	**-1.71%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.93		-0.08	-3.87	0.07	1.71%	-7.62%
Total Amount on Two-Tier RPP			**51.62**			**50.74**	**-0.88**	**-1.71%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	364
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	397
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	364	0.077	28.03	364	0.077	28.03	0.00	0.00%	31.98%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**28.03**			**28.03**	**0.00**	**0.00%**	**31.98%**
Service Charge	1	35.18	35.18	1	34.76	34.76	-0.42	-1.19%	39.66%
Fixed Deferral/Variance Account Rider	1	0.51	0.51	1	0.00	0.00	-0.51	-99.61%	0.00%
Distribution Volumetric Rate	364	0.0285	10.37	364	0.0284	10.34	-0.04	-0.35%	11.80%
Volumetric Deferral/Variance Account Rider (including CBR Class	364	-0.0001	-0.04	364	0.0000	0.01	0.04	120.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**46.03**			**45.11**	**-0.92**	**-2.00%**	**51.47%**
Line Losses on Cost of Power	33	0.0770	2.58	33	0.0770	2.58	0.00	0.00%	2.94%
Sub-Total: Distribution			**48.61**			**47.69**	**-0.92**	**-1.89%**	**54.41%**
Retail Transmission Rate – Network Service Rate	397	0.0047	1.87	397	0.0048	1.90	0.03	1.49%	2.16%
Retail Transmission Rate – Line and Transformation Connection S	397	0.0031	1.23	397	0.0038	1.51	0.28	22.42%	1.72%
Sub-Total: Retail Transmission			**3.10**			**3.40**	**0.30**	**9.81%**	**3.88%**
Sub-Total: Delivery			**51.71**			**51.09**	**-0.62**	**-1.19%**	**58.30%**
Wholesale Market Service Rate	397	0.0036	1.43	397	0.0036	1.43	0.00	0.00%	1.63%
Rural Rate Protection Charge	397	0.0003	0.12	397	0.0003	0.12	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%
Sub-Total: Regulatory			**1.80**			**1.80**	**0.00**	**0.00%**	**2.05%**
Debt Retirement Charge (DRC)	364	0.007	**2.55**	364	0.007	**2.55**	**0.00**	**0.00%**	**2.91%**
Total Electricity Charge on Two-Tier RPP (before HST)			**84.08**			**83.47**	**-0.62**	**-0.73%**	**95.24%**
HST		0.13	10.93		0.13	10.85	-0.08	-0.73%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**95.01**			**94.32**	**-0.70**	**-0.73%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.73		-0.08	-6.68	0.05	0.73%	-7.62%
Total Amount on Two-Tier RPP			**88.29**			**87.64**	**-0.65**	**-0.73%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1092
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	31.87%
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.42%
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**44.29%**
Service Charge	1	35.18	35.18	1	34.76	34.76	-0.42	-1.19%	19.18%
Fixed Deferral/Variance Account Rider	1	0.51	0.51	1	0.00	0.00	-0.51	-99.61%	0.00%
Distribution Volumetric Rate	1,000	0.0285	28.50	1,000	0.0284	28.40	-0.10	-0.35%	15.67%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	-0.0001	-0.10	1,000	0.0000	0.02	0.12	120.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**64.09**			**63.18**	**-0.91**	**-1.42%**	**34.87%**
Line Losses on Cost of Power	92	0.0900	8.28	92	0.0900	8.28	0.00	0.00%	4.57%
Sub-Total: Distribution			**72.37**			**71.46**	**-0.91**	**-1.25%**	**39.44%**
Retail Transmission Rate – Network Service Rate	1,092	0.0047	5.13	1,092	0.0048	5.21	0.08	1.49%	2.87%
Retail Transmission Rate – Line and Transformation Connection S	1,092	0.0031	3.39	1,092	0.0038	4.14	0.76	22.42%	2.29%
Sub-Total: Retail Transmission			**8.52**			**9.35**	**0.84**	**9.81%**	**5.16%**
Sub-Total: Delivery			**80.89**			**80.81**	**-0.07**	**-0.09%**	**44.60%**
Wholesale Market Service Rate	1,092	0.0036	3.93	1,092	0.0036	3.93	0.00	0.00%	2.17%
Rural Rate Protection Charge	1,092	0.0003	0.33	1,092	0.0003	0.33	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%
Sub-Total: Regulatory			**4.51**			**4.51**	**0.00**	**0.00%**	**2.49%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.86%**
Total Electricity Charge on Two-Tier RPP (before HST)			**172.65**			**172.57**	**-0.07**	**-0.04%**	**95.24%**
HST		0.13	22.44		0.13	22.43	-0.01	-0.04%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**195.09**			**195.01**	**-0.08**	**-0.04%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.81		-0.08	-13.81	0.01	0.04%	-7.62%
Total Amount on Two-Tier RPP			**181.28**			**181.20**	**-0.08**	**-0.04%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	20
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	21.84
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	20	0.077	1.54	20	0.077	1.54	0.00	0.00%	18.55%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1.54**			**1.54**	**0.00**	**0.00%**	**18.55%**
Service Charge	1	2.71	2.71	1	3.15	3.15	0.44	16.24%	37.95%
Fixed Deferral/Variance Account Rider	1	0.05	0.05	1	0.01	0.01	-0.04	-88.00%	0.07%
Distribution Volumetric Rate	20	0.1178	2.36	20	0.1199	2.40	0.04	1.78%	28.89%
Volumetric Deferral/Variance Account Rider (including CBR Class	20	0.0009	0.02	20	-0.0001	0.00	-0.02	-106.67%	-0.01%
Sub-Total: Distribution (excluding pass through)			**5.13**			**5.55**	**0.42**	**8.16%**	**66.89%**
Line Losses on Cost of Power	2	0.0770	0.14	2	0.0770	0.14	0.00	0.00%	1.71%
Sub-Total: Distribution			**5.28**			**5.69**	**0.42**	**7.94%**	**68.60%**
Retail Transmission Rate – Network Service Rate	22	0.0045	0.10	22	0.0047	0.10	0.00	4.40%	1.24%
Retail Transmission Rate – Line and Transformation Connection S	22	0.0027	0.06	22	0.0043	0.09	0.03	58.89%	1.13%
Sub-Total: Retail Transmission			**0.16**			**0.20**	**0.04**	**24.83%**	**2.36%**
Sub-Total: Delivery			**5.43**			**5.89**	**0.46**	**8.43%**	**70.96%**
Wholesale Market Service Rate	22	0.0036	0.08	22	0.0036	0.08	0.00	0.00%	0.95%
Rural Rate Protection Charge	22	0.0003	0.01	22	0.0003	0.01	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	22	0.0000	0.00	22	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	3.01%
Sub-Total: Regulatory			**0.34**			**0.34**	**0.00**	**0.00%**	**4.04%**
Debt Retirement Charge (DRC)	20	0.007	**0.14**	20	0.007	**0.14**	**0.00**	**0.00%**	**1.69%**
Total Electricity Charge on Two-Tier RPP (before HST)			**7.45**			**7.91**	**0.46**	**6.15%**	**95.24%**
HST		0.13	0.97		0.13	1.03	0.06	6.15%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**8.42**			**8.93**	**0.52**	**6.15%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-0.60		-0.08	-0.63	-0.04	-6.15%	-7.62%
Total Amount on Two-Tier RPP			**7.82**			**8.30**	**0.48**	**6.15%**	**100.00%**

2018 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	71
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	78
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	71	0.077	5.47	71	0.077	5.47	0.00	0.00%	26.87%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**5.47**			**5.47**	**0.00**	**0.00%**	**26.87%**
Service Charge	1	2.71	2.71	1	3.15	3.15	0.44	16.24%	15.48%
Fixed Deferral/Variance Account Rider	1	0.05	0.05	1	0.01	0.01	-0.04	-88.00%	0.03%
Distribution Volumetric Rate	71	0.1178	8.36	71	0.1199	8.51	0.15	1.78%	41.83%
Volumetric Deferral/Variance Account Rider (including CBR Class	71	0.0009	0.06	71	-0.0001	0.00	-0.07	-106.67%	-0.02%
Sub-Total: Distribution (excluding pass through)			**11.19**			**11.66**	**0.48**	**4.26%**	**57.32%**
Line Losses on Cost of Power	7	0.0770	0.50	7	0.0770	0.50	0.00	0.00%	2.47%
Sub-Total: Distribution			**11.69**			**12.17**	**0.48**	**4.08%**	**59.79%**
Retail Transmission Rate – Network Service Rate	78	0.0045	0.35	78	0.0047	0.36	0.02	4.40%	1.79%
Retail Transmission Rate – Line and Transformation Connection S	78	0.0027	0.21	78	0.0043	0.33	0.12	58.89%	1.63%
Sub-Total: Retail Transmission			**0.56**			**0.70**	**0.14**	**24.83%**	**3.42%**
Sub-Total: Delivery			**12.25**			**12.86**	**0.62**	**5.03%**	**63.22%**
Wholesale Market Service Rate	78	0.0036	0.28	78	0.0036	0.28	0.00	0.00%	1.37%
Rural Rate Protection Charge	78	0.0003	0.02	78	0.0003	0.02	0.00	0.00%	0.11%
Ontario Electricity Support Program Charge	78	0.0000	0.00	78	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.23%
Sub-Total: Regulatory			**0.55**			**0.55**	**0.00**	**0.00%**	**2.71%**
Debt Retirement Charge (DRC)	71	0.007	**0.50**	71	0.007	**0.50**	**0.00**	**0.00%**	**2.44%**
Total Electricity Charge on Two-Tier RPP (before HST)			**18.77**			**19.38**	**0.62**	**3.28%**	**95.24%**
HST		0.13	2.44		0.13	2.52	0.08	3.28%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**21.20**			**21.90**	**0.70**	**3.28%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.50		-0.08	-1.55	-0.05	-3.28%	-7.62%
Total Amount on Two-Tier RPP			**19.70**			**20.35**	**0.65**	**3.28%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	200
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	218.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	200	0.077	15.40	200	0.077	15.40	0.00	0.00%	30.30%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15.40**			**15.40**	**0.00**	**0.00%**	**30.30%**
Service Charge	1	2.71	2.71	1	3.15	3.15	0.44	16.24%	6.20%
Fixed Deferral/Variance Account Rider	1	0.05	0.05	1	0.01	0.01	-0.04	-88.00%	0.01%
Distribution Volumetric Rate	200	0.1178	23.56	200	0.1199	23.98	0.42	1.78%	47.18%
Volumetric Deferral/Variance Account Rider (including CBR Class	200	0.0009	0.18	200	-0.0001	-0.01	-0.19	-106.67%	-0.02%
Sub-Total: Distribution (excluding pass through)			**26.50**			**27.12**	**0.62**	**2.35%**	**53.37%**
Line Losses on Cost of Power	18	0.0770	1.42	18	0.0770	1.42	0.00	0.00%	2.79%
Sub-Total: Distribution			**27.92**			**28.54**	**0.62**	**2.24%**	**56.15%**
Retail Transmission Rate – Network Service Rate	218	0.0045	0.98	218	0.0047	1.03	0.04	4.40%	2.02%
Retail Transmission Rate – Line and Transformation Connection S	218	0.0027	0.59	218	0.0043	0.94	0.35	58.89%	1.84%
Sub-Total: Retail Transmission			**1.57**			**1.96**	**0.39**	**24.83%**	**3.86%**
Sub-Total: Delivery			**29.49**			**30.50**	**1.01**	**3.44%**	**60.02%**
Wholesale Market Service Rate	218	0.0036	0.79	218	0.0036	0.79	0.00	0.00%	1.55%
Rural Rate Protection Charge	218	0.0003	0.07	218	0.0003	0.07	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	218	0.0000	0.00	218	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.49%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	**0.00%**	**2.17%**
Debt Retirement Charge (DRC)	200	0.007	**1.40**	200	0.007	**1.40**	**0.00**	**0.00%**	**2.75%**
Total Electricity Charge on Two-Tier RPP (before HST)			**47.39**			**48.41**	**1.01**	**2.14%**	**95.24%**
HST		0.13	6.16		0.13	6.29	0.13	2.14%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**53.55**			**54.70**	**1.15**	**2.14%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.79		-0.08	-3.87	-0.08	-2.14%	-7.62%
Total Amount on Two-Tier RPP			**49.76**			**50.83**	**1.07**	**2.14%**	**100.00%**

2018 Bill Impacts (Low Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	29.81%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**29.81%**
Service Charge	1	4.25	4.25	1	4.07	4.07	-0.18	-4.24%	15.76%
Fixed Deferral/Variance Account Rider	1	0.08	0.08	1	0.01	0.01	-0.07	-91.25%	0.03%
Distribution Volumetric Rate	100	0.0924	9.24	100	0.0976	9.76	0.52	5.63%	37.78%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	0.0007	0.07	100	0.0000	0.00	-0.07	-101.43%	0.00%
Sub-Total: Distribution (excluding pass through)			**13.64**			**13.84**	**0.20**	**1.44%**	**53.56%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	2.74%
Sub-Total: Distribution			**14.35**			**14.54**	**0.20**	**1.37%**	**56.30%**
Retail Transmission Rate – Network Service Rate	109	0.0045	0.49	109	0.0047	0.51	0.02	4.40%	1.99%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0027	0.29	109	0.0043	0.47	0.17	58.89%	1.81%
Sub-Total: Retail Transmission			**0.79**			**0.98**	**0.20**	**24.83%**	**3.80%**
Sub-Total: Delivery			**15.13**			**15.53**	**0.39**	**2.59%**	**60.10%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	1.52%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.97%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**2.62%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**2.71%**
Total Electricity Charge on Two-Tier RPP (before HST)			**24.21**			**24.60**	**0.39**	**1.62%**	**95.24%**
HST		0.13	3.15		0.13	3.20	0.05	1.62%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**27.36**			**27.80**	**0.44**	**1.62%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.94		-0.08	-1.97	-0.03	-1.62%	-7.62%
Total Amount on Two-Tier RPP			**25.42**			**25.83**	**0.41**	**1.62%**	**100.00%**

2018 Bill Impacts (Typical Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	517
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	565
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	517	0.077	39.81	517	0.077	39.81	0.00	0.00%	34.74%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**39.81**			**39.81**	**0.00**	**0.00%**	**34.74%**
Service Charge	1	4.25	4.25	1	4.07	4.07	-0.18	-4.24%	3.55%
Fixed Deferral/Variance Account Rider	1	0.08	0.08	1	0.01	0.01	-0.07	-91.25%	0.01%
Distribution Volumetric Rate	517	0.0924	47.77	517	0.0976	50.46	2.69	5.63%	44.03%
Volumetric Deferral/Variance Account Rider (including CBR Class	517	0.0007	0.36	517	0.0000	-0.01	-0.37	-101.43%	0.00%
Sub-Total: Distribution (excluding pass through)			**52.46**			**54.53**	**2.07**	**3.94%**	**47.58%**
Line Losses on Cost of Power	48	0.0770	3.66	48	0.0770	3.66	0.00	0.00%	3.20%
Sub-Total: Distribution			**56.13**			**58.19**	**2.07**	**3.69%**	**50.78%**
Retail Transmission Rate – Network Service Rate	565	0.0045	2.54	565	0.0047	2.65	0.11	4.40%	2.31%
Retail Transmission Rate – Line and Transformation Connection S	565	0.0027	1.52	565	0.0043	2.42	0.90	58.89%	2.11%
Sub-Total: Retail Transmission			**4.06**			**5.07**	**1.01**	**24.83%**	**4.43%**
Sub-Total: Delivery			**60.19**			**63.27**	**3.08**	**5.11%**	**55.21%**
Wholesale Market Service Rate	565	0.0036	2.03	565	0.0036	2.03	0.00	0.00%	1.77%
Rural Rate Protection Charge	565	0.0003	0.17	565	0.0003	0.17	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	565	0.0000	0.00	565	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.22%
Sub-Total: Regulatory			**2.45**			**2.45**	**0.00**	**0.00%**	**2.14%**
Debt Retirement Charge (DRC)	517	0.007	**3.62**	517	0.007	**3.62**	**0.00**	**0.00%**	**3.16%**
Total Electricity Charge on Two-Tier RPP (before HST)			**106.07**			**109.15**	**3.08**	**2.90%**	**95.24%**
HST		0.13	13.79		0.13	14.19	0.40	2.90%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**119.86**			**123.34**	**3.48**	**2.90%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.49		-0.08	-8.73	-0.25	-2.90%	-7.62%
Total Amount on Two-Tier RPP			**111.37**			**114.60**	**3.23**	**2.90%**	**100.00%**

2018 Bill Impacts (High Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2184
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.84%
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	25.01%
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**37.84%**
Service Charge	1	4.25	4.25	1	4.07	4.07	-0.18	-4.24%	0.90%
Fixed Deferral/Variance Account Rider	1	0.08	0.08	1	0.01	0.01	-0.07	-91.25%	0.00%
Distribution Volumetric Rate	2,000	0.0924	184.80	2,000	0.0976	195.20	10.40	5.63%	43.39%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0007	1.40	2,000	0.0000	-0.02	-1.42	-101.43%	0.00%
Sub-Total: Distribution (excluding pass through)			**190.53**			**199.26**	**8.73**	**4.58%**	**44.29%**
Line Losses on Cost of Power	184	0.0900	16.56	184	0.0900	16.56	0.00	0.00%	3.68%
Sub-Total: Distribution			**207.09**			**215.82**	**8.73**	**4.21%**	**47.97%**
Retail Transmission Rate – Network Service Rate	2,184	0.0045	9.83	2,184	0.0047	10.26	0.43	4.40%	2.28%
Retail Transmission Rate – Line and Transformation Connection S	2,184	0.0027	5.90	2,184	0.0043	9.37	3.47	58.89%	2.08%
Sub-Total: Retail Transmission			**15.72**			**19.63**	**3.90**	**24.83%**	**4.36%**
Sub-Total: Delivery			**222.81**			**235.45**	**12.63**	**5.67%**	**52.33%**
Wholesale Market Service Rate	2,184	0.0036	7.86	2,184	0.0036	7.86	0.00	0.00%	1.75%
Rural Rate Protection Charge	2,184	0.0003	0.66	2,184	0.0003	0.66	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	2,184	0.0000	0.00	2,184	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%
Sub-Total: Regulatory			**8.77**			**8.77**	**0.00**	**0.00%**	**1.95%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.11%**
Total Electricity Charge on Two-Tier RPP (before HST)			**415.83**			**428.46**	**12.63**	**3.04%**	**95.24%**
HST		0.13	54.06		0.13	55.70	1.64	3.04%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**469.89**			**484.16**	**14.27**	**3.04%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.27		-0.08	-34.28	-1.01	-3.04%	-7.62%
Total Amount on Two-Tier RPP			**436.62**			**449.89**	**13.26**	**3.04%**	**100.00%**

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2018 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$72.04	$2.44	7.99%	$2.56	3.55%
	Typical	750		$119.87	$1.20	3.56%	$1.25	1.05%
	Average	755		$120.47	$1.18	3.51%	$1.24	1.03%
	High	1,400		$197.59	($0.82)	-2.12%	($0.86)	-0.44%
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%
Seasonal	Low	50		$52.39	$4.19	9.62%	$4.39	8.39%
	Average	352		$105.24	$1.98	3.21%	$2.08	1.98%
	High	1,000		$218.66	($2.75)	-2.73%	($2.89)	-1.32%
GSe	Low	1,000		$212.09	$3.04	3.44%	$3.19	1.51%
	Typical	2,000		$392.04	$5.44	3.69%	$5.71	1.46%
	Average	1,982		$388.80	$5.40	3.69%	$5.67	1.46%
	High	15,000		$2,731.44	$36.64	4.01%	$38.47	1.41%
UGe	Low	1,000		$171.22	$1.79	3.46%	$1.88	1.10%
	Typical	2,000		$316.26	$2.99	3.76%	$3.14	0.99%
	Average	2,759		$426.34	$3.90	3.87%	$4.10	0.96%
	High	15,000		$2,201.80	$18.59	4.21%	$19.52	0.89%
GSd	Low	15,000	60	$3,026.88	$38.78	3.50%	$43.82	1.45%
	Average	36,104	124	$6,667.11	$78.36	3.59%	$88.55	1.33%
	High	175,000	500	$29,617.60	$310.92	3.66%	$351.34	1.19%
UGd	Low	15,000	60	$2,592.60	$23.44	3.45%	$26.48	1.02%
	Average	50,525	135	$7,433.58	$50.24	3.58%	$56.77	0.76%
	High	175,000	500	$25,963.00	$180.65	3.67%	$204.13	0.79%
St Lgt	Low	100		$25.83	$0.48	3.47%	$0.50	1.95%
	Average	517		$114.60	$1.94	3.56%	$2.04	1.78%
	High	2,000		$449.89	$7.13	3.58%	$7.49	1.66%
Sen Lgt	Low	20		$8.30	$0.38	6.92%	$0.40	4.86%
	Average	71		$20.35	$0.80	6.88%	$0.84	4.14%
	High	200		$50.83	$1.86	6.86%	$1.95	3.84%
USL	Low	100		$50.74	$0.80	2.13%	$0.84	1.66%
	Average	364		$87.64	$0.98	2.18%	$1.03	1.18%
	High	1,000		$181.20	$1.43	2.26%	$1.50	0.83%
DGen	Low	300	10	$339.45	$33.91	13.02%	$38.32	11.29%
	Average	1,328	13	$473.09	$44.08	15.75%	$49.81	10.53%
	High	5,000	100	$1,606.67	$339.10	40.39%	$383.18	23.85%
ST	Low	200,000	500	$25,950.00	$52.55	2.94%	$59.39	0.23%
	Average	1,601,036	3,091	$190,728.44	$196.59	4.07%	$222.15	0.12%
	High	4,000,000	10,000	$493,165.55	$580.66	4.49%	$656.15	0.13%

2019 Bill Impacts (Low Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	370
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	37.12%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**37.12%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		19.82%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.58%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		11.15%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**39.61%**	**38.55%**
Service Charge	1	27.71	27.71	1	31.23	31.23	3.52	12.70%	43.02%	41.86%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	350	0.0078	2.73	350	0.0047	1.65	-1.09	-39.74%	2.27%	2.21%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	350	0.0000	0.01	350	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**30.46**			**32.89**	**2.44**	**7.99%**	**45.31%**	**44.09%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.09%	1.06%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	2.12%	2.06%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.26%	2.20%
Sub-Total: Distribution (based on two-tier RPP prices)			**32.78**			**35.22**	**2.44**	**7.43%**	**48.51%**	**47.21%**
Sub-Total: Distribution (based on TOU prices)			**32.89**			**35.32**	**2.44**	**7.40%**	**48.65%**	**47.35%**
Retail Transmission Rate – Network Service Rate	370	0.0078	2.90	370	0.0078	2.90	0.00	0.00%	3.99%	3.88%
Retail Transmission Rate – Line and Transformation Connection Service Rate	370	0.0064	2.38	370	0.0064	2.38	0.00	0.00%	3.28%	3.19%
Sub-Total: Retail Transmission			**5.28**			**5.28**	**0.00**	**0.00%**	**7.27%**	**7.07%**
Sub-Total: Delivery (based on two-tier RPP prices)			**38.06**			**40.50**	**2.44**	**6.40%**	**55.78%**	**54.28%**
Sub-Total: Delivery (based on TOU prices)			**38.16**			**40.60**	**2.44**	**6.38%**	**55.92%**	**54.42%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.83%	1.79%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.34%	0.34%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.33%**	**2.27%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**66.70**			**69.14**	**2.44**	**3.65%**	**95.24%**	
HST		0.13	8.67		0.13	8.99	0.32	3.65%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**75.38**			**78.13**	**2.75**	**3.65%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.34		-0.08	-5.53	-0.19	-3.65%	-7.62%	
Total Amount on Two-Tier RPP			**70.04**			**72.60**	**2.56**	**3.65%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**68.61**			**71.05**	**2.44**	**3.55%**		**95.24%**
HST		0.13	8.92		0.13	9.24	0.32	3.55%		12.38%
Total Electricity Charge on TOU (including HST)			**77.53**			**80.28**	**2.75**	**3.55%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.49		-0.08	-5.68	-0.19	-3.55%		-7.62%
Total Amount on TOU			**72.04**			**74.60**	**2.56**	**3.55%**		**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	793
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.67%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.30%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**49.97%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		26.16%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		10.00%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.71%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**51.58%**	**50.87%**
Service Charge	1	27.71	27.71	1	31.23	31.23	3.52	12.70%	26.14%	25.78%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	750	0.0078	5.85	750	0.0047	3.53	-2.33	-39.74%	2.95%	2.91%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**33.59**			**34.78**	**1.20**	**3.56%**	**29.12%**	**28.72%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.66%	0.65%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.22%	3.18%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	2.94%	2.90%
Sub-Total: Distribution (based on two-tier RPP prices)			**38.23**			**39.42**	**1.20**	**3.13%**	**33.00%**	**32.55%**
Sub-Total: Distribution (based on TOU prices)			**37.89**			**39.09**	**1.20**	**3.15%**	**32.72%**	**32.27%**
Retail Transmission Rate – Network Service Rate	793	0.0078	6.21	793	0.0078	6.21	0.00	0.00%	5.19%	5.12%
Retail Transmission Rate – Line and Transformation Connection Service Rate	793	0.0064	5.10	793	0.0064	5.10	0.00	0.00%	4.27%	4.21%
Sub-Total: Retail Transmission			**11.31**			**11.31**	**0.00**	**0.00%**	**9.47%**	**9.34%**
Sub-Total: Delivery (based on two-tier RPP prices)			**49.54**			**50.73**	**1.19**	**2.41%**	**42.47%**	**41.88%**
Sub-Total: Delivery (based on TOU prices)			**49.20**			**50.40**	**1.20**	**2.43%**	**42.19%**	**41.61%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.39%	2.36%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.80%**	**2.76%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**112.58**			**113.77**	**1.19**	**1.06%**	**95.24%**	
HST		0.13	14.64		0.13	14.79	0.16	1.06%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**127.21**			**128.56**	**1.35**	**1.06%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.01		-0.08	-9.10	-0.10	-1.06%	-7.62%	
Total Amount on Two-Tier RPP			**118.21**			**119.46**	**1.25**	**1.06%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**114.16**			**115.36**	**1.20**	**1.05%**		**95.24%**
HST		0.13	14.84		0.13	15.00	0.16	1.05%		12.38%
Total Electricity Charge on TOU (including HST)			**129.00**			**130.35**	**1.35**	**1.05%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.13		-0.08	-9.23	-0.10	-1.05%		-7.62%
Total Amount on TOU			**119.87**			**121.13**	**1.25**	**1.05%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	755
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	798
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.47%	
Energy Second Tier (kWh)	155	0.090	13.95	155	0.090	13.95	0.00	0.00%	11.62%	
Sub-Total: Energy (RPP)			**60.15**			**60.15**	**0.00**	**0.00%**	**50.09%**	
TOU-Off Peak	491	0.065	31.90	491	0.065	31.90	0.00	0.00%		26.21%
TOU-Mid Peak	128	0.095	12.19	128	0.095	12.19	0.00	0.00%		10.02%
TOU-On Peak	136	0.132	17.94	136	0.132	17.94	0.00	0.00%		14.74%
Sub-Total: Energy (TOU)			**62.03**			**62.03**	0.00	0.00%	**51.65%**	**50.97%**
Service Charge	1	27.71	27.71	1	31.23	31.23	3.52	12.70%	26.01%	25.66%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	755	0.0078	5.89	755	0.0047	3.55	-2.34	-39.74%	2.95%	2.92%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	755	0.0000	0.02	755	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**33.63**			**34.81**	**1.18**	**3.51%**	**28.99%**	**28.60%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.66%	0.65%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.87	43	0.0900	3.87	0.00	0.00%	3.23%	3.18%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	43	0.0822	3.54	0.00	0.00%	2.94%	2.91%
Sub-Total: Distribution (based on two-tier RPP prices)			**38.29**			**39.47**	**1.18**	**3.08%**	**32.87%**	**32.43%**
Sub-Total: Distribution (based on TOU prices)			**37.95**			**39.13**	**1.18**	**3.11%**	**32.59%**	**32.15%**
Retail Transmission Rate – Network Service Rate	798	0.0078	6.25	798	0.0078	6.25	0.00	0.00%	5.20%	5.13%
Retail Transmission Rate – Line and Transformation Connection Service Rate	798	0.0064	5.14	798	0.0064	5.14	0.00	0.00%	4.28%	4.22%
Sub-Total: Retail Transmission			**11.38**			**11.38**	**0.00**	**0.00%**	**9.48%**	**9.35%**
Sub-Total: Delivery (based on two-tier RPP prices)			**49.68**			**50.86**	**1.18**	**2.37%**	**42.35%**	**41.79%**
Sub-Total: Delivery (based on TOU prices)			**49.34**			**50.52**	**1.18**	**2.39%**	**42.07%**	**41.51%**
Wholesale Market Service Rate	798	0.0036	2.87	798	0.0036	2.87	0.00	0.00%	2.39%	2.36%
Rural Rate Protection Charge	798	0.0003	0.24	798	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	798	0.0000	0.00	798	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**3.36**			**3.36**	**0.00**	**0.00%**	**2.80%**	**2.76%**
Debt Retirement Charge (DRC)	755	0.000	**0.00**	755	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**113.19**			**114.37**	**1.18**	**1.04%**	**95.24%**	
HST		0.13	14.71		0.13	14.87	0.15	1.04%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**127.90**			**129.24**	**1.33**	**1.04%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.06		-0.08	-9.15	-0.09	-1.04%	-7.62%	
Total Amount on Two-Tier RPP			**118.85**			**120.09**	**1.24**	**1.04%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**114.73**			**115.91**	**1.18**	**1.03%**		**95.24%**
HST		0.13	14.92		0.13	15.07	0.15	1.03%		12.38%
Total Electricity Charge on TOU (including HST)			**129.65**			**130.98**	**1.33**	**1.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.18		-0.08	-9.27	-0.09	-1.03%		-7.62%
Total Amount on TOU			**120.47**			**121.71**	**1.24**	**1.03%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1480
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.02%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	35.87%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**58.89%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		30.07%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.49%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		16.91%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**57.31%**	**58.47%**
Service Charge	1	27.71	27.71	1	31.23	31.23	3.52	12.70%	15.56%	15.87%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0078	10.92	1,400	0.0047	6.58	-4.34	-39.74%	3.28%	3.34%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,400	0.0000	0.04	1,400	0.0000	0.04	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**38.68**			**37.86**	**-0.82**	**-2.12%**	**18.86%**	**19.24%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.39%	0.40%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.58%	3.65%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.27%	3.33%
Sub-Total: Distribution (based on two-tier RPP prices)			**46.65**			**45.83**	**-0.82**	**-1.76%**	**22.83%**	**23.30%**
Sub-Total: Distribution (based on TOU prices)			**46.03**			**45.21**	**-0.82**	**-1.78%**	**22.52%**	**22.98%**
Retail Transmission Rate – Network Service Rate	1,480	0.0078	11.58	1,480	0.0078	11.58	0.00	0.00%	5.77%	5.89%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,480	0.0064	9.53	1,480	0.0064	9.53	0.00	0.00%	4.75%	4.84%
Sub-Total: Retail Transmission			**21.11**			**21.11**	**0.00**	**0.00%**	**10.52%**	**10.73%**
Sub-Total: Delivery (based on two-tier RPP prices)			**67.76**			**66.94**	**-0.82**	**-1.21%**	**33.35%**	**34.03%**
Sub-Total: Delivery (based on TOU prices)			**67.14**			**66.32**	**-0.82**	**-1.22%**	**33.04%**	**33.71%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.65%	2.71%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**3.00%**	**3.06%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**191.98**			**191.16**	**-0.82**	**-0.43%**	**95.24%**	
HST		0.13	24.96		0.13	24.85	-0.11	-0.43%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**216.94**			**216.01**	**-0.93**	**-0.43%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.36		-0.08	-15.29	0.07	0.43%	-7.62%	
Total Amount on Two-Tier RPP			**201.58**			**200.72**	**-0.86**	**-0.43%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**188.18**			**187.36**	**-0.82**	**-0.44%**		**95.24%**
HST		0.13	24.46		0.13	24.36	-0.11	-0.44%		12.38%
Total Electricity Charge on TOU (including HST)			**212.64**			**211.72**	**-0.93**	**-0.44%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.05		-0.08	-14.99	0.07	0.44%		-7.62%
Total Amount on TOU			**197.59**			**196.73**	**-0.86**	**-0.44%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	430
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	37.61%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**37.61%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		20.06%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.67%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		11.28%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**40.13%**	**39.02%**
Service Charge	1	37.79	36.43	1	42.19	36.43	0.00	0.00%	44.48%	43.25%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0218	0.00	400	0.0193	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	400	0.0000	0.01	400	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.44**			**36.44**	**0.00**	**0.00%**	**44.50%**	**43.26%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.96%	0.94%
Line Losses on Cost of Power (based on two-tier RPP prices)	30	0.0770	2.34	30	0.0770	2.34	0.00	0.00%	2.86%	2.78%
Line Losses on Cost of Power (based on TOU prices)	30	0.0822	2.50	30	0.0822	2.50	0.00	0.00%	3.05%	2.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.57**			**39.57**	**0.00**	**0.00%**	**48.32%**	**46.98%**
Sub-Total: Distribution (based on TOU prices)			**39.73**			**39.73**	**0.00**	**0.00%**	**48.51%**	**47.17%**
Retail Transmission Rate – Network Service Rate	430	0.0072	3.10	430	0.0072	3.10	0.00	0.00%	3.79%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	430	0.0060	2.60	430	0.0060	2.60	0.00	0.00%	3.17%	3.08%
Sub-Total: Retail Transmission			**5.70**			**5.70**	**0.00**	**0.00%**	**6.96%**	**6.76%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.27**			**45.27**	**0.00**	**0.00%**	**55.28%**	**53.75%**
Sub-Total: Delivery (based on TOU prices)			**45.43**			**45.43**	**0.00**	**0.00%**	**55.47%**	**53.93%**
Wholesale Market Service Rate	430	0.0036	1.55	430	0.0036	1.55	0.00	0.00%	1.89%	1.84%
Rural Rate Protection Charge	430	0.0003	0.13	430	0.0003	0.13	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	430	0.0000	0.00	430	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%	0.30%
Sub-Total: Regulatory			**1.93**			**1.93**	**0.00**	**0.00%**	**2.35%**	**2.29%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**78.00**			**78.00**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.14		0.13	10.14	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**88.14**			**88.14**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.24		-0.08	-6.24	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**81.90**			**81.90**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**80.22**			**80.22**	**0.00**	**0.00%**		**95.24%**
HST		0.13	10.43		0.13	10.43	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**90.65**			**90.65**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.42		-0.08	-6.42	0.00	0.00%		-7.62%
Total Amount on TOU			**84.23**			**84.23**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	807
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.88%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.07%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.95%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.66%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.81%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.43%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.53%**	**49.89%**
Service Charge	1	37.79	36.43	1	42.19	36.43	0.00	0.00%	29.87%	29.50%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0218	0.00	750	0.0193	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**29.89%**	**29.51%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	4.21%	4.15%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	3.84%	3.79%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.37**			**42.37**	**0.00**	**0.00%**	**34.74%**	**34.31%**
Sub-Total: Distribution (based on TOU prices)			**41.92**			**41.92**	**0.00**	**0.00%**	**34.37%**	**33.94%**
Retail Transmission Rate – Network Service Rate	807	0.0072	5.82	807	0.0072	5.82	0.00	0.00%	4.77%	4.71%
Retail Transmission Rate – Line and Transformation Connection Service Rate	807	0.0060	4.87	807	0.0060	4.87	0.00	0.00%	3.99%	3.94%
Sub-Total: Retail Transmission			**10.68**			**10.68**	**0.00**	**0.00%**	**8.76%**	**8.65%**
Sub-Total: Delivery (based on two-tier RPP prices)			**53.05**			**53.05**	**0.00**	**0.00%**	**43.50%**	**42.96%**
Sub-Total: Delivery (based on TOU prices)			**52.61**			**52.61**	**0.00**	**0.00%**	**43.13%**	**42.59%**
Wholesale Market Service Rate	807	0.0036	2.91	807	0.0036	2.91	0.00	0.00%	2.38%	2.35%
Rural Rate Protection Charge	807	0.0003	0.24	807	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	807	0.0000	0.00	807	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.40**			**3.40**	**0.00**	**0.00%**	**2.79%**	**2.75%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**116.15**			**116.15**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.10		0.13	15.10	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**131.25**			**131.25**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.29		-0.08	-9.29	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**121.96**			**121.96**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.62**			**117.62**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.29		0.13	15.29	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**132.91**			**132.91**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.41	0.00	0.00%		-7.62%
Total Amount on TOU			**123.50**			**123.50**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	920
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	990
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	32.41%	
Energy Second Tier (kWh)	320	0.090	28.80	320	0.090	28.80	0.00	0.00%	20.20%	
Sub-Total: Energy (RPP)			**75.00**			**75.00**	**0.00**	**0.00%**	**52.62%**	
TOU-Off Peak	598	0.065	38.87	598	0.065	38.87	0.00	0.00%		27.26%
TOU-Mid Peak	156	0.095	14.86	156	0.095	14.86	0.00	0.00%		10.42%
TOU-On Peak	166	0.132	21.86	166	0.132	21.86	0.00	0.00%		15.33%
Sub-Total: Energy (TOU)			**75.59**			**75.59**	0.00	0.00%	**53.03%**	**53.01%**
Service Charge	1	37.79	36.43	1	42.19	36.43	0.00	0.00%	25.56%	25.55%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	920	0.0218	0.00	920	0.0193	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	920	0.0000	0.02	920	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**25.57%**	**25.57%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.55%	0.55%
Line Losses on Cost of Power (based on two-tier RPP prices)	70	0.0900	6.29	70	0.0900	6.29	0.00	0.00%	4.41%	4.41%
Line Losses on Cost of Power (based on TOU prices)	70	0.0822	5.74	70	0.0822	5.74	0.00	0.00%	4.03%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.54**			**43.54**	**0.00**	**0.00%**	**30.54%**	**30.53%**
Sub-Total: Distribution (based on TOU prices)			**42.99**			**42.99**	**0.00**	**0.00%**	**30.16%**	**30.15%**
Retail Transmission Rate – Network Service Rate	990	0.0072	7.13	990	0.0072	7.13	0.00	0.00%	5.01%	5.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	990	0.0060	5.97	990	0.0060	5.97	0.00	0.00%	4.19%	4.19%
Sub-Total: Retail Transmission			**13.11**			**13.11**	**0.00**	**0.00%**	**9.19%**	**9.19%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.64**			**56.64**	**0.00**	**0.00%**	**39.74%**	**39.73%**
Sub-Total: Delivery (based on TOU prices)			**56.09**			**56.09**	**0.00**	**0.00%**	**39.35%**	**39.34%**
Wholesale Market Service Rate	990	0.0036	3.56	990	0.0036	3.56	0.00	0.00%	2.50%	2.50%
Rural Rate Protection Charge	990	0.0003	0.30	990	0.0003	0.30	0.00	0.00%	0.21%	0.21%
Ontario Electricity Support Program Charge	990	0.0000	0.00	990	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**4.11**			**4.11**	**0.00**	**0.00%**	**2.88%**	**2.88%**
Debt Retirement Charge (DRC)	920	0.000	**0.00**	920	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**135.75**			**135.75**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	17.65		0.13	17.65	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**153.40**			**153.40**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.86	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**142.54**			**142.54**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**135.79**			**135.79**	**0.00**	**0.00%**		**95.24%**
HST		0.13	17.65		0.13	17.65	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**153.44**			**153.44**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.86	0.00	0.00%		-7.62%
Total Amount on TOU			**142.58**			**142.58**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1937
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.55%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.36%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.91%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.51%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		12.05%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.72%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**59.37%**	**61.28%**
Service Charge	1	37.79	36.43	1	42.19	36.43	0.00	0.00%	14.63%	15.10%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0218	0.00	1,800	0.0193	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,800	0.0000	0.04	1,800	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.47**			**36.47**	**0.00**	**0.00%**	**14.64%**	**15.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.32%	0.33%
Line Losses on Cost of Power (based on two-tier RPP prices)	137	0.0900	12.31	137	0.0900	12.31	0.00	0.00%	4.94%	5.10%
Line Losses on Cost of Power (based on TOU prices)	137	0.0822	11.24	137	0.0822	11.24	0.00	0.00%	4.51%	4.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.57**			**49.57**	**0.00**	**0.00%**	**19.90%**	**20.54%**
Sub-Total: Distribution (based on TOU prices)			**48.50**			**48.50**	**0.00**	**0.00%**	**19.47%**	**20.10%**
Retail Transmission Rate – Network Service Rate	1,937	0.0072	13.96	1,937	0.0072	13.96	0.00	0.00%	5.60%	5.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,937	0.0060	11.68	1,937	0.0060	11.68	0.00	0.00%	4.69%	4.84%
Sub-Total: Retail Transmission			**25.64**			**25.64**	**0.00**	**0.00%**	**10.29%**	**10.63%**
Sub-Total: Delivery (based on two-tier RPP prices)			**75.21**			**75.21**	**0.00**	**0.00%**	**30.20%**	**31.17%**
Sub-Total: Delivery (based on TOU prices)			**74.14**			**74.14**	**0.00**	**0.00%**	**29.77%**	**30.72%**
Wholesale Market Service Rate	1,937	0.0036	6.97	1,937	0.0036	6.97	0.00	0.00%	2.80%	2.89%
Rural Rate Protection Charge	1,937	0.0003	0.58	1,937	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,937	0.0000	0.00	1,937	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.80**			**7.80**	**0.00**	**0.00%**	**3.13%**	**3.23%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**237.22**			**237.22**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	30.84		0.13	30.84	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**268.06**			**268.06**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.98		-0.08	-18.98	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**249.08**			**249.08**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**229.83**			**229.83**	**0.00**	**0.00%**		**95.24%**
HST		0.13	29.88		0.13	29.88	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**259.71**			**259.71**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.39		-0.08	-18.39	0.00	0.00%		-7.62%
Total Amount on TOU			**241.32**			**241.32**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	450
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	497
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	450	0.077	34.65	450	0.077	34.65	0.00	0.00%	39.36%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**34.65**			**34.65**	**0.00**	**0.00%**	**39.36%**	
TOU-Off Peak	293	0.065	19.01	293	0.065	19.01	0.00	0.00%		20.96%
TOU-Mid Peak	77	0.095	7.27	77	0.095	7.27	0.00	0.00%		8.01%
TOU-On Peak	81	0.132	10.69	81	0.132	10.69	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**36.97**			**36.97**	0.00	0.00%	**42.00%**	**40.75%**
Service Charge (RRRP credit applied)	1	25.02	25.02	1	34.09	34.09	9.07	36.25%	38.73%	37.58%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	450	0.0359	11.41	450	0.0321	2.34	-9.07	-79.49%	2.66%	2.58%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	450	0.0000	0.00	450	0.0000	0.00	0.00	0.00%	0.01%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.41**			**36.41**	**0.00**	**0.00%**	**41.37%**	**40.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.90%	0.87%
Line Losses on Cost of Power (based on two-tier RPP prices)	47	0.0770	3.64	47	0.0770	3.64	0.00	0.00%	4.13%	4.01%
Line Losses on Cost of Power (based on TOU prices)	47	0.0822	3.88	47	0.0822	3.88	0.00	0.00%	4.41%	4.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.84**			**40.84**	**0.00**	**0.00%**	**46.40%**	**45.02%**
Sub-Total: Distribution (based on TOU prices)			**41.09**			**41.09**	**0.00**	**0.00%**	**46.68%**	**45.29%**
Retail Transmission Rate – Network Service Rate	497	0.0067	3.35	497	0.0067	3.35	0.00	0.00%	3.81%	3.69%
Retail Transmission Rate – Line and Transformation Connection Service Rate	497	0.0056	2.80	497	0.0056	2.80	0.00	0.00%	3.18%	3.09%
Sub-Total: Retail Transmission			**6.15**			**6.15**	**0.00**	**0.00%**	**6.99%**	**6.78%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.99**			**46.99**	**0.00**	**0.00%**	**53.39%**	**51.80%**
Sub-Total: Delivery (based on TOU prices)			**47.24**			**47.24**	**0.00**	**0.00%**	**53.66%**	**52.07%**
Wholesale Market Service Rate	497	0.0036	1.79	497	0.0036	1.79	0.00	0.00%	2.03%	1.97%
Rural Rate Protection Charge	497	0.0003	0.15	497	0.0003	0.15	0.00	0.00%	0.17%	0.16%
Ontario Electricity Support Program Charge	497	0.0000	0.00	497	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%	0.28%
Sub-Total: Regulatory			**2.19**			**2.19**	**0.00**	**0.00%**	**2.49%**	**2.41%**
Debt Retirement Charge (DRC)	450	0.000	**0.00**	450	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**83.83**			**83.83**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.90		0.13	10.90	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**94.73**			**94.73**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.71		-0.08	-6.71	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**88.02**			**88.02**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**86.40**			**86.40**	**0.00**	**0.00%**		**95.24%**
HST		0.13	11.23		0.13	11.23	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**97.63**			**97.63**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.91		-0.08	-6.91	0.00	0.00%		-7.62%
Total Amount on TOU			**90.72**			**90.72**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	829
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.37%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.92%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.30%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.35%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.69%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.26%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.85%**	**49.30%**
Service Charge (RRRP credit applied)	1	25.02	25.02	1	34.09	34.09	9.07	36.25%	27.58%	27.28%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	750	0.0359	11.41	750	0.0321	2.34	-9.07	-79.49%	1.89%	1.87%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.01	750	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**29.46%**	**29.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.63%
Line Losses on Cost of Power (based on two-tier RPP prices)	79	0.0900	7.09	79	0.0900	7.09	0.00	0.00%	5.73%	5.67%
Line Losses on Cost of Power (based on TOU prices)	79	0.0822	6.47	79	0.0822	6.47	0.00	0.00%	5.23%	5.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.29**			**44.29**	**0.00**	**0.00%**	**35.83%**	**35.44%**
Sub-Total: Distribution (based on TOU prices)			**43.68**			**43.68**	**0.00**	**0.00%**	**35.33%**	**34.95%**
Retail Transmission Rate – Network Service Rate	829	0.0067	5.59	829	0.0067	5.59	0.00	0.00%	4.52%	4.47%
Retail Transmission Rate – Line and Transformation Connection Service Rate	829	0.0056	4.67	829	0.0056	4.67	0.00	0.00%	3.77%	3.73%
Sub-Total: Retail Transmission			**10.25**			**10.25**	**0.00**	**0.00%**	**8.29%**	**8.20%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.55**			**54.55**	**0.00**	**0.00%**	**44.13%**	**43.64%**
Sub-Total: Delivery (based on TOU prices)			**53.93**			**53.93**	**0.00**	**0.00%**	**43.63%**	**43.15%**
Wholesale Market Service Rate	829	0.0036	2.98	829	0.0036	2.98	0.00	0.00%	2.41%	2.39%
Rural Rate Protection Charge	829	0.0003	0.25	829	0.0003	0.25	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	829	0.0000	0.00	829	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.48**			**3.48**	**0.00**	**0.00%**	**2.82%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**117.73**			**117.73**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.30		0.13	15.30	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**133.03**			**133.03**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.42		-0.08	-9.42	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**123.61**			**123.61**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**119.03**			**119.03**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.47		0.13	15.47	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**134.50**			**134.50**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.52		-0.08	-9.52	0.00	0.00%		-7.62%
Total Amount on TOU			**124.98**			**124.98**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	1152
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1273
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	26.68%	
Energy Second Tier (kWh)	552	0.090	49.68	552	0.090	49.68	0.00	0.00%	28.69%	
Sub-Total: Energy (RPP)			**95.88**			**95.88**	**0.00**	**0.00%**	**55.36%**	
TOU-Off Peak	749	0.065	48.67	749	0.065	48.67	0.00	0.00%		28.48%
TOU-Mid Peak	196	0.095	18.60	196	0.095	18.60	0.00	0.00%		10.89%
TOU-On Peak	207	0.132	27.37	207	0.132	27.37	0.00	0.00%		16.02%
Sub-Total: Energy (TOU)			**94.65**			**94.65**	0.00	0.00%	**54.65%**	**55.38%**
Service Charge (RRRP credit applied)	1	25.02	25.02	1	34.09	34.09	9.07	36.25%	19.68%	19.95%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	1,152	0.0359	11.41	1,152	0.0321	2.34	-9.07	-79.49%	1.35%	1.37%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,152	0.0000	0.01	1,152	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**21.03%**	**21.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	121	0.0900	10.89	121	0.0900	10.89	0.00	0.00%	6.29%	6.37%
Line Losses on Cost of Power (based on TOU prices)	121	0.0822	9.94	121	0.0822	9.94	0.00	0.00%	5.74%	5.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**48.10**			**48.10**	**0.00**	**0.00%**	**27.77%**	**28.14%**
Sub-Total: Distribution (based on TOU prices)			**47.15**			**47.15**	**0.00**	**0.00%**	**27.22%**	**27.59%**
Retail Transmission Rate – Network Service Rate	1,273	0.0067	8.58	1,273	0.0067	8.58	0.00	0.00%	4.95%	5.02%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,273	0.0056	7.17	1,273	0.0056	7.17	0.00	0.00%	4.14%	4.19%
Sub-Total: Retail Transmission			**15.75**			**15.75**	**0.00**	**0.00%**	**9.09%**	**9.21%**
Sub-Total: Delivery (based on two-tier RPP prices)			**63.84**			**63.84**	**0.00**	**0.00%**	**36.86%**	**37.36%**
Sub-Total: Delivery (based on TOU prices)			**62.90**			**62.90**	**0.00**	**0.00%**	**36.32%**	**36.80%**
Wholesale Market Service Rate	1,273	0.0036	4.58	1,273	0.0036	4.58	0.00	0.00%	2.65%	2.68%
Rural Rate Protection Charge	1,273	0.0003	0.38	1,273	0.0003	0.38	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,273	0.0000	0.00	1,273	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.15%
Sub-Total: Regulatory			**5.21**			**5.21**	**0.00**	**0.00%**	**3.01%**	**3.05%**
Debt Retirement Charge (DRC)	1,152	0.000	**0.00**	1,152	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**164.94**			**164.94**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	21.44		0.13	21.44	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**186.38**			**186.38**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.20		-0.08	-13.20	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**173.18**			**173.18**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**162.76**			**162.76**	**0.00**	**0.00%**		**95.24%**
HST		0.13	21.16		0.13	21.16	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**183.92**			**183.92**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.02		-0.08	-13.02	0.00	0.00%		-7.62%
Total Amount on TOU			**170.90**			**170.90**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	2300
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	2542
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	14.68%	
Energy Second Tier (kWh)	1,700	0.090	153.00	1,700	0.090	153.00	0.00	0.00%	48.61%	
Sub-Total: Energy (RPP)			**199.20**			**199.20**	**0.00**	**0.00%**	**63.29%**	
TOU-Off Peak	1,495	0.065	97.18	1,495	0.065	97.18	0.00	0.00%		32.18%
TOU-Mid Peak	391	0.095	37.15	391	0.095	37.15	0.00	0.00%		12.30%
TOU-On Peak	414	0.132	54.65	414	0.132	54.65	0.00	0.00%		18.09%
Sub-Total: Energy (TOU)			**188.97**			**188.97**	0.00	0.00%	**60.04%**	**62.57%**
Service Charge (RRRP credit applied)	1	25.02	25.02	1	34.09	34.09	9.07	36.25%	10.83%	11.29%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	2,300	0.0359	11.41	2,300	0.0321	2.34	-9.07	-79.49%	0.74%	0.77%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,300	0.0000	0.02	2,300	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.43**			**36.43**	**0.00**	**0.00%**	**11.58%**	**12.06%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.26%
Line Losses on Cost of Power (based on two-tier RPP prices)	242	0.0900	21.74	242	0.0900	21.74	0.00	0.00%	6.91%	7.20%
Line Losses on Cost of Power (based on TOU prices)	242	0.0822	19.84	242	0.0822	19.84	0.00	0.00%	6.30%	6.57%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.96**			**58.96**	**0.00**	**0.00%**	**18.73%**	**19.52%**
Sub-Total: Distribution (based on TOU prices)			**57.06**			**57.06**	**0.00**	**0.00%**	**18.13%**	**18.89%**
Retail Transmission Rate – Network Service Rate	2,542	0.0067	17.13	2,542	0.0067	17.13	0.00	0.00%	5.44%	5.67%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,542	0.0056	14.31	2,542	0.0056	14.31	0.00	0.00%	4.55%	4.74%
Sub-Total: Retail Transmission			**31.44**			**31.44**	**0.00**	**0.00%**	**9.99%**	**10.41%**
Sub-Total: Delivery (based on two-tier RPP prices)			**90.40**			**90.40**	**0.00**	**0.00%**	**28.72%**	**29.93%**
Sub-Total: Delivery (based on TOU prices)			**88.50**			**88.50**	**0.00**	**0.00%**	**28.12%**	**29.30%**
Wholesale Market Service Rate	2,542	0.0036	9.15	2,542	0.0036	9.15	0.00	0.00%	2.91%	3.03%
Rural Rate Protection Charge	2,542	0.0003	0.76	2,542	0.0003	0.76	0.00	0.00%	0.24%	0.25%
Ontario Electricity Support Program Charge	2,542	0.0000	0.00	2,542	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**10.16**			**10.16**	**0.00**	**0.00%**	**3.23%**	**3.36%**
Debt Retirement Charge (DRC)	2,300	0.000	**0.00**	2,300	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**299.76**			**299.76**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	38.97		0.13	38.97	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**338.73**			**338.73**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.98		-0.08	-23.98	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**314.75**			**314.75**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**287.63**			**287.63**	**0.00**	**0.00%**		**95.24%**
HST		0.13	37.39		0.13	37.39	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**325.02**			**325.02**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.01		-0.08	-23.01	0.00	0.00%		-7.62%
Total Amount on TOU			**302.01**			**302.01**	**0.00**	**0.00%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	50
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	55.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	50	0.077	3.85	50	0.077	3.85	0.00	0.00%	6.82%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**3.85**			**3.85**	**0.00**	**0.00%**	**6.82%**	
TOU-Off Peak	33	0.065	2.11	33	0.065	2.11	0.00	0.00%		3.72%
TOU-Mid Peak	9	0.095	0.81	9	0.095	0.81	0.00	0.00%		1.42%
TOU-On Peak	9	0.132	1.19	9	0.132	1.19	0.00	0.00%		2.09%
Sub-Total: Energy (TOU)			**4.11**			**4.11**	0.00	0.00%	**7.27%**	**7.23%**
Service Charge	1	40.52	40.52	1	45.07	45.07	4.55	11.23%	79.80%	79.37%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	50	0.0601	3.01	50	0.0528	2.64	-0.37	-12.15%	4.67%	4.65%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	50	0.0000	0.00	50	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**43.52**			**47.71**	**4.19**	**9.62%**	**84.47%**	**84.02%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.40%	1.39%
Line Losses on Cost of Power (based on two-tier RPP prices)	5	0.0770	0.40	5	0.0770	0.40	0.00	0.00%	0.71%	0.71%
Line Losses on Cost of Power (based on TOU prices)	5	0.0822	0.43	5	0.0822	0.43	0.00	0.00%	0.76%	0.75%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.71**			**48.90**	**4.19**	**9.36%**	**86.57%**	**86.12%**
Sub-Total: Distribution (based on TOU prices)			**44.74**			**48.93**	**4.19**	**9.35%**	**86.62%**	**86.17%**
Retail Transmission Rate – Network Service Rate	55	0.0057	0.31	55	0.0057	0.31	0.00	0.00%	0.55%	0.55%
Retail Transmission Rate – Line and Transformation Connection Service Rate	55	0.0048	0.27	55	0.0048	0.27	0.00	0.00%	0.47%	0.47%
Sub-Total: Retail Transmission			**0.58**			**0.58**	**0.00**	**0.00%**	**1.02%**	**1.02%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.29**			**49.48**	**4.19**	**9.24%**	**87.60%**	**87.14%**
Sub-Total: Delivery (based on TOU prices)			**45.32**			**49.50**	**4.19**	**9.23%**	**87.65%**	**87.18%**
Wholesale Market Service Rate	55	0.0036	0.20	55	0.0036	0.20	0.00	0.00%	0.35%	0.35%
Rural Rate Protection Charge	55	0.0003	0.02	55	0.0003	0.02	0.00	0.00%	0.03%	0.03%
Ontario Electricity Support Program Charge	55	0.0000	0.00	55	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.44%	0.44%
Sub-Total: Regulatory			**0.47**			**0.47**	**0.00**	**0.00%**	**0.82%**	**0.82%**
Debt Retirement Charge (DRC)	50	0.000	**0.00**	50	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**49.61**			**53.79**	**4.19**	**8.44%**	**95.24%**	
HST		0.13	6.45		0.13	6.99	0.54	8.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**56.06**			**60.79**	**4.73**	**8.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.97		-0.08	-4.30	-0.33	-8.44%	-7.62%	
Total Amount on Two-Tier RPP			**52.09**			**56.48**	**4.39**	**8.44%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**49.89**			**54.08**	**4.19**	**8.39%**		**95.24%**
HST		0.13	6.49		0.13	7.03	0.54	8.39%		12.38%
Total Electricity Charge on TOU (including HST)			**56.38**			**61.11**	**4.73**	**8.39%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.99		-0.08	-4.33	-0.33	-8.39%		-7.62%
Total Amount on TOU			**52.39**			**56.78**	**4.39**	**8.39%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	352
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	388.608
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	352	0.077	27.10	352	0.077	27.10	0.00	0.00%	25.76%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**27.10**			**27.10**	**0.00**	**0.00%**	**25.76%**	
TOU-Off Peak	229	0.065	14.87	229	0.065	14.87	0.00	0.00%		13.86%
TOU-Mid Peak	60	0.095	5.68	60	0.095	5.68	0.00	0.00%		5.30%
TOU-On Peak	63	0.132	8.36	63	0.132	8.36	0.00	0.00%		7.79%
Sub-Total: Energy (TOU)			**28.92**			**28.92**	0.00	0.00%	**27.49%**	**26.95%**
Service Charge	1	40.52	40.52	1	45.07	45.07	4.55	11.23%	42.84%	41.99%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	352	0.0601	21.16	352	0.0528	18.59	-2.57	-12.15%	17.66%	17.32%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	352	0.0000	0.00	352	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**61.68**			**63.66**	**1.98**	**3.21%**	**60.50%**	**59.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.75%	0.74%
Line Losses on Cost of Power (based on two-tier RPP prices)	37	0.0770	2.82	37	0.0770	2.82	0.00	0.00%	2.68%	2.63%
Line Losses on Cost of Power (based on TOU prices)	37	0.0822	3.01	37	0.0822	3.01	0.00	0.00%	2.86%	2.80%
Sub-Total: Distribution (based on two-tier RPP prices)			**65.29**			**67.27**	**1.98**	**3.03%**	**63.93%**	**62.68%**
Sub-Total: Distribution (based on TOU prices)			**65.47**			**67.45**	**1.98**	**3.02%**	**64.11%**	**62.85%**
Retail Transmission Rate – Network Service Rate	389	0.0057	2.20	389	0.0057	2.20	0.00	0.00%	2.09%	2.05%
Retail Transmission Rate – Line and Transformation Connection Service Rate	389	0.0048	1.87	389	0.0048	1.87	0.00	0.00%	1.78%	1.75%
Sub-Total: Retail Transmission			**4.07**			**4.07**	**0.00**	**0.00%**	**3.87%**	**3.79%**
Sub-Total: Delivery (based on two-tier RPP prices)			**69.36**			**71.34**	**1.98**	**2.86%**	**67.80%**	**66.47%**
Sub-Total: Delivery (based on TOU prices)			**69.55**			**71.53**	**1.98**	**2.85%**	**67.98%**	**66.65%**
Wholesale Market Service Rate	389	0.0036	1.40	389	0.0036	1.40	0.00	0.00%	1.33%	1.30%
Rural Rate Protection Charge	389	0.0003	0.12	389	0.0003	0.12	0.00	0.00%	0.11%	0.11%
Ontario Electricity Support Program Charge	389	0.0000	0.00	389	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.24%	0.23%
Sub-Total: Regulatory			**1.77**			**1.77**	**0.00**	**0.00%**	**1.68%**	**1.65%**
Debt Retirement Charge (DRC)	352	0.000	**0.00**	352	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**98.23**			**100.21**	**1.98**	**2.02%**	**95.24%**	
HST		0.13	12.77		0.13	13.03	0.26	2.02%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**111.00**			**113.23**	**2.24**	**2.02%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.86		-0.08	-8.02	-0.16	-2.02%	-7.62%	
Total Amount on Two-Tier RPP			**103.14**			**105.22**	**2.08**	**2.02%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**100.23**			**102.21**	**1.98**	**1.98%**		**95.24%**
HST		0.13	13.03		0.13	13.29	0.26	1.98%		12.38%
Total Electricity Charge on TOU (including HST)			**113.26**			**115.50**	**2.24**	**1.98%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.02		-0.08	-8.18	-0.16	-1.98%		-7.62%
Total Amount on TOU			**105.24**			**107.32**	**2.08**	**1.98%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1104
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	21.32%	
Energy Second Tier (kWh)	400	0.090	36.00	400	0.090	36.00	0.00	0.00%	16.62%	
Sub-Total: Energy (RPP)			**82.20**			**82.20**	**0.00**	**0.00%**	**37.94%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.58%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.48%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		11.01%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**37.92%**	**38.08%**
Service Charge	1	40.52	40.52	1	45.07	45.07	4.55	11.23%	20.80%	20.89%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0601	60.10	1,000	0.0528	52.80	-7.30	-12.15%	24.37%	24.47%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.01	1,000	0.0000	0.01	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**100.63**			**97.88**	**-2.75**	**-2.73%**	**45.17%**	**45.36%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.36%	0.37%
Line Losses on Cost of Power (based on two-tier RPP prices)	104	0.0900	9.36	104	0.0900	9.36	0.00	0.00%	4.32%	4.34%
Line Losses on Cost of Power (based on TOU prices)	104	0.0822	8.54	104	0.0822	8.54	0.00	0.00%	3.94%	3.96%
Sub-Total: Distribution (based on two-tier RPP prices)			**110.78**			**108.03**	**-2.75**	**-2.48%**	**49.86%**	**50.07%**
Sub-Total: Distribution (based on TOU prices)			**109.96**			**107.21**	**-2.75**	**-2.50%**	**49.48%**	**49.69%**
Retail Transmission Rate – Network Service Rate	1,104	0.0057	6.24	1,104	0.0057	6.24	0.00	0.00%	2.88%	2.89%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,104	0.0048	5.32	1,104	0.0048	5.32	0.00	0.00%	2.46%	2.47%
Sub-Total: Retail Transmission			**11.57**			**11.57**	**0.00**	**0.00%**	**5.34%**	**5.36%**
Sub-Total: Delivery (based on two-tier RPP prices)			**122.34**			**119.59**	**-2.75**	**-2.25%**	**55.20%**	**55.43%**
Sub-Total: Delivery (based on TOU prices)			**121.53**			**118.78**	**-2.75**	**-2.26%**	**54.82%**	**55.05%**
Wholesale Market Service Rate	1,104	0.0036	3.97	1,104	0.0036	3.97	0.00	0.00%	1.83%	1.84%
Rural Rate Protection Charge	1,104	0.0003	0.33	1,104	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,104	0.0000	0.00	1,104	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.12%
Sub-Total: Regulatory			**4.56**			**4.56**	**0.00**	**0.00%**	**2.10%**	**2.11%**
Debt Retirement Charge (DRC)	1,000	0.000	**0.00**	1,000	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**209.10**			**206.35**	**-2.75**	**-1.32%**	**95.24%**	
HST		0.13	27.18		0.13	26.83	-0.36	-1.32%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**236.28**			**233.18**	**-3.11**	**-1.32%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.73		-0.08	-16.51	0.22	1.32%	-7.62%	
Total Amount on Two-Tier RPP			**219.56**			**216.67**	**-2.89**	**-1.32%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**208.24**			**205.49**	**-2.75**	**-1.32%**		**95.24%**
HST		0.13	27.07		0.13	26.71	-0.36	-1.32%		12.38%
Total Electricity Charge on TOU (including HST)			**235.32**			**232.21**	**-3.11**	**-1.32%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.66		-0.08	-16.44	0.22	1.32%		-7.62%
Total Amount on TOU			**218.66**			**215.77**	**-2.89**	**-1.32%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1067
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	33.65%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	13.11%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**46.75%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		24.41%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.33%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.73%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**47.87%**	**47.47%**
Service Charge	1	23.88	23.88	1	24.47	24.47	0.59	2.47%	14.26%	14.14%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0278	27.80	1,000	0.029	29.00	1.20	4.32%	16.90%	16.75%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.03	1,000	0.0000	0.03	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**51.72**			**53.51**	**1.79**	**3.46%**	**31.17%**	**30.91%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.03	67	0.0900	6.03	0.00	0.00%	3.51%	3.48%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.50	67	0.0822	5.50	0.00	0.00%	3.21%	3.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.54**			**60.33**	**1.79**	**3.06%**	**35.15%**	**34.85%**
Sub-Total: Distribution (based on TOU prices)			**58.01**			**59.80**	**1.79**	**3.09%**	**34.84%**	**34.55%**
Retail Transmission Rate – Network Service Rate	1,067	0.0061	6.52	1,067	0.0061	6.52	0.00	0.00%	3.80%	3.76%
Retail Transmission Rate – Line and Transformation Connection S	1,067	0.0047	4.96	1,067	0.0047	4.96	0.00	0.00%	2.89%	2.87%
Sub-Total: Retail Transmission			**11.48**			**11.48**	**0.00**	**0.00%**	**6.69%**	**6.63%**
Sub-Total: Delivery (based on two-tier RPP prices)			**70.02**			**71.81**	**1.79**	**2.56%**	**41.84%**	**41.48%**
Sub-Total: Delivery (based on TOU prices)			**69.49**			**71.28**	**1.79**	**2.58%**	**41.53%**	**41.18%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.24%	2.22%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.19%	0.18%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.15%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.57%**	**2.55%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.08%**	**4.04%**
Total Electricty Charge on Two-Tier RPP			**161.68**			**163.47**	**1.79**	**1.11%**	**95.24%**	
HST		0.13	21.02		0.13	21.25	0.23	1.11%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**182.70**			**184.72**	**2.02**	**1.11%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.93		-0.08	-13.08	-0.14	-1.11%	-7.62%	
Total Amount on Two-Tier RPP			**169.76**			**171.64**	**1.88**	**1.11%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**163.06**			**164.85**	**1.79**	**1.10%**		**95.24%**
HST		0.13	21.20		0.13	21.43	0.23	1.10%		12.38%
Total Electricity Charge on TOU (including HST)			**184.26**			**186.28**	**2.02**	**1.10%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.05		-0.08	-13.19	-0.14	-1.10%		-7.62%
Total Amount on TOU			**171.22**			**173.10**	**1.88**	**1.10%**		**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2134
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.68%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	34.43%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**52.11%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		26.46%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.11%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		14.88%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**50.29%**	**51.45%**
Service Charge	1	23.88	23.88	1	24.47	24.47	0.59	2.47%	7.49%	7.66%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0278	55.60	2,000	0.029	58.00	2.40	4.32%	17.75%	18.16%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.06	2,000	0.0000	0.06	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**79.55**			**82.54**	**2.99**	**3.76%**	**25.26%**	**25.84%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	134	0.0900	12.06	134	0.0900	12.06	0.00	0.00%	3.69%	3.78%
Line Losses on Cost of Power (based on TOU prices)	134	0.0822	11.01	134	0.0822	11.01	0.00	0.00%	3.37%	3.45%
Sub-Total: Distribution (based on two-tier RPP prices)			**92.40**			**95.39**	**2.99**	**3.24%**	**29.20%**	**29.87%**
Sub-Total: Distribution (based on TOU prices)			**91.35**			**94.34**	**2.99**	**3.27%**	**28.87%**	**29.54%**
Retail Transmission Rate – Network Service Rate	2,134	0.0061	13.03	2,134	0.0061	13.03	0.00	0.00%	3.99%	4.08%
Retail Transmission Rate – Line and Transformation Connection S	2,134	0.0047	9.93	2,134	0.0047	9.93	0.00	0.00%	3.04%	3.11%
Sub-Total: Retail Transmission			**22.96**			**22.96**	**0.00**	**0.00%**	**7.03%**	**7.19%**
Sub-Total: Delivery (based on two-tier RPP prices)			**115.36**			**118.35**	**2.99**	**2.59%**	**36.22%**	**37.05%**
Sub-Total: Delivery (based on TOU prices)			**114.31**			**117.30**	**2.99**	**2.62%**	**35.90%**	**36.72%**
Wholesale Market Service Rate	2,134	0.0036	7.68	2,134	0.0036	7.68	0.00	0.00%	2.35%	2.41%
Rural Rate Protection Charge	2,134	0.0003	0.64	2,134	0.0003	0.64	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,134	0.0000	0.00	2,134	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.62%**	**2.68%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.28%**	**4.38%**
Total Electricty Charge on Two-Tier RPP			**308.18**			**311.17**	**2.99**	**0.97%**	**95.24%**	
HST		0.13	40.06		0.13	40.45	0.39	0.97%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**348.24**			**351.62**	**3.38**	**0.97%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.65		-0.08	-24.89	-0.24	-0.97%	-7.62%	
Total Amount on Two-Tier RPP			**323.59**			**326.73**	**3.14**	**0.97%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**301.20**			**304.19**	**2.99**	**0.99%**		**95.24%**
HST		0.13	39.16		0.13	39.54	0.39	0.99%		12.38%
Total Electricity Charge on TOU (including HST)			**340.35**			**343.73**	**3.38**	**0.99%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.10		-0.08	-24.34	-0.24	-0.99%		-7.62%
Total Amount on TOU			**316.26**			**319.40**	**3.14**	**0.99%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2759
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2944
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.99%	
Energy Second Tier (kWh)	2,009	0.090	180.81	2,009	0.090	180.81	0.00	0.00%	40.68%	
Sub-Total: Energy (RPP)			**238.56**			**238.56**	**0.00**	**0.00%**	**53.68%**	
TOU-Off Peak	1,793	0.065	116.57	1,793	0.065	116.57	0.00	0.00%		27.08%
TOU-Mid Peak	469	0.095	44.56	469	0.095	44.56	0.00	0.00%		10.35%
TOU-On Peak	497	0.132	65.55	497	0.132	65.55	0.00	0.00%		15.23%
Sub-Total: Energy (TOU)			**226.68**			**226.68**	0.00	0.00%	**51.00%**	**52.66%**
Service Charge	1	23.88	23.88	1	24.47	24.47	0.59	2.47%	5.51%	5.68%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,759	0.0278	76.70	2,759	0.029	80.01	3.31	4.32%	18.00%	18.59%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,759	0.0000	0.08	2,759	0.0000	0.08	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**100.67**			**104.57**	**3.90**	**3.87%**	**23.53%**	**24.29%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.18%	0.18%
Line Losses on Cost of Power (based on two-tier RPP prices)	185	0.0900	16.64	185	0.0900	16.64	0.00	0.00%	3.74%	3.87%
Line Losses on Cost of Power (based on TOU prices)	185	0.0822	15.19	185	0.0822	15.19	0.00	0.00%	3.42%	3.53%
Sub-Total: Distribution (based on two-tier RPP prices)			**118.10**			**122.00**	**3.90**	**3.30%**	**27.45%**	**28.34%**
Sub-Total: Distribution (based on TOU prices)			**116.65**			**120.55**	**3.90**	**3.34%**	**27.12%**	**28.01%**
Retail Transmission Rate – Network Service Rate	2,944	0.0061	17.98	2,944	0.0061	17.98	0.00	0.00%	4.04%	4.18%
Retail Transmission Rate – Line and Transformation Connection S	2,944	0.0047	13.69	2,944	0.0047	13.69	0.00	0.00%	3.08%	3.18%
Sub-Total: Retail Transmission			**31.67**			**31.67**	**0.00**	**0.00%**	**7.13%**	**7.36%**
Sub-Total: Delivery (based on two-tier RPP prices)			**149.77**			**153.67**	**3.90**	**2.60%**	**34.58%**	**35.70%**
Sub-Total: Delivery (based on TOU prices)			**148.32**			**152.22**	**3.90**	**2.63%**	**34.25%**	**35.36%**
Wholesale Market Service Rate	2,944	0.0036	10.60	2,944	0.0036	10.60	0.00	0.00%	2.38%	2.46%
Rural Rate Protection Charge	2,944	0.0003	0.88	2,944	0.0003	0.88	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	2,944	0.0000	0.00	2,944	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.73**			**11.73**	**0.00**	**0.00%**	**2.64%**	**2.73%**
Debt Retirement Charge (DRC)	2,759	0.007	**19.31**	2,759	0.007	**19.31**	**0.00**	**0.00%**	**4.35%**	**4.49%**
Total Electricty Charge on Two-Tier RPP			**419.37**			**423.27**	**3.90**	**0.93%**	**95.24%**	
HST		0.13	54.52		0.13	55.03	0.51	0.93%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**473.89**			**478.30**	**4.41**	**0.93%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.55		-0.08	-33.86	-0.31	-0.93%	-7.62%	
Total Amount on Two-Tier RPP			**440.34**			**444.44**	**4.10**	**0.93%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**406.04**			**409.94**	**3.90**	**0.96%**		**95.24%**
HST		0.13	52.79		0.13	53.29	0.51	0.96%		12.38%
Total Electricity Charge on TOU (including HST)			**458.83**			**463.24**	**4.41**	**0.96%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-32.48		-0.08	-32.80	-0.31	-0.96%		-7.62%
Total Amount on TOU			**426.34**			**430.44**	**4.10**	**0.96%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16005
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.46%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	54.74%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**57.21%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		28.53%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		10.91%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		16.04%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**52.60%**	**55.48%**
Service Charge	1	23.88	23.88	1	24.47	24.47	0.59	2.47%	1.04%	1.10%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0278	417.00	15,000	0.029	435.00	18.00	4.32%	18.57%	19.58%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.45	15,000	0.0000	0.45	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**441.34**			**459.93**	**18.59**	**4.21%**	**19.63%**	**20.71%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,005	0.0900	90.45	1,005	0.0900	90.45	0.00	0.00%	3.86%	4.07%
Line Losses on Cost of Power (based on TOU prices)	1,005	0.0822	82.57	1,005	0.0822	82.57	0.00	0.00%	3.52%	3.72%
Sub-Total: Distribution (based on two-tier RPP prices)			**532.58**			**551.17**	**18.59**	**3.49%**	**23.53%**	**24.81%**
Sub-Total: Distribution (based on TOU prices)			**524.70**			**543.29**	**18.59**	**3.54%**	**23.19%**	**24.46%**
Retail Transmission Rate – Network Service Rate	16,005	0.0061	97.73	16,005	0.0061	97.73	0.00	0.00%	4.17%	4.40%
Retail Transmission Rate – Line and Transformation Connection S	16,005	0.0047	74.46	16,005	0.0047	74.46	0.00	0.00%	3.18%	3.35%
Sub-Total: Retail Transmission			**172.18**			**172.18**	**0.00**	**0.00%**	**7.35%**	**7.75%**
Sub-Total: Delivery (based on two-tier RPP prices)			**704.76**			**723.35**	**18.59**	**2.64%**	**30.88%**	**32.56%**
Sub-Total: Delivery (based on TOU prices)			**696.88**			**715.47**	**18.59**	**2.67%**	**30.54%**	**32.21%**
Wholesale Market Service Rate	16,005	0.0036	57.62	16,005	0.0036	57.62	0.00	0.00%	2.46%	2.59%
Rural Rate Protection Charge	16,005	0.0003	4.80	16,005	0.0003	4.80	0.00	0.00%	0.20%	0.22%
Ontario Electricity Support Program Charge	16,005	0.0000	0.00	16,005	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.67**			**62.67**	**0.00**	**0.00%**	**2.67%**	**2.82%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.48%**	**4.73%**
Total Electricty Charge on Two-Tier RPP			**2,212.68**			**2,231.27**	**18.59**	**0.84%**	**95.24%**	
HST		0.13	287.65		0.13	290.07	2.42	0.84%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,500.33**			**2,521.33**	**21.01**	**0.84%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-177.01		-0.08	-178.50	-1.49	-0.84%	-7.62%	
Total Amount on Two-Tier RPP			**2,323.31**			**2,342.83**	**19.52**	**0.84%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,096.95**			**2,115.54**	**18.59**	**0.89%**		**95.24%**
HST		0.13	272.60		0.13	275.02	2.42	0.89%		12.38%
Total Electricity Charge on TOU (including HST)			**2,369.55**			**2,390.56**	**21.01**	**0.89%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-167.76		-0.08	-169.24	-1.49	-0.89%		-7.62%
Total Amount on TOU			**2,201.80**			**2,221.32**	**19.52**	**0.89%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1096
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	26.98%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	10.51%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**37.49%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.63%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.50%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		11.04%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**38.38%**	**38.16%**
Service Charge	1	29.56	29.56	1	30.2	30.20	0.64	2.17%	14.11%	14.03%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0589	58.90	1,000	0.0613	61.30	2.40	4.07%	28.64%	28.47%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.02	1,000	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**88.48**			**91.52**	**3.04**	**3.44%**	**42.75%**	**42.51%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.37%	0.37%
Line Losses on Cost of Power (based on two-tier RPP prices)	96	0.0900	8.64	96	0.0900	8.64	0.00	0.00%	4.04%	4.01%
Line Losses on Cost of Power (based on TOU prices)	96	0.0822	7.89	96	0.0822	7.89	0.00	0.00%	3.68%	3.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**97.91**			**100.95**	**3.04**	**3.10%**	**47.16%**	**46.89%**
Sub-Total: Distribution (based on TOU prices)			**97.16**			**100.20**	**3.04**	**3.13%**	**46.81%**	**46.54%**
Retail Transmission Rate – Network Service Rate	1,096	0.0057	6.24	1,096	0.0057	6.24	0.00	0.00%	2.91%	2.90%
Retail Transmission Rate – Line and Transformation Connection S	1,096	0.0045	4.90	1,096	0.0045	4.90	0.00	0.00%	2.29%	2.28%
Sub-Total: Retail Transmission			**11.14**			**11.14**	**0.00**	**0.00%**	**5.21%**	**5.18%**
Sub-Total: Delivery (based on two-tier RPP prices)			**109.06**			**112.10**	**3.04**	**2.79%**	**52.37%**	**52.07%**
Sub-Total: Delivery (based on TOU prices)			**108.30**			**111.34**	**3.04**	**2.81%**	**52.01%**	**51.72%**
Wholesale Market Service Rate	1,096	0.0036	3.95	1,096	0.0036	3.95	0.00	0.00%	1.84%	1.83%
Rural Rate Protection Charge	1,096	0.0003	0.33	1,096	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,096	0.0000	0.00	1,096	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.12%
Sub-Total: Regulatory			**4.52**			**4.52**	**0.00**	**0.00%**	**2.11%**	**2.10%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.27%**	**3.25%**
Total Electricty Charge on Two-Tier RPP			**200.83**			**203.87**	**3.04**	**1.51%**	**95.24%**	
HST		0.13	26.11		0.13	26.50	0.40	1.51%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**226.94**			**230.37**	**3.44**	**1.51%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.07		-0.08	-16.31	-0.24	-1.51%	-7.62%	
Total Amount on Two-Tier RPP			**210.87**			**214.06**	**3.19**	**1.51%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**201.99**			**205.03**	**3.04**	**1.51%**		**95.24%**
HST		0.13	26.26		0.13	26.65	0.40	1.51%		12.38%
Total Electricity Charge on TOU (including HST)			**228.25**			**231.68**	**3.44**	**1.51%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.16		-0.08	-16.40	-0.24	-1.51%		-7.62%
Total Amount on TOU			**212.09**			**215.28**	**3.19**	**1.51%**		**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2192
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.24%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	27.74%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**41.98%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		21.24%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		8.12%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		11.95%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**40.52%**	**41.31%**
Service Charge	1	29.56	29.56	1	30.20	30.20	0.64	2.17%	7.45%	7.59%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0589	117.80	2,000	0.0613	122.60	4.80	4.07%	30.23%	30.82%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.04	2,000	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**147.40**			**152.84**	**5.44**	**3.69%**	**37.69%**	**38.43%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	192	0.0900	17.28	192	0.0900	17.28	0.00	0.00%	4.26%	4.34%
Line Losses on Cost of Power (based on TOU prices)	192	0.0822	15.77	192	0.0822	15.77	0.00	0.00%	3.89%	3.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**165.47**			**170.91**	**5.44**	**3.29%**	**42.14%**	**42.97%**
Sub-Total: Distribution (based on TOU prices)			**163.97**			**169.41**	**5.44**	**3.32%**	**41.77%**	**42.59%**
Retail Transmission Rate – Network Service Rate	2,192	0.0057	12.48	2,192	0.0057	12.48	0.00	0.00%	3.08%	3.14%
Retail Transmission Rate – Line and Transformation Connection S	2,192	0.0045	9.81	2,192	0.0045	9.81	0.00	0.00%	2.42%	2.47%
Sub-Total: Retail Transmission			**22.29**			**22.29**	**0.00**	**0.00%**	**5.50%**	**5.60%**
Sub-Total: Delivery (based on two-tier RPP prices)			**187.76**			**193.20**	**5.44**	**2.90%**	**47.64%**	**48.57%**
Sub-Total: Delivery (based on TOU prices)			**186.25**			**191.69**	**5.44**	**2.92%**	**47.27%**	**48.19%**
Wholesale Market Service Rate	2,192	0.0036	7.89	2,192	0.0036	7.89	0.00	0.00%	1.95%	1.98%
Rural Rate Protection Charge	2,192	0.0003	0.66	2,192	0.0003	0.66	0.00	0.00%	0.16%	0.17%
Ontario Electricity Support Program Charge	2,192	0.0000	0.00	2,192	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.80**			**8.80**	**0.00**	**0.00%**	**2.17%**	**2.21%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.45%**	**3.52%**
Total Electricty Charge on Two-Tier RPP			**380.81**			**386.25**	**5.44**	**1.43%**	**95.24%**	
HST		0.13	49.50		0.13	50.21	0.71	1.43%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**430.31**			**436.46**	**6.15**	**1.43%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.46		-0.08	-30.90	-0.44	-1.43%	-7.62%	
Total Amount on Two-Tier RPP			**399.85**			**405.56**	**5.71**	**1.43%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**373.37**			**378.81**	**5.44**	**1.46%**		**95.24%**
HST		0.13	48.54		0.13	49.25	0.71	1.46%		12.38%
Total Electricity Charge on TOU (including HST)			**421.91**			**428.06**	**6.15**	**1.46%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.87		-0.08	-30.30	-0.44	-1.46%		-7.62%
Total Amount on TOU			**392.04**			**397.75**	**5.71**	**1.46%**		**100.00%**

2019 Bill Impacts (Average Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1982
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2172
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.36%	
Energy Second Tier (kWh)	1,232	0.090	110.88	1,232	0.090	110.88	0.00	0.00%	27.57%	
Sub-Total: Energy (RPP)			**168.63**			**168.63**	**0.00**	**0.00%**	**41.94%**	
TOU-Off Peak	1,288	0.065	83.74	1,288	0.065	83.74	0.00	0.00%		21.23%
TOU-Mid Peak	337	0.095	32.01	337	0.095	32.01	0.00	0.00%		8.11%
TOU-On Peak	357	0.132	47.09	357	0.132	47.09	0.00	0.00%		11.94%
Sub-Total: Energy (TOU)			**162.84**			**162.84**	0.00	0.00%	**40.50%**	**41.28%**
Service Charge	1	29.56	29.56	1	30.2	30.20	0.64	2.17%	7.51%	7.66%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,982	0.0589	116.74	1,982	0.0613	121.50	4.76	4.07%	30.21%	30.80%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,982	0.0000	0.04	1,982	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**146.34**			**151.74**	**5.40**	**3.69%**	**37.74%**	**38.47%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.20%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	190	0.0900	17.12	190	0.0900	17.12	0.00	0.00%	4.26%	4.34%
Line Losses on Cost of Power (based on TOU prices)	190	0.0822	15.63	190	0.0822	15.63	0.00	0.00%	3.89%	3.96%
Sub-Total: Distribution (based on two-tier RPP prices)			**164.26**			**169.65**	**5.40**	**3.29%**	**42.19%**	**43.01%**
Sub-Total: Distribution (based on TOU prices)			**162.76**			**168.16**	**5.40**	**3.32%**	**41.82%**	**42.63%**
Retail Transmission Rate – Network Service Rate	2,172	0.0057	12.37	2,172	0.0057	12.37	0.00	0.00%	3.08%	3.14%
Retail Transmission Rate – Line and Transformation Connection S	2,172	0.0045	9.72	2,172	0.0045	9.72	0.00	0.00%	2.42%	2.46%
Sub-Total: Retail Transmission			**22.09**			**22.09**	**0.00**	**0.00%**	**5.49%**	**5.60%**
Sub-Total: Delivery (based on two-tier RPP prices)			**186.34**			**191.74**	**5.40**	**2.90%**	**47.68%**	**48.61%**
Sub-Total: Delivery (based on TOU prices)			**184.85**			**190.25**	**5.40**	**2.92%**	**47.31%**	**48.23%**
Wholesale Market Service Rate	2,172	0.0036	7.82	2,172	0.0036	7.82	0.00	0.00%	1.94%	1.98%
Rural Rate Protection Charge	2,172	0.0003	0.65	2,172	0.0003	0.65	0.00	0.00%	0.16%	0.17%
Ontario Electricity Support Program Charge	2,172	0.0000	0.00	2,172	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.72**			**8.72**	**0.00**	**0.00%**	**2.17%**	**2.21%**
Debt Retirement Charge (DRC)	1,982	0.007	**13.87**	1,982	0.007	**13.87**	**0.00**	**0.00%**	**3.45%**	**3.52%**
Total Electricty Charge on Two-Tier RPP			**377.57**			**382.96**	**5.40**	**1.43%**	**95.24%**	
HST		0.13	49.08		0.13	49.79	0.70	1.43%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**426.65**			**432.75**	**6.10**	**1.43%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.21		-0.08	-30.64	-0.43	-1.43%	-7.62%	
Total Amount on Two-Tier RPP			**396.45**			**402.11**	**5.67**	**1.43%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**370.29**			**375.68**	**5.40**	**1.46%**		**95.24%**
HST		0.13	48.14		0.13	48.84	0.70	1.46%		12.38%
Total Electricity Charge on TOU (including HST)			**418.42**			**424.52**	**6.10**	**1.46%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.62		-0.08	-30.05	-0.43	-1.46%		-7.62%
Total Amount on TOU			**388.80**			**394.47**	**5.67**	**1.46%**		**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16440
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	1.99%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	44.30%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**46.30%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		22.88%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		8.75%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		12.87%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**42.57%**	**44.49%**
Service Charge	1	29.56	29.56	1	30.2	30.20	0.64	2.17%	1.04%	1.09%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0589	883.50	15,000	0.0613	919.50	36.00	4.07%	31.76%	33.20%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.30	15,000	0.0000	0.30	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**913.36**			**950.00**	**36.64**	**4.01%**	**32.82%**	**34.30%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,440	0.0900	129.60	1,440	0.0900	129.60	0.00	0.00%	4.48%	4.68%
Line Losses on Cost of Power (based on TOU prices)	1,440	0.0822	118.31	1,440	0.0822	118.31	0.00	0.00%	4.09%	4.27%
Sub-Total: Distribution (based on two-tier RPP prices)			**1,043.75**			**1,080.39**	**36.64**	**3.51%**	**37.32%**	**39.00%**
Sub-Total: Distribution (based on TOU prices)			**1,032.46**			**1,069.10**	**36.64**	**3.55%**	**36.93%**	**38.60%**
Retail Transmission Rate – Network Service Rate	16,440	0.0057	93.59	16,440	0.0057	93.59	0.00	0.00%	3.23%	3.38%
Retail Transmission Rate – Line and Transformation Connection S	16,440	0.0045	73.55	16,440	0.0045	73.55	0.00	0.00%	2.54%	2.66%
Sub-Total: Retail Transmission			**167.15**			**167.15**	**0.00**	**0.00%**	**5.77%**	**6.03%**
Sub-Total: Delivery (based on two-tier RPP prices)			**1,210.90**			**1,247.54**	**36.64**	**3.03%**	**43.09%**	**45.04%**
Sub-Total: Delivery (based on TOU prices)			**1,199.61**			**1,236.25**	**36.64**	**3.05%**	**42.70%**	**44.63%**
Wholesale Market Service Rate	16,440	0.0036	59.18	16,440	0.0036	59.18	0.00	0.00%	2.04%	2.14%
Rural Rate Protection Charge	16,440	0.0003	4.93	16,440	0.0003	4.93	0.00	0.00%	0.17%	0.18%
Ontario Electricity Support Program Charge	16,440	0.0000	0.00	16,440	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**64.37**			**64.37**	**0.00**	**0.00%**	**2.22%**	**2.32%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.63%**	**3.79%**
Total Electricty Charge on Two-Tier RPP			**2,720.51**			**2,757.15**	**36.64**	**1.35%**	**95.24%**	
HST		0.13	353.67		0.13	358.43	4.76	1.35%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**3,074.18**			**3,115.58**	**41.40**	**1.35%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-217.64		-0.08	-220.57	-2.93	-1.35%	-7.62%	
Total Amount on Two-Tier RPP			**2,856.54**			**2,895.01**	**38.47**	**1.35%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,601.37**			**2,638.01**	**36.64**	**1.41%**		**95.24%**
HST		0.13	338.18		0.13	342.94	4.76	1.41%		12.38%
Total Electricity Charge on TOU (including HST)			**2,939.55**			**2,980.96**	**41.40**	**1.41%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-208.11		-0.08	-211.04	-2.93	-1.41%		-7.62%
Total Amount on TOU			**2,731.44**			**2,769.91**	**38.47**	**1.41%**		**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.050
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,750	0.077	1,212.75	15,750	0.077	1,212.75	0.00	0.00%	46.30%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,212.75**			**1,212.75**	**0.00**	**0.00%**	**46.30%**
Service Charge	1	100.72	100.72	1	102.72	102.72	2.00	1.99%	3.92%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	9.6226	577.36	60	9.9799	598.79	21.44	3.71%	22.86%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0112	0.67	60	0.0112	0.67	0.00	0.00%	0.03%
Volumetric Global Adjustment Account Rider	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**678.76**			**702.20**	**23.44**	**3.45%**	**26.81%**
Retail Transmission Rate – Network Service Rate	60	2.23104	133.86	60	2.2310	133.86	0.00	0.00%	5.11%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.704675	102.28	60	1.7047	102.28	0.00	0.00%	3.91%
Sub-Total: Retail Transmission			**236.14**			**236.14**	**0.00**	**0.00%**	**9.02%**
Sub-Total: Delivery			**914.91**			**938.35**	**23.44**	**2.56%**	**35.83%**
Wholesale Market Service Rate	15,750	0.0036	56.70	15,750	0.0036	56.70	0.00	0.00%	2.16%
Rural Rate Protection Charge	15,750	0.0003	4.73	15,750	0.0003	4.73	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.68**			**61.68**	**0.00**	**0.00%**	**2.35%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.01%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,294.33**			**2,317.77**	**23.44**	**1.02%**	**88.50%**
HST		0.13	298.26		0.13	301.31	3.05	1.02%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,592.60**			**2,619.08**	**26.48**	**1.02%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,592.60**			**2,619.08**	**26.48**	**1.02%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	50,525
Peak (kW)	135
Loss factor	1.050
Load factor	51%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	53,051
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	53,051	0.077	4,084.95	53,051	0.077	4,084.95	0.00	0.00%	54.54%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,084.95**			**4,084.95**	**0.00**	**0.00%**	**54.54%**
Service Charge	1	100.72	100.72	1	102.72	102.72	2.00	1.99%	1.37%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	135	9.6226	1,299.05	135	9.9799	1,347.29	48.24	3.71%	17.99%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	135	0.0112	1.51	135	0.0112	1.51	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,401.30**			**1,451.53**	**50.24**	**3.58%**	**19.38%**
Retail Transmission Rate – Network Service Rate	135	2.23104	301.19	135	2.2310	301.19	0.00	0.00%	4.02%
Retail Transmission Rate – Line and Transformation Connection Service Rate	135	1.704675	230.13	135	1.7047	230.13	0.00	0.00%	3.07%
Sub-Total: Retail Transmission			**531.32**			**531.32**	**0.00**	**0.00%**	**7.09%**
Sub-Total: Delivery			**1,932.62**			**1,982.86**	**50.24**	**2.60%**	**26.47%**
Wholesale Market Service Rate	53,051	0.0036	190.98	53,051	0.0036	190.98	0.00	0.00%	2.55%
Rural Rate Protection Charge	53,051	0.0003	15.92	53,051	0.0003	15.92	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**207.15**			**207.15**	**0.00**	**0.00%**	**2.77%**
Debt Retirement Charge (DRC)	50,525	0.007	**353.68**	50,525	0.007	**353.68**	**0.00**	**0.00%**	**4.72%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,578.39**			**6,628.63**	**50.24**	**0.76%**	**88.50%**
HST		0.13	855.19		0.13	861.72	6.53	0.76%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,433.58**			**7,490.35**	**56.77**	**0.76%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,433.58**			**7,490.35**	**56.77**	**0.76%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.050
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	183,750	0.077	14,148.75	183,750	0.077	14,148.75	0.00	0.00%	54.07%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,148.75**			**14,148.75**	**0.00**	**0.00%**	**54.07%**
Service Charge	1	100.72	100.72	1	102.72	102.72	2.00	1.99%	0.39%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	9.6226	4,811.30	500	9.9799	4,989.95	178.65	3.71%	19.07%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0112	5.59	500	0.0112	5.59	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**4,917.63**			**5,098.28**	**180.65**	**3.67%**	**19.48%**
Retail Transmission Rate – Network Service Rate	500	2.23104	1,115.52	500	2.2310	1,115.52	0.00	0.00%	4.26%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.704675	852.34	500	1.7047	852.34	0.00	0.00%	3.26%
Sub-Total: Retail Transmission			**1,967.86**			**1,967.86**	**0.00**	**0.00%**	**7.52%**
Sub-Total: Delivery			**6,885.49**			**7,066.14**	**180.65**	**2.62%**	**27.00%**
Wholesale Market Service Rate	183,750	0.0036	661.50	183,750	0.0036	661.50	0.00	0.00%	2.53%
Rural Rate Protection Charge	183,750	0.0003	55.13	183,750	0.0003	55.13	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**716.88**			**716.88**	**0.00**	**0.00%**	**2.74%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.68%**
Total Electricity Charge on Two-Tier RPP (before HST)			**22,976.11**			**23,156.76**	**180.65**	**0.79%**	**88.50%**
HST		0.13	2,986.89		0.13	3,010.38	23.48	0.79%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**25,963.00**			**26,167.14**	**204.13**	**0.79%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**25,963.00**			**26,167.14**	**204.13**	**0.79%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.061
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,915
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,915	0.077	1,225.46	15,915	0.077	1,225.46	0.00	0.00%	39.91%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,225.46**			**1,225.46**	**0.00**	**0.00%**	**39.91%**
Service Charge	1	102.52	102.52	1	104.19	104.19	1.67	1.63%	3.39%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	16.7689	1,006.13	60	17.3874	1,043.24	37.11	3.69%	33.97%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0052	0.31	60	0.0052	0.31	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,108.95**			**1,147.73**	**38.78**	**3.50%**	**37.38%**
Retail Transmission Rate – Network Service Rate	60	1.6718177	100.31	60	1.6718	100.31	0.00	0.00%	3.27%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.2769135	76.61	60	1.2769	76.61	0.00	0.00%	2.50%
Sub-Total: Retail Transmission			**176.92**			**176.92**	**0.00**	**0.00%**	**5.76%**
Sub-Total: Delivery			**1,285.88**			**1,324.66**	**38.78**	**3.02%**	**43.14%**
Wholesale Market Service Rate	15,915	0.0036	57.29	15,915	0.0036	57.29	0.00	0.00%	1.87%
Rural Rate Protection Charge	15,915	0.0003	4.77	15,915	0.0003	4.77	0.00	0.00%	0.16%
Ontario Electricity Support Program Charge	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.32**			**62.32**	**0.00**	**0.00%**	**2.03%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.42%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,678.65**			**2,717.43**	**38.78**	**1.45%**	**88.50%**
HST		0.13	348.22		0.13	353.27	5.04	1.45%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**3,026.88**			**3,070.70**	**43.82**	**1.45%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**3,026.88**			**3,070.70**	**43.82**	**1.45%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	36,104
Peak (kW)	124
Loss factor	1.061
Load factor	40%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	38,306
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	38,306	0.077	2,949.59	38,306	0.077	2,949.59	0.00	0.00%	43.66%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**2,949.59**			**2,949.59**	**0.00**	**0.00%**	**43.66%**
Service Charge	1	102.52	102.52	1	104.19	104.19	1.67	1.63%	1.54%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	124	16.7689	2,079.34	124	17.3874	2,156.04	76.69	3.69%	31.91%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	124	0.0052	0.64	124	0.0052	0.64	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,182.49**			**2,260.86**	**78.36**	**3.59%**	**33.47%**
Retail Transmission Rate – Network Service Rate	124	1.6718177	207.31	124	1.6718	207.31	0.00	0.00%	3.07%
Retail Transmission Rate – Line and Transformation Connection Service Rate	124	1.2769135	158.34	124	1.2769	158.34	0.00	0.00%	2.34%
Sub-Total: Retail Transmission			**365.64**			**365.64**	**0.00**	**0.00%**	**5.41%**
Sub-Total: Delivery			**2,548.14**			**2,626.50**	**78.36**	**3.08%**	**38.88%**
Wholesale Market Service Rate	38,306	0.0036	137.90	38,306	0.0036	137.90	0.00	0.00%	2.04%
Rural Rate Protection Charge	38,306	0.0003	11.49	38,306	0.0003	11.49	0.00	0.00%	0.17%
Ontario Electricity Support Program Charge	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**149.64**			**149.64**	**0.00**	**0.00%**	**2.22%**
Debt Retirement Charge (DRC)	36,104	0.007	**252.73**	36,104	0.007	**252.73**	**0.00**	**0.00%**	**3.74%**
Total Electricity Charge on Two-Tier RPP (before HST)			**5,900.10**			**5,978.46**	**78.36**	**1.33%**	**88.50%**
HST		0.13	767.01		0.13	777.20	10.19	1.33%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**6,667.11**			**6,755.66**	**88.55**	**1.33%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**6,667.11**			**6,755.66**	**88.55**	**1.33%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.061
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	185,675
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	185,675	0.077	14,296.98	185,675	0.077	14,296.98	0.00	0.00%	47.71%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,296.98**			**14,296.98**	**0.00**	**0.00%**	**47.71%**
Service Charge	1	102.52	102.52	1	104.19	104.19	1.67	1.63%	0.35%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	16.7689	8,384.45	500	17.3874	8,693.70	309.25	3.69%	29.01%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0052	2.58	500	0.0052	2.58	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**8,489.54**			**8,800.46**	**310.92**	**3.66%**	**29.37%**
Retail Transmission Rate – Network Service Rate	500	1.6718177	835.91	500	1.6718	835.91	0.00	0.00%	2.79%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.2769135	638.46	500	1.2769	638.46	0.00	0.00%	2.13%
Sub-Total: Retail Transmission			**1,474.37**			**1,474.37**	**0.00**	**0.00%**	**4.92%**
Sub-Total: Delivery			**9,963.91**			**10,274.83**	**310.92**	**3.12%**	**34.28%**
Wholesale Market Service Rate	185,675	0.0036	668.43	185,675	0.0036	668.43	0.00	0.00%	2.23%
Rural Rate Protection Charge	185,675	0.0003	55.70	185,675	0.0003	55.70	0.00	0.00%	0.19%
Ontario Electricity Support Program Charge	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**724.38**			**724.38**	**0.00**	**0.00%**	**2.42%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.09%**
Total Electricity Charge on Two-Tier RPP (before HST)			**26,210.26**			**26,521.18**	**310.92**	**1.19%**	**88.50%**
HST		0.13	3,407.33		0.13	3,447.75	40.42	1.19%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**29,617.60**			**29,968.94**	**351.34**	**1.19%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**29,617.60**			**29,968.94**	**351.34**	**1.19%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	300
Peak (kW)	10
Loss factor	1.061
Load factor	4%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	318
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	318	0.077	24.51	318	0.077	24.51	0.00	0.00%	6.49%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**24.51**			**24.51**	**0.00**	**0.00%**	**6.49%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	51.93%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	10	6.431	64.31	10	9.8220	98.22	33.91	52.73%	26.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10	0.0028	0.03	10	0.0028	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**260.51**			**294.42**	**33.91**	**13.02%**	**77.94%**
Retail Transmission Rate – Network Service Rate	10	0.6311	6.31	10	0.6311	6.31	0.00	0.00%	1.67%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	0.5475	5.47	10	0.5475	5.47	0.00	0.00%	1.45%
Sub-Total: Retail Transmission			**11.79**			**11.79**	**0.00**	**0.00%**	**3.12%**
Sub-Total: Delivery			**272.29**			**306.20**	**33.91**	**12.45%**	**81.06%**
Wholesale Market Service Rate	318	0.0036	1.15	318	0.0036	1.15	0.00	0.00%	0.30%
Rural Rate Protection Charge	318	0.0003	0.10	318	0.0003	0.10	0.00	0.00%	0.03%
Ontario Electricity Support Program Charge	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%
Sub-Total: Regulatory			**1.49**			**1.49**	**0.00**	**0.00%**	**0.39%**
Debt Retirement Charge (DRC)	300	0.007	**2.10**	300	0.007	**2.10**	**0.00**	**0.00%**	**0.56%**
Total Electricity Charge on Two-Tier RPP (before HST)			**300.40**			**334.31**	**33.91**	**11.29%**	**88.50%**
HST		0.13	39.05		0.13	43.46	4.41	11.29%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**339.45**			**377.76**	**38.32**	**11.29%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**339.45**			**377.76**	**38.32**	**11.29%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	1,328
Peak (kW)	13
Loss factor	1.061
Load factor	14%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,409
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,409	0.077	108.49	1,409	0.077	108.49	0.00	0.00%	20.75%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**108.49**			**108.49**	**0.00**	**0.00%**	**20.75%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	37.51%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	13	6.431	83.60	13	9.8220	127.69	44.08	52.73%	24.42%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	13	0.0028	0.04	13	0.0028	0.04	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**279.81**			**323.89**	**44.08**	**15.75%**	**61.94%**
Retail Transmission Rate – Network Service Rate	13	0.6311	8.20	13	0.6311	8.20	0.00	0.00%	1.57%
Retail Transmission Rate – Line and Transformation Connection Service Rate	13	0.5475	7.12	13	0.5475	7.12	0.00	0.00%	1.36%
Sub-Total: Retail Transmission			**15.32**			**15.32**	**0.00**	**0.00%**	**2.93%**
Sub-Total: Delivery			**295.13**			**339.21**	**44.08**	**14.94%**	**64.87%**
Wholesale Market Service Rate	1,409	0.0036	5.07	1,409	0.0036	5.07	0.00	0.00%	0.97%
Rural Rate Protection Charge	1,409	0.0003	0.42	1,409	0.0003	0.42	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**5.75**			**5.75**	**0.00**	**0.00%**	**1.10%**
Debt Retirement Charge (DRC)	1,328	0.007	**9.30**	1,328	0.007	**9.30**	**0.00**	**0.00%**	**1.78%**
Total Electricity Charge on Two-Tier RPP (before HST)			**418.67**			**462.75**	**44.08**	**10.53%**	**88.50%**
HST		0.13	54.43		0.13	60.16	5.73	10.53%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**473.09**			**522.91**	**49.81**	**10.53%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**473.09**			**522.91**	**49.81**	**10.53%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	5,000
Peak (kW)	100
Loss factor	1.061
Load factor	7%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	5,305
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	5,305	0.077	408.49	5,305	0.077	408.49	0.00	0.00%	20.53%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**408.49**			**408.49**	**0.00**	**0.00%**	**20.53%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	9.86%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	6.431	643.10	100	9.8220	982.20	339.10	52.73%	49.36%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0028	0.28	100	0.0028	0.28	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**839.55**			**1,178.65**	**339.10**	**40.39%**	**59.23%**
Retail Transmission Rate – Network Service Rate	100	0.6311	63.11	100	0.6311	63.11	0.00	0.00%	3.17%
Retail Transmission Rate – Line and Transformation Connection Service Rate	100	0.5475	54.75	100	0.5475	54.75	0.00	0.00%	2.75%
Sub-Total: Retail Transmission			**117.86**			**117.86**	**0.00**	**0.00%**	**5.92%**
Sub-Total: Delivery			**957.41**			**1,296.51**	**339.10**	**35.42%**	**65.16%**
Wholesale Market Service Rate	5,305	0.0036	19.10	5,305	0.0036	19.10	0.00	0.00%	0.96%
Rural Rate Protection Charge	5,305	0.0003	1.59	5,305	0.0003	1.59	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**20.94**			**20.94**	**0.00**	**0.00%**	**1.05%**
Debt Retirement Charge (DRC)	5,000	0.007	**35.00**	5,000	0.007	**35.00**	**0.00**	**0.00%**	**1.76%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,421.83**			**1,760.93**	**339.10**	**23.85%**	**88.50%**
HST		0.13	184.84		0.13	228.92	44.08	23.85%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**1,606.67**			**1,989.85**	**383.18**	**23.85%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**1,606.67**			**1,989.85**	**383.18**	**23.85%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	200,000
Peak (kW)	500
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	206,800
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	206,800	0.077	15,923.60	206,800	0.077	15,923.60	0.00	0.00%	61.22%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15,923.60**			**15,923.60**	**0.00**	**0.00%**	**61.22%**
Service Charge	1	1199.21	1,199.21	1	1223.97	1,223.97	24.76	2.06%	4.71%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.01%
Distribution Volumetric Rate	500	1.3103	655.13	500	1.3658	682.92	27.79	4.24%	2.63%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	-0.1367	-68.34	500	-0.1367	-68.34	0.00	0.00%	-0.26%
Volumetric Global Adjustment Account Rider	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**1,789.82**			**1,842.38**	**52.55**	**2.94%**	**7.08%**
Retail Transmission Rate – Network Service Rate	500	3.4866	1,743.32	500	3.4866	1,743.32	0.00	0.00%	6.70%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.6022	1,301.08	500	2.6022	1,301.08	0.00	0.00%	5.00%
Sub-Total: Retail Transmission			**3,044.41**			**3,044.41**	**0.00**	**0.00%**	**11.71%**
Sub-Total: Delivery			**4,834.23**			**4,886.78**	**52.55**	**1.09%**	**18.79%**
Wholesale Market Service Rate	206,800	0.0036	744.48	206,800	0.0036	744.48	0.00	0.00%	2.86%
Rural Rate Protection Charge	206,800	0.0003	62.04	206,800	0.0003	62.04	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**806.77**			**806.77**	**0.00**	**0.00%**	**3.10%**
Debt Retirement Charge (DRC)	200,000	0.007	**1,400.00**	200,000	0.007	**1,400.00**	**0.00**	**0.00%**	**5.38%**
Total Electricity Charge on Two-Tier RPP (before HST)			**22,964.60**			**23,017.15**	**52.55**	**0.23%**	**88.50%**
HST		0.13	2,985.40		0.13	2,992.23	6.83	0.23%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**25,950.00**			**26,009.38**	**59.39**	**0.23%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**25,950.00**			**26,009.38**	**59.39**	**0.23%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	1,601,036
Peak (kW)	3,091
Loss factor	1.034
Load factor	71%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,655,471
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,655,471	0.077	127,471.28	1,655,471	0.077	127,471.28	0.00	0.00%	66.76%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**127,471.28**			**127,471.28**	**0.00**	**0.00%**	**66.76%**
Service Charge	1	1199.21	1,199.21	1	1223.97	1,223.97	24.76	2.06%	0.64%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	3,091	1.3103	4,050.01	3,091	1.3658	4,221.84	171.83	4.24%	2.21%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	3,091	-0.1367	-422.45	3,091	-0.1367	-422.45	0.00	0.00%	-0.22%
Volumetric Global Adjustment Account Rider	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**4,830.59**			**5,027.18**	**196.59**	**4.07%**	**2.63%**
Retail Transmission Rate – Network Service Rate	3,091	3.4866	10,777.23	3,091	3.4866	10,777.23	0.00	0.00%	5.64%
Retail Transmission Rate – Line and Transformation Connection Service Rate	3,091	2.6022	8,043.29	3,091	2.6022	8,043.29	0.00	0.00%	4.21%
Sub-Total: Retail Transmission			**18,820.52**			**18,820.52**	**0.00**	**0.00%**	**9.86%**
Sub-Total: Delivery			**23,651.11**			**23,847.70**	**196.59**	**0.83%**	**12.49%**
Wholesale Market Service Rate	1,655,471	0.0036	5,959.70	1,655,471	0.0036	5,959.70	0.00	0.00%	3.12%
Rural Rate Protection Charge	1,655,471	0.0003	496.64	1,655,471	0.0003	496.64	0.00	0.00%	0.26%
Ontario Electricity Support Program Charge	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**6,456.59**			**6,456.59**	**0.00**	**0.00%**	**3.38%**
Debt Retirement Charge (DRC)	1,601,036	0.007	**11,207.25**	1,601,036	0.007	**11,207.25**	**0.00**	**0.00%**	**5.87%**
Total Electricity Charge on Two-Tier RPP (before HST)			**168,786.23**			**168,982.82**	**196.59**	**0.12%**	**88.50%**
HST		0.13	21,942.21		0.13	21,967.77	25.56	0.12%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**190,728.44**			**190,950.59**	**222.15**	**0.12%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**190,728.44**			**190,950.59**	**222.15**	**0.12%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	4,000,000
Peak (kW)	10,000
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	4,136,000
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	4,136,000	0.077	318,472.00	4,136,000	0.077	318,472.00	0.00	0.00%	64.49%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**318,472.00**			**318,472.00**	**0.00**	**0.00%**	**64.49%**
Service Charge	1	1199.21	1,199.21	1	1223.97	1,223.97	24.76	2.06%	0.25%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	10,000	1.3103	13,102.59	10,000	1.3658	13,658.48	555.90	4.24%	2.77%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10,000	-0.1367	-1,366.70	10,000	-0.1367	-1,366.70	0.00	0.00%	-0.28%
Volumetric Global Adjustment Account Rider	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**12,938.91**			**13,519.57**	**580.66**	**4.49%**	**2.74%**
Retail Transmission Rate – Network Service Rate	10,000	3.4866	34,866.48	10,000	3.4866	34,866.48	0.00	0.00%	7.06%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10,000	2.6022	26,021.64	10,000	2.6022	26,021.64	0.00	0.00%	5.27%
Sub-Total: Retail Transmission			**60,888.12**			**60,888.12**	**0.00**	**0.00%**	**12.33%**
Sub-Total: Delivery			**73,827.04**			**74,407.70**	**580.66**	**0.79%**	**15.07%**
Wholesale Market Service Rate	4,136,000	0.0036	14,889.60	4,136,000	0.0036	14,889.60	0.00	0.00%	3.02%
Rural Rate Protection Charge	4,136,000	0.0003	1,240.80	4,136,000	0.0003	1,240.80	0.00	0.00%	0.25%
Ontario Electricity Support Program Charge	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**16,130.65**			**16,130.65**	**0.00**	**0.00%**	**3.27%**
Debt Retirement Charge (DRC)	4,000,000	0.007	**28,000.00**	4,000,000	0.007	**28,000.00**	**0.00**	**0.00%**	**5.67%**
Total Electricity Charge on Two-Tier RPP (before HST)			**436,429.69**			**437,010.35**	**580.66**	**0.13%**	**88.50%**
HST		0.13	56,735.86		0.13	56,811.35	75.49	0.13%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**493,165.55**			**493,821.69**	**656.15**	**0.13%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**493,165.55**			**493,821.69**	**656.15**	**0.13%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	14.93%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**14.93%**
Service Charge	1	34.76	34.76	1	35.49	35.49	0.73	2.10%	68.81%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	0.0284	2.84	100	0.0291	2.91	0.07	2.46%	5.64%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**37.60**			**38.40**	**0.80**	**2.13%**	**74.46%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	1.37%
Sub-Total: Distribution			**38.31**			**39.11**	**0.80**	**2.09%**	**75.83%**
Retail Transmission Rate – Network Service Rate	109	0.00477	0.52	109	0.0048	0.52	0.00	0.00%	1.01%
Retail Transmission Rate – Line and Transformation Connection S	109	0.003795	0.41	109	0.0038	0.41	0.00	0.00%	0.80%
Sub-Total: Retail Transmission			**0.94**			**0.94**	**0.00**	**0.00%**	**1.81%**
Sub-Total: Delivery			**39.25**			**40.05**	**0.80**	**2.04%**	**77.64%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	0.76%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.06%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.48%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**1.31%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**1.36%**
Total Electricity Charge on Two-Tier RPP (before HST)			**48.32**			**49.12**	**0.80**	**1.66%**	**95.24%**
HST		0.13	6.28		0.13	6.39	0.10	1.66%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**54.61**			**55.51**	**0.90**	**1.66%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.87		-0.08	-3.93	-0.06	-1.66%	-7.62%
Total Amount on Two-Tier RPP			**50.74**			**51.58**	**0.84**	**1.66%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	364
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	397
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	364	0.077	28.03	364	0.077	28.03	0.00	0.00%	31.61%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**28.03**			**28.03**	**0.00**	**0.00%**	**31.61%**
Service Charge	1	34.76	34.76	1	35.49	35.49	0.73	2.10%	40.02%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	364	0.0284	10.34	364	0.0291	10.59	0.25	2.46%	11.95%
Volumetric Deferral/Variance Account Rider (including CBR Class	364	0.0000	0.01	364	0.0000	0.01	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**45.11**			**46.09**	**0.98**	**2.18%**	**51.98%**
Line Losses on Cost of Power	33	0.0770	2.58	33	0.0770	2.58	0.00	0.00%	2.91%
Sub-Total: Distribution			**47.69**			**48.67**	**0.98**	**2.07%**	**54.89%**
Retail Transmission Rate – Network Service Rate	397	0.00477	1.90	397	0.0048	1.90	0.00	0.00%	2.14%
Retail Transmission Rate – Line and Transformation Connection S	397	0.003795	1.51	397	0.0038	1.51	0.00	0.00%	1.70%
Sub-Total: Retail Transmission			**3.40**			**3.40**	**0.00**	**0.00%**	**3.84%**
Sub-Total: Delivery			**51.09**			**52.07**	**0.98**	**1.93%**	**58.73%**
Wholesale Market Service Rate	397	0.0036	1.43	397	0.0036	1.43	0.00	0.00%	1.61%
Rural Rate Protection Charge	397	0.0003	0.12	397	0.0003	0.12	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%
Sub-Total: Regulatory			**1.80**			**1.80**	**0.00**	**0.00%**	**2.03%**
Debt Retirement Charge (DRC)	364	0.007	**2.55**	364	0.007	**2.55**	**0.00**	**0.00%**	**2.87%**
Total Electricity Charge on Two-Tier RPP (before HST)			**83.47**			**84.45**	**0.98**	**1.18%**	**95.24%**
HST		0.13	10.85		0.13	10.98	0.13	1.18%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**94.32**			**95.43**	**1.11**	**1.18%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.68		-0.08	-6.76	-0.08	-1.18%	-7.62%
Total Amount on Two-Tier RPP			**87.64**			**88.67**	**1.03**	**1.18%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1092
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	31.61%
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.32%
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**43.92%**
Service Charge	1	34.76	34.76	1	35.49	35.49	0.73	2.10%	19.42%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0284	28.40	1,000	0.0291	29.10	0.70	2.46%	15.93%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.02	1,000	0.0000	0.02	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**63.18**			**64.61**	**1.43**	**2.26%**	**35.36%**
Line Losses on Cost of Power	92	0.0900	8.28	92	0.0900	8.28	0.00	0.00%	4.53%
Sub-Total: Distribution			**71.46**			**72.89**	**1.43**	**2.00%**	**39.90%**
Retail Transmission Rate – Network Service Rate	1,092	0.00477	5.21	1,092	0.0048	5.21	0.00	0.00%	2.85%
Retail Transmission Rate – Line and Transformation Connection S	1,092	0.003795	4.14	1,092	0.0038	4.14	0.00	0.00%	2.27%
Sub-Total: Retail Transmission			**9.35**			**9.35**	**0.00**	**0.00%**	**5.12%**
Sub-Total: Delivery			**80.81**			**82.24**	**1.43**	**1.77%**	**45.02%**
Wholesale Market Service Rate	1,092	0.0036	3.93	1,092	0.0036	3.93	0.00	0.00%	2.15%
Rural Rate Protection Charge	1,092	0.0003	0.33	1,092	0.0003	0.33	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%
Sub-Total: Regulatory			**4.51**			**4.51**	**0.00**	**0.00%**	**2.47%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.83%**
Total Electricity Charge on Two-Tier RPP (before HST)			**172.57**			**174.00**	**1.43**	**0.83%**	**95.24%**
HST		0.13	22.43		0.13	22.62	0.19	0.83%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**195.01**			**196.62**	**1.62**	**0.83%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.81		-0.08	-13.92	-0.11	-0.83%	-7.62%
Total Amount on Two-Tier RPP			**181.20**			**182.70**	**1.50**	**0.83%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	20
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	21.84
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	20	0.077	1.54	20	0.077	1.54	0.00	0.00%	17.69%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1.54**			**1.54**	**0.00**	**0.00%**	**17.69%**
Service Charge	1	3.15	3.15	1	3.37	3.37	0.22	6.98%	38.72%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.07%
Distribution Volumetric Rate	20	0.1199	2.40	20	0.1281	2.56	0.16	6.84%	29.43%
Volumetric Deferral/Variance Account Rider (including CBR Class	20	-0.0001	0.00	20	-0.0001	0.00	0.00	0.00%	-0.01%
Sub-Total: Distribution (excluding pass through)			**5.55**			**5.94**	**0.38**	**6.92%**	**68.20%**
Line Losses on Cost of Power	2	0.0770	0.14	2	0.0770	0.14	0.00	0.00%	1.63%
Sub-Total: Distribution			**5.69**			**6.08**	**0.38**	**6.74%**	**69.83%**
Retail Transmission Rate – Network Service Rate	22	0.0047	0.10	22	0.0047	0.10	0.00	0.00%	1.18%
Retail Transmission Rate – Line and Transformation Connection S	22	0.0043	0.09	22	0.0043	0.09	0.00	0.00%	1.08%
Sub-Total: Retail Transmission			**0.20**			**0.20**	**0.00**	**0.00%**	**2.26%**
Sub-Total: Delivery			**5.89**			**6.27**	**0.38**	**6.52%**	**72.09%**
Wholesale Market Service Rate	22	0.0036	0.08	22	0.0036	0.08	0.00	0.00%	0.90%
Rural Rate Protection Charge	22	0.0003	0.01	22	0.0003	0.01	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	22	0.0000	0.00	22	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	2.87%
Sub-Total: Regulatory			**0.34**			**0.34**	**0.00**	**0.00%**	**3.85%**
Debt Retirement Charge (DRC)	20	0.007	**0.14**	20	0.007	**0.14**	**0.00**	**0.00%**	**1.61%**
Total Electricity Charge on Two-Tier RPP (before HST)			**7.91**			**8.29**	**0.38**	**4.86%**	**95.24%**
HST		0.13	1.03		0.13	1.08	0.05	4.86%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**8.93**			**9.37**	**0.43**	**4.86%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-0.63		-0.08	-0.66	-0.03	-4.86%	-7.62%
Total Amount on Two-Tier RPP			**8.30**			**8.70**	**0.40**	**4.86%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	71
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	78
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	71	0.077	5.47	71	0.077	5.47	0.00	0.00%	25.80%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**5.47**			**5.47**	**0.00**	**0.00%**	**25.80%**
Service Charge	1	3.15	3.15	1	3.37	3.37	0.22	6.98%	15.90%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	71	0.1199	8.51	71	0.1281	9.10	0.58	6.84%	42.92%
Volumetric Deferral/Variance Account Rider (including CBR Class	71	-0.0001	0.00	71	-0.0001	0.00	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**11.66**			**12.47**	**0.80**	**6.88%**	**58.83%**
Line Losses on Cost of Power	7	0.0770	0.50	7	0.0770	0.50	0.00	0.00%	2.37%
Sub-Total: Distribution			**12.17**			**12.97**	**0.80**	**6.59%**	**61.20%**
Retail Transmission Rate – Network Service Rate	78	0.0047	0.36	78	0.0047	0.36	0.00	0.00%	1.72%
Retail Transmission Rate – Line and Transformation Connection S	78	0.0043	0.33	78	0.0043	0.33	0.00	0.00%	1.57%
Sub-Total: Retail Transmission			**0.70**			**0.70**	**0.00**	**0.00%**	**3.29%**
Sub-Total: Delivery			**12.86**			**13.67**	**0.80**	**6.24%**	**64.49%**
Wholesale Market Service Rate	78	0.0036	0.28	78	0.0036	0.28	0.00	0.00%	1.32%
Rural Rate Protection Charge	78	0.0003	0.02	78	0.0003	0.02	0.00	0.00%	0.11%
Ontario Electricity Support Program Charge	78	0.0000	0.00	78	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.18%
Sub-Total: Regulatory			**0.55**			**0.55**	**0.00**	**0.00%**	**2.61%**
Debt Retirement Charge (DRC)	71	0.007	**0.50**	71	0.007	**0.50**	**0.00**	**0.00%**	**2.35%**
Total Electricity Charge on Two-Tier RPP (before HST)			**19.38**			**20.18**	**0.80**	**4.14%**	**95.24%**
HST		0.13	2.52		0.13	2.62	0.10	4.14%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**21.90**			**22.81**	**0.91**	**4.14%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.55		-0.08	-1.61	-0.06	-4.14%	-7.62%
Total Amount on Two-Tier RPP			**20.35**			**21.19**	**0.84**	**4.14%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	200
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	218.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	200	0.077	15.40	200	0.077	15.40	0.00	0.00%	29.18%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15.40**			**15.40**	**0.00**	**0.00%**	**29.18%**
Service Charge	1	3.15	3.15	1	3.37	3.37	0.22	6.98%	6.39%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	200	0.1199	23.98	200	0.1281	25.62	1.64	6.84%	48.54%
Volumetric Deferral/Variance Account Rider (including CBR Class	200	-0.0001	-0.01	200	-0.0001	-0.01	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**27.12**			**28.98**	**1.86**	**6.86%**	**54.92%**
Line Losses on Cost of Power	18	0.0770	1.42	18	0.0770	1.42	0.00	0.00%	2.68%
Sub-Total: Distribution			**28.54**			**30.40**	**1.86**	**6.52%**	**57.60%**
Retail Transmission Rate – Network Service Rate	218	0.0047	1.03	218	0.0047	1.03	0.00	0.00%	1.94%
Retail Transmission Rate – Line and Transformation Connection S	218	0.0043	0.94	218	0.0043	0.94	0.00	0.00%	1.78%
Sub-Total: Retail Transmission			**1.96**			**1.96**	**0.00**	**0.00%**	**3.72%**
Sub-Total: Delivery			**30.50**			**32.36**	**1.86**	**6.10%**	**61.32%**
Wholesale Market Service Rate	218	0.0036	0.79	218	0.0036	0.79	0.00	0.00%	1.49%
Rural Rate Protection Charge	218	0.0003	0.07	218	0.0003	0.07	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	218	0.0000	0.00	218	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.47%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	**0.00%**	**2.09%**
Debt Retirement Charge (DRC)	200	0.007	**1.40**	200	0.007	**1.40**	**0.00**	**0.00%**	**2.65%**
Total Electricity Charge on Two-Tier RPP (before HST)			**48.41**			**50.27**	**1.86**	**3.84%**	**95.24%**
HST		0.13	6.29		0.13	6.53	0.24	3.84%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**54.70**			**56.80**	**2.10**	**3.84%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.87		-0.08	-4.02	-0.15	-3.84%	-7.62%
Total Amount on Two-Tier RPP			**50.83**			**52.78**	**1.95**	**3.84%**	**100.00%**

2019 Bill Impacts (Low Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	29.24%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**29.24%**
Service Charge	1	4.07	4.07	1	4.2	4.20	0.13	3.19%	15.95%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	100	0.0976	9.76	100	0.1011	10.11	0.35	3.59%	38.39%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**13.84**			**14.32**	**0.48**	**3.47%**	**54.36%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	2.69%
Sub-Total: Distribution			**14.54**			**15.02**	**0.48**	**3.30%**	**57.05%**
Retail Transmission Rate – Network Service Rate	109	0.004698	0.51	109	0.0047	0.51	0.00	0.00%	1.95%
Retail Transmission Rate – Line and Transformation Connection S	109	0.00429	0.47	109	0.0043	0.47	0.00	0.00%	1.78%
Sub-Total: Retail Transmission			**0.98**			**0.98**	**0.00**	**0.00%**	**3.73%**
Sub-Total: Delivery			**15.53**			**16.01**	**0.48**	**3.09%**	**60.78%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	1.49%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.95%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**2.57%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**2.66%**
Total Electricity Charge on Two-Tier RPP (before HST)			**24.60**			**25.08**	**0.48**	**1.95%**	**95.24%**
HST		0.13	3.20		0.13	3.26	0.06	1.95%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**27.80**			**28.34**	**0.54**	**1.95%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.97		-0.08	-2.01	-0.04	-1.95%	-7.62%
Total Amount on Two-Tier RPP			**25.83**			**26.34**	**0.50**	**1.95%**	**100.00%**

2019 Bill Impacts (Typical Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	517
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	565
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	517	0.077	39.81	517	0.077	39.81	0.00	0.00%	34.13%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**39.81**			**39.81**	**0.00**	**0.00%**	**34.13%**
Service Charge	1	4.07	4.07	1	4.2	4.20	0.13	3.19%	3.60%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	517	0.0976	50.46	517	0.1011	52.27	1.81	3.59%	44.81%
Volumetric Deferral/Variance Account Rider (including CBR Class	517	0.0000	-0.01	517	0.0000	-0.01	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**54.53**			**56.47**	**1.94**	**3.56%**	**48.41%**
Line Losses on Cost of Power	48	0.0770	3.66	48	0.0770	3.66	0.00	0.00%	3.14%
Sub-Total: Distribution			**58.19**			**60.13**	**1.94**	**3.33%**	**51.55%**
Retail Transmission Rate – Network Service Rate	565	0.004698	2.65	565	0.0047	2.65	0.00	0.00%	2.27%
Retail Transmission Rate – Line and Transformation Connection S	565	0.00429	2.42	565	0.0043	2.42	0.00	0.00%	2.08%
Sub-Total: Retail Transmission			**5.07**			**5.07**	**0.00**	**0.00%**	**4.35%**
Sub-Total: Delivery			**63.27**			**65.21**	**1.94**	**3.07%**	**55.90%**
Wholesale Market Service Rate	565	0.0036	2.03	565	0.0036	2.03	0.00	0.00%	1.74%
Rural Rate Protection Charge	565	0.0003	0.17	565	0.0003	0.17	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	565	0.0000	0.00	565	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%
Sub-Total: Regulatory			**2.45**			**2.45**	**0.00**	**0.00%**	**2.10%**
Debt Retirement Charge (DRC)	517	0.007	**3.62**	517	0.007	**3.62**	**0.00**	**0.00%**	**3.10%**
Total Electricity Charge on Two-Tier RPP (before HST)			**109.15**			**111.09**	**1.94**	**1.78%**	**95.24%**
HST		0.13	14.19		0.13	14.44	0.25	1.78%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**123.34**			**125.53**	**2.19**	**1.78%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.73		-0.08	-8.89	-0.16	-1.78%	-7.62%
Total Amount on Two-Tier RPP			**114.60**			**116.64**	**2.04**	**1.78%**	**100.00%**

2019 Bill Impacts (High Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2184
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.63%
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	24.60%
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**37.22%**
Service Charge	1	4.07	4.07	1	4.2	4.20	0.13	3.19%	0.92%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0976	195.20	2,000	0.1011	202.20	7.00	3.59%	44.21%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	-0.02	2,000	0.0000	-0.02	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**199.26**			**206.39**	**7.13**	**3.58%**	**45.12%**
Line Losses on Cost of Power	184	0.0900	16.56	184	0.0900	16.56	0.00	0.00%	3.62%
Sub-Total: Distribution			**215.82**			**222.95**	**7.13**	**3.30%**	**48.74%**
Retail Transmission Rate – Network Service Rate	2,184	0.004698	10.26	2,184	0.0047	10.26	0.00	0.00%	2.24%
Retail Transmission Rate – Line and Transformation Connection S	2,184	0.00429	9.37	2,184	0.0043	9.37	0.00	0.00%	2.05%
Sub-Total: Retail Transmission			**19.63**			**19.63**	**0.00**	**0.00%**	**4.29%**
Sub-Total: Delivery			**235.45**			**242.58**	**7.13**	**3.03%**	**53.04%**
Wholesale Market Service Rate	2,184	0.0036	7.86	2,184	0.0036	7.86	0.00	0.00%	1.72%
Rural Rate Protection Charge	2,184	0.0003	0.66	2,184	0.0003	0.66	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	2,184	0.0000	0.00	2,184	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**8.77**			**8.77**	**0.00**	**0.00%**	**1.92%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.06%**
Total Electricity Charge on Two-Tier RPP (before HST)			**428.46**			**435.59**	**7.13**	**1.66%**	**95.24%**
HST		0.13	55.70		0.13	56.63	0.93	1.66%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**484.16**			**492.22**	**8.06**	**1.66%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-34.28		-0.08	-34.85	-0.57	-1.66%	-7.62%
Total Amount on Two-Tier RPP			**449.89**			**457.37**	**7.49**	**1.66%**	**100.00%**

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2019 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$74.60	$2.97	9.04%	$3.12	4.19%
	Typical	750		$121.13	$1.10	3.15%	$1.15	0.95%
	Average	755		$121.71	$1.07	3.08%	$1.13	0.92%
	High	1,400		$196.73	($1.96)	-5.18%	($2.06)	-1.05%
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%
Seasonal	Low	50		$56.78	$4.54	9.51%	$4.76	8.39%
	Average	352		$107.32	$1.85	2.90%	$1.94	1.81%
	High	1,000		$215.77	($3.92)	-4.00%	($4.12)	-1.91%
GSe	Low	1,000		$215.28	$2.68	2.93%	$2.81	1.31%
	Typical	2,000		$397.75	$4.68	3.06%	$4.91	1.24%
	Average	1,982		$394.47	$4.64	3.06%	$4.88	1.24%
	High	15,000		$2,769.91	$30.68	3.23%	$32.21	1.16%
UGe	Low	1,000		$173.10	$1.53	2.86%	$1.61	0.93%
	Typical	2,000		$319.40	$2.43	2.94%	$2.55	0.80%
	Average	2,759		$430.44	$3.11	2.98%	$3.27	0.76%
	High	15,000		$2,221.32	$14.13	3.07%	$14.84	0.67%
GSd	Low	15,000	60	$3,070.67	$34.71	3.02%	$39.22	1.28%
	Average	36,104	124	$6,755.61	$69.59	3.08%	$78.64	1.16%
	High	175,000	500	$29,968.71	$274.55	3.12%	$310.24	1.04%
UGd	Low	15,000	60	$2,619.08	$21.10	3.00%	$23.84	0.91%
	Average	50,525	135	$7,490.35	$44.60	3.07%	$50.39	0.67%
	High	175,000	500	$26,167.14	$158.95	3.12%	$179.61	0.69%
St Lgt	Low	100		$26.34	$0.45	3.14%	$0.47	1.79%
	Average	517		$116.64	$1.78	3.16%	$1.87	1.61%
	High	2,000		$457.37	$6.53	3.16%	$6.86	1.50%
Sen Lgt	Low	20		$8.70	$0.35	5.83%	$0.36	4.17%
	Average	71		$21.19	$0.72	5.76%	$0.75	3.56%
	High	200		$52.78	$1.66	5.73%	$1.74	3.30%
USL	Low	100		$51.58	$1.24	3.23%	$1.30	2.52%
	Average	364		$88.67	$1.42	3.09%	$1.50	1.69%
	High	1,000		$182.70	$1.87	2.89%	$1.96	1.07%
DGen	Low	300	10	$377.76	$8.23	2.79%	$9.30	2.46%
	Average	1,328	13	$522.91	$10.69	3.30%	$12.08	2.31%
	High	5,000	100	$1,989.85	$82.26	6.98%	$92.95	4.67%
ST	Low	200,000	500	$26,009.38	$55.86	3.03%	$63.13	0.24%
	Average	1,601,036	3,091	$190,950.59	$179.74	3.58%	$203.10	0.11%
	High	4,000,000	10,000	$493,821.69	$510.04	3.77%	$576.35	0.12%

2020 Bill Impacts (Low Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	370
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	35.59%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**35.59%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		19.03%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.27%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		10.70%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**37.98%**	**37.00%**
Service Charge	1	31.23	31.23	1	35.85	35.85	4.62	14.79%	47.35%	46.12%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	350	0.0047	1.65	350	0.0000	0.00	-1.65	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	350	0.0000	0.01	350	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**32.89**			**35.87**	**2.97**	**9.04%**	**47.37%**	**46.15%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.04%	1.02%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	2.03%	1.98%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.16%	2.11%
Sub-Total: Distribution (based on two-tier RPP prices)			**35.22**			**38.19**	**2.97**	**8.45%**	**50.44%**	**49.14%**
Sub-Total: Distribution (based on TOU prices)			**35.32**			**38.30**	**2.97**	**8.42%**	**50.58%**	**49.27%**
Retail Transmission Rate – Network Service Rate	370	0.0078	2.90	370	0.0078	2.90	0.00	0.00%	3.82%	3.73%
Retail Transmission Rate – Line and Transformation Connection Service Rate	370	0.0064	2.38	370	0.0064	2.38	0.00	0.00%	3.15%	3.06%
Sub-Total: Retail Transmission			**5.28**			**5.28**	**0.00**	**0.00%**	**6.97%**	**6.79%**
Sub-Total: Delivery (based on two-tier RPP prices)			**40.50**			**43.47**	**2.97**	**7.35%**	**57.41%**	**55.93%**
Sub-Total: Delivery (based on TOU prices)			**40.60**			**43.57**	**2.97**	**7.33%**	**57.55%**	**56.06%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.76%	1.71%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.15%	0.14%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.33%	0.32%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.24%**	**2.18%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**69.14**			**72.11**	**2.97**	**4.30%**	**95.24%**	
HST		0.13	8.99		0.13	9.37	0.39	4.30%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**78.13**			**81.49**	**3.36**	**4.30%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.53		-0.08	-5.77	-0.24	-4.30%	-7.62%	
Total Amount on Two-Tier RPP			**72.60**			**75.72**	**3.12**	**4.30%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**71.05**			**74.02**	**2.97**	**4.19%**		**95.24%**
HST		0.13	9.24		0.13	9.62	0.39	4.19%		12.38%
Total Electricity Charge on TOU (including HST)			**80.28**			**83.65**	**3.36**	**4.19%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.68		-0.08	-5.92	-0.24	-4.19%		-7.62%
Total Amount on TOU			**74.60**			**77.72**	**3.12**	**4.19%**		**100.00%**

2020 Bill Impacts (Typical Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	793
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.30%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.19%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**49.50%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.91%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.91%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.57%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**51.09%**	**50.39%**
Service Charge	1	31.23	31.23	1	35.85	35.85	4.62	14.79%	29.72%	29.32%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	750	0.0047	3.53	750	0.0000	0.00	-3.53	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**34.78**			**35.88**	**1.10**	**3.15%**	**29.75%**	**29.34%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.65%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.19%	3.15%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	2.91%	2.87%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.42**			**40.52**	**1.10**	**2.78%**	**33.59%**	**33.14%**
Sub-Total: Distribution (based on TOU prices)			**39.09**			**40.18**	**1.10**	**2.80%**	**33.32%**	**32.86%**
Retail Transmission Rate – Network Service Rate	793	0.0078	6.21	793	0.0078	6.21	0.00	0.00%	5.15%	5.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate	793	0.0064	5.10	793	0.0064	5.10	0.00	0.00%	4.23%	4.17%
Sub-Total: Retail Transmission			**11.31**			**11.31**	**0.00**	**0.00%**	**9.38%**	**9.25%**
Sub-Total: Delivery (based on two-tier RPP prices)			**50.73**			**51.83**	**1.10**	**2.16%**	**42.97%**	**42.38%**
Sub-Total: Delivery (based on TOU prices)			**50.40**			**51.49**	**1.10**	**2.17%**	**42.69%**	**42.11%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.37%	2.33%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.20%	0.19%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.77%**	**2.73%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**113.77**			**114.87**	**1.10**	**0.96%**	**95.24%**	
HST		0.13	14.79		0.13	14.93	0.14	0.96%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**128.56**			**129.80**	**1.24**	**0.96%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.10		-0.08	-9.19	-0.09	-0.96%	-7.62%	
Total Amount on Two-Tier RPP			**119.46**			**120.61**	**1.15**	**0.96%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**115.36**			**116.45**	**1.10**	**0.95%**		**95.24%**
HST		0.13	15.00		0.13	15.14	0.14	0.95%		12.38%
Total Electricity Charge on TOU (including HST)			**130.35**			**131.59**	**1.24**	**0.95%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.23		-0.08	-9.32	-0.09	-0.95%		-7.62%
Total Amount on TOU			**121.13**			**122.28**	**1.15**	**0.95%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	755
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	798
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.12%	
Energy Second Tier (kWh)	155	0.090	13.95	155	0.090	13.95	0.00	0.00%	11.51%	
Sub-Total: Energy (RPP)			**60.15**			**60.15**	**0.00**	**0.00%**	**49.62%**	
TOU-Off Peak	491	0.065	31.90	491	0.065	31.90	0.00	0.00%		25.97%
TOU-Mid Peak	128	0.095	12.19	128	0.095	12.19	0.00	0.00%		9.93%
TOU-On Peak	136	0.132	17.94	136	0.132	17.94	0.00	0.00%		14.60%
Sub-Total: Energy (TOU)			**62.03**			**62.03**	0.00	0.00%	**51.18%**	**50.50%**
Service Charge	1	31.23	31.23	1	35.85	35.85	4.62	14.79%	29.58%	29.19%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	755	0.0047	3.55	755	0.0000	0.00	-3.55	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	755	0.0000	0.02	755	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**34.81**			**35.88**	**1.07**	**3.08%**	**29.60%**	**29.21%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.87	43	0.0900	3.87	0.00	0.00%	3.20%	3.15%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	43	0.0822	3.54	0.00	0.00%	2.92%	2.88%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.47**			**40.54**	**1.07**	**2.71%**	**33.45%**	**33.01%**
Sub-Total: Distribution (based on TOU prices)			**39.13**			**40.21**	**1.07**	**2.74%**	**33.17%**	**32.73%**
Retail Transmission Rate – Network Service Rate	798	0.0078	6.25	798	0.0078	6.25	0.00	0.00%	5.15%	5.09%
Retail Transmission Rate – Line and Transformation Connection Service Rate	798	0.0064	5.14	798	0.0064	5.14	0.00	0.00%	4.24%	4.18%
Sub-Total: Retail Transmission			**11.38**			**11.38**	**0.00**	**0.00%**	**9.39%**	**9.27%**
Sub-Total: Delivery (based on two-tier RPP prices)			**50.86**			**51.93**	**1.07**	**2.11%**	**42.84%**	**42.28%**
Sub-Total: Delivery (based on TOU prices)			**50.52**			**51.59**	**1.07**	**2.12%**	**42.56%**	**42.00%**
Wholesale Market Service Rate	798	0.0036	2.87	798	0.0036	2.87	0.00	0.00%	2.37%	2.34%
Rural Rate Protection Charge	798	0.0003	0.24	798	0.0003	0.24	0.00	0.00%	0.20%	0.19%
Ontario Electricity Support Program Charge	798	0.0000	0.00	798	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.36**			**3.36**	**0.00**	**0.00%**	**2.77%**	**2.74%**
Debt Retirement Charge (DRC)	755	0.000	**0.00**	755	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**114.37**			**115.44**	**1.07**	**0.94%**	**95.24%**	
HST		0.13	14.87		0.13	15.01	0.14	0.94%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**129.24**			**130.45**	**1.21**	**0.94%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.15		-0.08	-9.24	-0.09	-0.94%	-7.62%	
Total Amount on Two-Tier RPP			**120.09**			**121.21**	**1.13**	**0.94%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**115.91**			**116.98**	**1.07**	**0.92%**		**95.24%**
HST		0.13	15.07		0.13	15.21	0.14	0.92%		12.38%
Total Electricity Charge on TOU (including HST)			**130.98**			**132.19**	**1.21**	**0.92%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.27		-0.08	-9.36	-0.09	-0.92%		-7.62%
Total Amount on TOU			**121.71**			**122.83**	**1.13**	**0.92%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1480
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.26%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	36.24%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**59.50%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		30.38%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.61%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		17.09%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**57.90%**	**59.09%**
Service Charge	1	31.23	31.23	1	35.85	35.85	4.62	14.79%	18.05%	18.42%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0047	6.58	1,400	0.0000	0.00	-6.58	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,400	0.0000	0.04	1,400	0.0000	0.04	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**37.86**			**35.90**	**-1.96**	**-5.18%**	**18.07%**	**18.44%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.40%	0.41%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.62%	3.69%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.30%	3.37%
Sub-Total: Distribution (based on two-tier RPP prices)			**45.83**			**43.87**	**-1.96**	**-4.28%**	**22.08%**	**22.54%**
Sub-Total: Distribution (based on TOU prices)			**45.21**			**43.25**	**-1.96**	**-4.34%**	**21.77%**	**22.21%**
Retail Transmission Rate – Network Service Rate	1,480	0.0078	11.58	1,480	0.0078	11.58	0.00	0.00%	5.83%	5.95%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,480	0.0064	9.53	1,480	0.0064	9.53	0.00	0.00%	4.80%	4.89%
Sub-Total: Retail Transmission			**21.11**			**21.11**	**0.00**	**0.00%**	**10.63%**	**10.84%**
Sub-Total: Delivery (based on two-tier RPP prices)			**66.94**			**64.98**	**-1.96**	**-2.93%**	**32.71%**	**33.38%**
Sub-Total: Delivery (based on TOU prices)			**66.32**			**64.36**	**-1.96**	**-2.96%**	**32.39%**	**33.06%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.68%	2.74%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**3.03%**	**3.09%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**191.16**			**189.20**	**-1.96**	**-1.03%**	**95.24%**	
HST		0.13	24.85		0.13	24.60	-0.25	-1.03%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**216.01**			**213.80**	**-2.21**	**-1.03%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.29		-0.08	-15.14	0.16	1.03%	-7.62%	
Total Amount on Two-Tier RPP			**200.72**			**198.66**	**-2.06**	**-1.03%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**187.36**			**185.40**	**-1.96**	**-1.05%**		**95.24%**
HST		0.13	24.36		0.13	24.10	-0.25	-1.05%		12.38%
Total Electricity Charge on TOU (including HST)			**211.72**			**209.50**	**-2.21**	**-1.05%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.99		-0.08	-14.83	0.16	1.05%		-7.62%
Total Amount on TOU			**196.73**			**194.67**	**-2.06**	**-1.05%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	430
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	37.61%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**37.61%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		20.06%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.67%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		11.28%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**40.13%**	**39.02%**
Service Charge	1	42.19	36.43	1	47.06	36.43	0.00	0.00%	44.48%	43.25%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0193	0.00	400	0.0160	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	400	0.0000	0.01	400	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.44**			**36.44**	**0.00**	**0.00%**	**44.50%**	**43.26%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.96%	0.94%
Line Losses on Cost of Power (based on two-tier RPP prices)	30	0.0770	2.34	30	0.0770	2.34	0.00	0.00%	2.86%	2.78%
Line Losses on Cost of Power (based on TOU prices)	30	0.0822	2.50	30	0.0822	2.50	0.00	0.00%	3.05%	2.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.57**			**39.57**	**0.00**	**0.00%**	**48.32%**	**46.98%**
Sub-Total: Distribution (based on TOU prices)			**39.73**			**39.73**	**0.00**	**0.00%**	**48.51%**	**47.17%**
Retail Transmission Rate – Network Service Rate	430	0.0072	3.10	430	0.0072	3.10	0.00	0.00%	3.79%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	430	0.0060	2.60	430	0.0060	2.60	0.00	0.00%	3.17%	3.08%
Sub-Total: Retail Transmission			**5.70**			**5.70**	**0.00**	**0.00%**	**6.96%**	**6.76%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.27**			**45.27**	**0.00**	**0.00%**	**55.28%**	**53.75%**
Sub-Total: Delivery (based on TOU prices)			**45.43**			**45.43**	**0.00**	**0.00%**	**55.47%**	**53.93%**
Wholesale Market Service Rate	430	0.0036	1.55	430	0.0036	1.55	0.00	0.00%	1.89%	1.84%
Rural Rate Protection Charge	430	0.0003	0.13	430	0.0003	0.13	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	430	0.0000	0.00	430	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%	0.30%
Sub-Total: Regulatory			**1.93**			**1.93**	**0.00**	**0.00%**	**2.35%**	**2.29%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**78.00**			**78.00**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.14		0.13	10.14	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**88.14**			**88.14**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.24		-0.08	-6.24	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**81.90**			**81.90**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**80.22**			**80.22**	**0.00**	**0.00%**		**95.24%**
HST		0.13	10.43		0.13	10.43	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**90.65**			**90.65**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.42		-0.08	-6.42	0.00	0.00%		-7.62%
Total Amount on TOU			**84.23**			**84.23**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Typical Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	807
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.88%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.07%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.95%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.66%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.81%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.43%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.53%**	**49.89%**
Service Charge	1	42.19	36.43	1	47.06	36.43	0.00	0.00%	29.87%	29.50%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0193	0.00	750	0.0160	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**29.89%**	**29.51%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	4.21%	4.15%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	3.84%	3.79%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.37**			**42.37**	**0.00**	**0.00%**	**34.74%**	**34.31%**
Sub-Total: Distribution (based on TOU prices)			**41.92**			**41.92**	**0.00**	**0.00%**	**34.37%**	**33.94%**
Retail Transmission Rate – Network Service Rate	807	0.0072	5.82	807	0.0072	5.82	0.00	0.00%	4.77%	4.71%
Retail Transmission Rate – Line and Transformation Connection Service Rate	807	0.0060	4.87	807	0.0060	4.87	0.00	0.00%	3.99%	3.94%
Sub-Total: Retail Transmission			**10.68**			**10.68**	**0.00**	**0.00%**	**8.76%**	**8.65%**
Sub-Total: Delivery (based on two-tier RPP prices)			**53.05**			**53.05**	**0.00**	**0.00%**	**43.50%**	**42.96%**
Sub-Total: Delivery (based on TOU prices)			**52.61**			**52.61**	**0.00**	**0.00%**	**43.13%**	**42.59%**
Wholesale Market Service Rate	807	0.0036	2.91	807	0.0036	2.91	0.00	0.00%	2.38%	2.35%
Rural Rate Protection Charge	807	0.0003	0.24	807	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	807	0.0000	0.00	807	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.40**			**3.40**	**0.00**	**0.00%**	**2.79%**	**2.75%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**116.15**			**116.15**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.10		0.13	15.10	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**131.25**			**131.25**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.29		-0.08	-9.29	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**121.96**			**121.96**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.62**			**117.62**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.29		0.13	15.29	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**132.91**			**132.91**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.41	0.00	0.00%		-7.62%
Total Amount on TOU			**123.50**			**123.50**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	920
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	990
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	32.41%	
Energy Second Tier (kWh)	320	0.090	28.80	320	0.090	28.80	0.00	0.00%	20.20%	
Sub-Total: Energy (RPP)			**75.00**			**75.00**	**0.00**	**0.00%**	**52.62%**	
TOU-Off Peak	598	0.065	38.87	598	0.065	38.87	0.00	0.00%		27.26%
TOU-Mid Peak	156	0.095	14.86	156	0.095	14.86	0.00	0.00%		10.42%
TOU-On Peak	166	0.132	21.86	166	0.132	21.86	0.00	0.00%		15.33%
Sub-Total: Energy (TOU)			**75.59**			**75.59**	0.00	0.00%	**53.03%**	**53.01%**
Service Charge	1	42.19	36.43	1	47.06	36.43	0.00	0.00%	25.56%	25.55%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	920	0.0193	0.00	920	0.0160	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	920	0.0000	0.02	920	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**25.57%**	**25.57%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.55%	0.55%
Line Losses on Cost of Power (based on two-tier RPP prices)	70	0.0900	6.29	70	0.0900	6.29	0.00	0.00%	4.41%	4.41%
Line Losses on Cost of Power (based on TOU prices)	70	0.0822	5.74	70	0.0822	5.74	0.00	0.00%	4.03%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.54**			**43.54**	**0.00**	**0.00%**	**30.54%**	**30.53%**
Sub-Total: Distribution (based on TOU prices)			**42.99**			**42.99**	**0.00**	**0.00%**	**30.16%**	**30.15%**
Retail Transmission Rate – Network Service Rate	990	0.0072	7.13	990	0.0072	7.13	0.00	0.00%	5.01%	5.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	990	0.0060	5.97	990	0.0060	5.97	0.00	0.00%	4.19%	4.19%
Sub-Total: Retail Transmission			**13.11**			**13.11**	**0.00**	**0.00%**	**9.19%**	**9.19%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.64**			**56.64**	**0.00**	**0.00%**	**39.74%**	**39.73%**
Sub-Total: Delivery (based on TOU prices)			**56.09**			**56.09**	**0.00**	**0.00%**	**39.35%**	**39.34%**
Wholesale Market Service Rate	990	0.0036	3.56	990	0.0036	3.56	0.00	0.00%	2.50%	2.50%
Rural Rate Protection Charge	990	0.0003	0.30	990	0.0003	0.30	0.00	0.00%	0.21%	0.21%
Ontario Electricity Support Program Charge	990	0.0000	0.00	990	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**4.11**			**4.11**	**0.00**	**0.00%**	**2.88%**	**2.88%**
Debt Retirement Charge (DRC)	920	0.000	**0.00**	920	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**135.75**			**135.75**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	17.65		0.13	17.65	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**153.40**			**153.40**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.86	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**142.54**			**142.54**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**135.79**			**135.79**	**0.00**	**0.00%**		**95.24%**
HST		0.13	17.65		0.13	17.65	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**153.44**			**153.44**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.86	0.00	0.00%		-7.62%
Total Amount on TOU			**142.58**			**142.58**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1937
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.55%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.36%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.91%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.51%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		12.05%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.72%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**59.37%**	**61.28%**
Service Charge	1	42.19	36.43	1	47.06	36.43	0.00	0.00%	14.63%	15.10%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0193	0.00	1,800	0.0160	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,800	0.0000	0.04	1,800	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.47**			**36.47**	**0.00**	**0.00%**	**14.64%**	**15.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.32%	0.33%
Line Losses on Cost of Power (based on two-tier RPP prices)	137	0.0900	12.31	137	0.0900	12.31	0.00	0.00%	4.94%	5.10%
Line Losses on Cost of Power (based on TOU prices)	137	0.0822	11.24	137	0.0822	11.24	0.00	0.00%	4.51%	4.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.57**			**49.57**	**0.00**	**0.00%**	**19.90%**	**20.54%**
Sub-Total: Distribution (based on TOU prices)			**48.50**			**48.50**	**0.00**	**0.00%**	**19.47%**	**20.10%**
Retail Transmission Rate – Network Service Rate	1,937	0.0072	13.96	1,937	0.0072	13.96	0.00	0.00%	5.60%	5.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,937	0.0060	11.68	1,937	0.0060	11.68	0.00	0.00%	4.69%	4.84%
Sub-Total: Retail Transmission			**25.64**			**25.64**	**0.00**	**0.00%**	**10.29%**	**10.63%**
Sub-Total: Delivery (based on two-tier RPP prices)			**75.21**			**75.21**	**0.00**	**0.00%**	**30.20%**	**31.17%**
Sub-Total: Delivery (based on TOU prices)			**74.14**			**74.14**	**0.00**	**0.00%**	**29.77%**	**30.72%**
Wholesale Market Service Rate	1,937	0.0036	6.97	1,937	0.0036	6.97	0.00	0.00%	2.80%	2.89%
Rural Rate Protection Charge	1,937	0.0003	0.58	1,937	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,937	0.0000	0.00	1,937	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.80**			**7.80**	**0.00**	**0.00%**	**3.13%**	**3.23%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**237.22**			**237.22**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	30.84		0.13	30.84	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**268.06**			**268.06**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.98		-0.08	-18.98	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**249.08**			**249.08**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**229.83**			**229.83**	**0.00**	**0.00%**		**95.24%**
HST		0.13	29.88		0.13	29.88	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**259.71**			**259.71**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.39		-0.08	-18.39	0.00	0.00%		-7.62%
Total Amount on TOU			**241.32**			**241.32**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	450
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	497
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	450	0.077	34.65	450	0.077	34.65	0.00	0.00%	39.36%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**34.65**			**34.65**	**0.00**	**0.00%**	**39.36%**	
TOU-Off Peak	293	0.065	19.01	293	0.065	19.01	0.00	0.00%		20.96%
TOU-Mid Peak	77	0.095	7.27	77	0.095	7.27	0.00	0.00%		8.01%
TOU-On Peak	81	0.132	10.69	81	0.132	10.69	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**36.97**			**36.97**	0.00	0.00%	**42.00%**	**40.75%**
Service Charge (RRRP credit applied)	1	34.09	34.09	1	44.12	36.43	2.34	6.87%	41.39%	40.16%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	450	0.0321	2.34	450	0.0269	0.00	-2.34	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	450	0.0000	0.00	450	0.0000	0.00	0.00	0.00%	0.01%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.41**			**36.41**	**0.00**	**0.00%**	**41.37%**	**40.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.90%	0.87%
Line Losses on Cost of Power (based on two-tier RPP prices)	47	0.0770	3.64	47	0.0770	3.64	0.00	0.00%	4.13%	4.01%
Line Losses on Cost of Power (based on TOU prices)	47	0.0822	3.88	47	0.0822	3.88	0.00	0.00%	4.41%	4.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.84**			**40.84**	**0.00**	**0.00%**	**46.40%**	**45.02%**
Sub-Total: Distribution (based on TOU prices)			**41.09**			**41.09**	**0.00**	**0.00%**	**46.68%**	**45.29%**
Retail Transmission Rate – Network Service Rate	497	0.0067	3.35	497	0.0067	3.35	0.00	0.00%	3.81%	3.69%
Retail Transmission Rate – Line and Transformation Connection Service Rate	497	0.0056	2.80	497	0.0056	2.80	0.00	0.00%	3.18%	3.09%
Sub-Total: Retail Transmission			**6.15**			**6.15**	**0.00**	**0.00%**	**6.99%**	**6.78%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.99**			**46.99**	**0.00**	**0.00%**	**53.39%**	**51.80%**
Sub-Total: Delivery (based on TOU prices)			**47.24**			**47.24**	**0.00**	**0.00%**	**53.66%**	**52.07%**
Wholesale Market Service Rate	497	0.0036	1.79	497	0.0036	1.79	0.00	0.00%	2.03%	1.97%
Rural Rate Protection Charge	497	0.0003	0.15	497	0.0003	0.15	0.00	0.00%	0.17%	0.16%
Ontario Electricity Support Program Charge	497	0.0000	0.00	497	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%	0.28%
Sub-Total: Regulatory			**2.19**			**2.19**	**0.00**	**0.00%**	**2.49%**	**2.41%**
Debt Retirement Charge (DRC)	450	0.000	**0.00**	450	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**83.83**			**83.83**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.90		0.13	10.90	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**94.73**			**94.73**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.71		-0.08	-6.71	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**88.02**			**88.02**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**86.40**			**86.40**	**0.00**	**0.00%**		**95.24%**
HST		0.13	11.23		0.13	11.23	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**97.63**			**97.63**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.91		-0.08	-6.91	0.00	0.00%		-7.62%
Total Amount on TOU			**90.72**			**90.72**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Typical Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	829
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.37%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.92%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.30%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.35%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.69%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.26%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.85%**	**49.30%**
Service Charge (RRRP credit applied)	1	34.09	34.09	1	44.12	36.43	2.34	6.87%	29.47%	29.15%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	750	0.0321	2.34	750	0.0269	0.00	-2.34	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.01	750	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**29.46%**	**29.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.63%
Line Losses on Cost of Power (based on two-tier RPP prices)	79	0.0900	7.09	79	0.0900	7.09	0.00	0.00%	5.73%	5.67%
Line Losses on Cost of Power (based on TOU prices)	79	0.0822	6.47	79	0.0822	6.47	0.00	0.00%	5.23%	5.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.29**			**44.29**	**0.00**	**0.00%**	**35.83%**	**35.44%**
Sub-Total: Distribution (based on TOU prices)			**43.68**			**43.68**	**0.00**	**0.00%**	**35.33%**	**34.95%**
Retail Transmission Rate – Network Service Rate	829	0.0067	5.59	829	0.0067	5.59	0.00	0.00%	4.52%	4.47%
Retail Transmission Rate – Line and Transformation Connection Service Rate	829	0.0056	4.67	829	0.0056	4.67	0.00	0.00%	3.77%	3.73%
Sub-Total: Retail Transmission			**10.25**			**10.25**	**0.00**	**0.00%**	**8.29%**	**8.20%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.55**			**54.55**	**0.00**	**0.00%**	**44.13%**	**43.64%**
Sub-Total: Delivery (based on TOU prices)			**53.93**			**53.93**	**0.00**	**0.00%**	**43.63%**	**43.15%**
Wholesale Market Service Rate	829	0.0036	2.98	829	0.0036	2.98	0.00	0.00%	2.41%	2.39%
Rural Rate Protection Charge	829	0.0003	0.25	829	0.0003	0.25	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	829	0.0000	0.00	829	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.48**			**3.48**	**0.00**	**0.00%**	**2.82%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**117.73**			**117.73**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.30		0.13	15.30	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**133.03**			**133.03**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.42		-0.08	-9.42	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**123.61**			**123.61**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**119.03**			**119.03**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.47		0.13	15.47	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**134.50**			**134.50**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.52		-0.08	-9.52	0.00	0.00%		-7.62%
Total Amount on TOU			**124.98**			**124.98**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	1152
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1273
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	26.68%	
Energy Second Tier (kWh)	552	0.090	49.68	552	0.090	49.68	0.00	0.00%	28.69%	
Sub-Total: Energy (RPP)			**95.88**			**95.88**	**0.00**	**0.00%**	**55.36%**	
TOU-Off Peak	749	0.065	48.67	749	0.065	48.67	0.00	0.00%		28.48%
TOU-Mid Peak	196	0.095	18.60	196	0.095	18.60	0.00	0.00%		10.89%
TOU-On Peak	207	0.132	27.37	207	0.132	27.37	0.00	0.00%		16.02%
Sub-Total: Energy (TOU)			**94.65**			**94.65**	0.00	0.00%	**54.65%**	**55.38%**
Service Charge (RRRP credit applied)	1	34.09	34.09	1	44.12	36.43	2.34	6.87%	21.04%	21.32%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	1,152	0.0321	2.34	1,152	0.0269	0.00	-2.34	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,152	0.0000	0.01	1,152	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**21.03%**	**21.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	121	0.0900	10.89	121	0.0900	10.89	0.00	0.00%	6.29%	6.37%
Line Losses on Cost of Power (based on TOU prices)	121	0.0822	9.94	121	0.0822	9.94	0.00	0.00%	5.74%	5.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**48.10**			**48.10**	**0.00**	**0.00%**	**27.77%**	**28.14%**
Sub-Total: Distribution (based on TOU prices)			**47.15**			**47.15**	**0.00**	**0.00%**	**27.22%**	**27.59%**
Retail Transmission Rate – Network Service Rate	1,273	0.0067	8.58	1,273	0.0067	8.58	0.00	0.00%	4.95%	5.02%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,273	0.0056	7.17	1,273	0.0056	7.17	0.00	0.00%	4.14%	4.19%
Sub-Total: Retail Transmission			**15.75**			**15.75**	**0.00**	**0.00%**	**9.09%**	**9.21%**
Sub-Total: Delivery (based on two-tier RPP prices)			**63.84**			**63.84**	**0.00**	**0.00%**	**36.86%**	**37.36%**
Sub-Total: Delivery (based on TOU prices)			**62.90**			**62.90**	**0.00**	**0.00%**	**36.32%**	**36.80%**
Wholesale Market Service Rate	1,273	0.0036	4.58	1,273	0.0036	4.58	0.00	0.00%	2.65%	2.68%
Rural Rate Protection Charge	1,273	0.0003	0.38	1,273	0.0003	0.38	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,273	0.0000	0.00	1,273	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.15%
Sub-Total: Regulatory			**5.21**			**5.21**	**0.00**	**0.00%**	**3.01%**	**3.05%**
Debt Retirement Charge (DRC)	1,152	0.000	**0.00**	1,152	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**164.94**			**164.94**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	21.44		0.13	21.44	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**186.38**			**186.38**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.20		-0.08	-13.20	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**173.18**			**173.18**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**162.76**			**162.76**	**0.00**	**0.00%**		**95.24%**
HST		0.13	21.16		0.13	21.16	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**183.92**			**183.92**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.02		-0.08	-13.02	0.00	0.00%		-7.62%
Total Amount on TOU			**170.90**			**170.90**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	2300
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	2542
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	14.68%	
Energy Second Tier (kWh)	1,700	0.090	153.00	1,700	0.090	153.00	0.00	0.00%	48.61%	
Sub-Total: Energy (RPP)			**199.20**			**199.20**	**0.00**	**0.00%**	**63.29%**	
TOU-Off Peak	1,495	0.065	97.18	1,495	0.065	97.18	0.00	0.00%		32.18%
TOU-Mid Peak	391	0.095	37.15	391	0.095	37.15	0.00	0.00%		12.30%
TOU-On Peak	414	0.132	54.65	414	0.132	54.65	0.00	0.00%		18.09%
Sub-Total: Energy (TOU)			**188.97**			**188.97**	0.00	0.00%	**60.04%**	**62.57%**
Service Charge (RRRP credit applied)	1	34.09	34.09	1	44.12	36.43	2.34	6.87%	11.57%	12.06%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	2,300	0.0321	2.34	2,300	0.0269	0.00	-2.34	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,300	0.0000	0.02	2,300	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.43**			**36.43**	**0.00**	**0.00%**	**11.58%**	**12.06%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.26%
Line Losses on Cost of Power (based on two-tier RPP prices)	242	0.0900	21.74	242	0.0900	21.74	0.00	0.00%	6.91%	7.20%
Line Losses on Cost of Power (based on TOU prices)	242	0.0822	19.84	242	0.0822	19.84	0.00	0.00%	6.30%	6.57%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.96**			**58.96**	**0.00**	**0.00%**	**18.73%**	**19.52%**
Sub-Total: Distribution (based on TOU prices)			**57.06**			**57.06**	**0.00**	**0.00%**	**18.13%**	**18.89%**
Retail Transmission Rate – Network Service Rate	2,542	0.0067	17.13	2,542	0.0067	17.13	0.00	0.00%	5.44%	5.67%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,542	0.0056	14.31	2,542	0.0056	14.31	0.00	0.00%	4.55%	4.74%
Sub-Total: Retail Transmission			**31.44**			**31.44**	**0.00**	**0.00%**	**9.99%**	**10.41%**
Sub-Total: Delivery (based on two-tier RPP prices)			**90.40**			**90.40**	**0.00**	**0.00%**	**28.72%**	**29.93%**
Sub-Total: Delivery (based on TOU prices)			**88.50**			**88.50**	**0.00**	**0.00%**	**28.12%**	**29.30%**
Wholesale Market Service Rate	2,542	0.0036	9.15	2,542	0.0036	9.15	0.00	0.00%	2.91%	3.03%
Rural Rate Protection Charge	2,542	0.0003	0.76	2,542	0.0003	0.76	0.00	0.00%	0.24%	0.25%
Ontario Electricity Support Program Charge	2,542	0.0000	0.00	2,542	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**10.16**			**10.16**	**0.00**	**0.00%**	**3.23%**	**3.36%**
Debt Retirement Charge (DRC)	2,300	0.000	**0.00**	2,300	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**299.76**			**299.76**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	38.97		0.13	38.97	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**338.73**			**338.73**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.98		-0.08	-23.98	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**314.75**			**314.75**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**287.63**			**287.63**	**0.00**	**0.00%**		**95.24%**
HST		0.13	37.39		0.13	37.39	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**325.02**			**325.02**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.01		-0.08	-23.01	0.00	0.00%		-7.62%
Total Amount on TOU			**302.01**			**302.01**	**0.00**	**0.00%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	50
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	55.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	50	0.077	3.85	50	0.077	3.85	0.00	0.00%	6.29%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**3.85**			**3.85**	**0.00**	**0.00%**	**6.29%**	
TOU-Off Peak	33	0.065	2.11	33	0.065	2.11	0.00	0.00%		3.43%
TOU-Mid Peak	9	0.095	0.81	9	0.095	0.81	0.00	0.00%		1.31%
TOU-On Peak	9	0.132	1.19	9	0.132	1.19	0.00	0.00%		1.93%
Sub-Total: Energy (TOU)			**4.11**			**4.11**	0.00	0.00%	**6.71%**	**6.68%**
Service Charge	1	45.07	45.07	1	50.05	50.05	4.98	11.05%	81.72%	81.33%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	50	0.0528	2.64	50	0.0439	2.20	-0.45	-16.86%	3.58%	3.57%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	50	0.0000	0.00	50	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**47.71**			**52.24**	**4.54**	**9.51%**	**85.30%**	**84.89%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.29%	1.28%
Line Losses on Cost of Power (based on two-tier RPP prices)	5	0.0770	0.40	5	0.0770	0.40	0.00	0.00%	0.65%	0.65%
Line Losses on Cost of Power (based on TOU prices)	5	0.0822	0.43	5	0.0822	0.43	0.00	0.00%	0.70%	0.69%
Sub-Total: Distribution (based on two-tier RPP prices)			**48.90**			**53.43**	**4.54**	**9.27%**	**87.25%**	**86.82%**
Sub-Total: Distribution (based on TOU prices)			**48.93**			**53.46**	**4.54**	**9.27%**	**87.29%**	**86.87%**
Retail Transmission Rate – Network Service Rate	55	0.0057	0.31	55	0.0057	0.31	0.00	0.00%	0.51%	0.51%
Retail Transmission Rate – Line and Transformation Connection Service Rate	55	0.0048	0.27	55	0.0048	0.27	0.00	0.00%	0.43%	0.43%
Sub-Total: Retail Transmission			**0.58**			**0.58**	**0.00**	**0.00%**	**0.94%**	**0.94%**
Sub-Total: Delivery (based on two-tier RPP prices)			**49.48**			**54.01**	**4.54**	**9.17%**	**88.19%**	**87.76%**
Sub-Total: Delivery (based on TOU prices)			**49.50**			**54.04**	**4.54**	**9.16%**	**88.24%**	**87.81%**
Wholesale Market Service Rate	55	0.0036	0.20	55	0.0036	0.20	0.00	0.00%	0.32%	0.32%
Rural Rate Protection Charge	55	0.0003	0.02	55	0.0003	0.02	0.00	0.00%	0.03%	0.03%
Ontario Electricity Support Program Charge	55	0.0000	0.00	55	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.41%	0.41%
Sub-Total: Regulatory			**0.47**			**0.47**	**0.00**	**0.00%**	**0.76%**	**0.76%**
Debt Retirement Charge (DRC)	50	0.000	**0.00**	50	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**53.79**			**58.33**	**4.54**	**8.43%**	**95.24%**	
HST		0.13	6.99		0.13	7.58	0.59	8.43%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**60.79**			**65.91**	**5.12**	**8.43%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.30		-0.08	-4.67	-0.36	-8.43%	-7.62%	
Total Amount on Two-Tier RPP			**56.48**			**61.24**	**4.76**	**8.43%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**54.08**			**58.61**	**4.54**	**8.39%**		**95.24%**
HST		0.13	7.03		0.13	7.62	0.59	8.39%		12.38%
Total Electricity Charge on TOU (including HST)			**61.11**			**66.23**	**5.12**	**8.39%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.33		-0.08	-4.69	-0.36	-8.39%		-7.62%
Total Amount on TOU			**56.78**			**61.54**	**4.76**	**8.39%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	352
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	388.608
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	352	0.077	27.10	352	0.077	27.10	0.00	0.00%	25.29%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**27.10**			**27.10**	**0.00**	**0.00%**	**25.29%**	
TOU-Off Peak	229	0.065	14.87	229	0.065	14.87	0.00	0.00%		13.61%
TOU-Mid Peak	60	0.095	5.68	60	0.095	5.68	0.00	0.00%		5.20%
TOU-On Peak	63	0.132	8.36	63	0.132	8.36	0.00	0.00%		7.65%
Sub-Total: Energy (TOU)			**28.92**			**28.92**	0.00	0.00%	**26.99%**	**26.47%**
Service Charge	1	45.07	45.07	1	50.05	50.05	4.98	11.05%	46.71%	45.81%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	352	0.0528	18.59	352	0.0439	15.45	-3.13	-16.86%	14.42%	14.14%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	352	0.0000	0.00	352	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**63.66**			**65.50**	**1.85**	**2.90%**	**61.13%**	**59.95%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.74%	0.72%
Line Losses on Cost of Power (based on two-tier RPP prices)	37	0.0770	2.82	37	0.0770	2.82	0.00	0.00%	2.63%	2.58%
Line Losses on Cost of Power (based on TOU prices)	37	0.0822	3.01	37	0.0822	3.01	0.00	0.00%	2.81%	2.75%
Sub-Total: Distribution (based on two-tier RPP prices)			**67.27**			**69.11**	**1.85**	**2.75%**	**64.50%**	**63.25%**
Sub-Total: Distribution (based on TOU prices)			**67.45**			**69.30**	**1.85**	**2.74%**	**64.67%**	**63.43%**
Retail Transmission Rate – Network Service Rate	389	0.0057	2.20	389	0.0057	2.20	0.00	0.00%	2.05%	2.01%
Retail Transmission Rate – Line and Transformation Connection Service Rate	389	0.0048	1.87	389	0.0048	1.87	0.00	0.00%	1.75%	1.71%
Sub-Total: Retail Transmission			**4.07**			**4.07**	**0.00**	**0.00%**	**3.80%**	**3.73%**
Sub-Total: Delivery (based on two-tier RPP prices)			**71.34**			**73.18**	**1.85**	**2.59%**	**68.30%**	**66.98%**
Sub-Total: Delivery (based on TOU prices)			**71.53**			**73.37**	**1.85**	**2.58%**	**68.47%**	**67.15%**
Wholesale Market Service Rate	389	0.0036	1.40	389	0.0036	1.40	0.00	0.00%	1.31%	1.28%
Rural Rate Protection Charge	389	0.0003	0.12	389	0.0003	0.12	0.00	0.00%	0.11%	0.11%
Ontario Electricity Support Program Charge	389	0.0000	0.00	389	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.23%	0.23%
Sub-Total: Regulatory			**1.77**			**1.77**	**0.00**	**0.00%**	**1.65%**	**1.62%**
Debt Retirement Charge (DRC)	352	0.000	**0.00**	352	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**100.21**			**102.05**	**1.85**	**1.84%**	**95.24%**	
HST		0.13	13.03		0.13	13.27	0.24	1.84%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**113.23**			**115.32**	**2.09**	**1.84%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.02		-0.08	-8.16	-0.15	-1.84%	-7.62%	
Total Amount on Two-Tier RPP			**105.22**			**107.16**	**1.94**	**1.84%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**102.21**			**104.06**	**1.85**	**1.81%**		**95.24%**
HST		0.13	13.29		0.13	13.53	0.24	1.81%		12.38%
Total Electricity Charge on TOU (including HST)			**115.50**			**117.59**	**2.09**	**1.81%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.18		-0.08	-8.32	-0.15	-1.81%		-7.62%
Total Amount on TOU			**107.32**			**109.26**	**1.94**	**1.81%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1104
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	21.74%	
Energy Second Tier (kWh)	400	0.090	36.00	400	0.090	36.00	0.00	0.00%	16.94%	
Sub-Total: Energy (RPP)			**82.20**			**82.20**	**0.00**	**0.00%**	**38.67%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.96%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.63%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		11.23%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**38.65%**	**38.82%**
Service Charge	1	45.07	45.07	1	50.05	50.05	4.98	11.05%	23.55%	23.65%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0528	52.80	1,000	0.0439	43.90	-8.90	-16.86%	20.65%	20.74%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.01	1,000	0.0000	0.01	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**97.88**			**93.96**	**-3.92**	**-4.00%**	**44.20%**	**44.39%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.37%	0.37%
Line Losses on Cost of Power (based on two-tier RPP prices)	104	0.0900	9.36	104	0.0900	9.36	0.00	0.00%	4.40%	4.42%
Line Losses on Cost of Power (based on TOU prices)	104	0.0822	8.54	104	0.0822	8.54	0.00	0.00%	4.02%	4.04%
Sub-Total: Distribution (based on two-tier RPP prices)			**108.03**			**104.11**	**-3.92**	**-3.63%**	**48.98%**	**49.19%**
Sub-Total: Distribution (based on TOU prices)			**107.21**			**103.29**	**-3.92**	**-3.66%**	**48.60%**	**48.80%**
Retail Transmission Rate – Network Service Rate	1,104	0.0057	6.24	1,104	0.0057	6.24	0.00	0.00%	2.94%	2.95%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,104	0.0048	5.32	1,104	0.0048	5.32	0.00	0.00%	2.50%	2.51%
Sub-Total: Retail Transmission			**11.57**			**11.57**	**0.00**	**0.00%**	**5.44%**	**5.46%**
Sub-Total: Delivery (based on two-tier RPP prices)			**119.59**			**115.67**	**-3.92**	**-3.28%**	**54.42%**	**54.65%**
Sub-Total: Delivery (based on TOU prices)			**118.78**			**114.86**	**-3.92**	**-3.30%**	**54.04%**	**54.27%**
Wholesale Market Service Rate	1,104	0.0036	3.97	1,104	0.0036	3.97	0.00	0.00%	1.87%	1.88%
Rural Rate Protection Charge	1,104	0.0003	0.33	1,104	0.0003	0.33	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	1,104	0.0000	0.00	1,104	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.12%
Sub-Total: Regulatory			**4.56**			**4.56**	**0.00**	**0.00%**	**2.14%**	**2.15%**
Debt Retirement Charge (DRC)	1,000	0.000	**0.00**	1,000	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**206.35**			**202.43**	**-3.92**	**-1.90%**	**95.24%**	
HST		0.13	26.83		0.13	26.32	-0.51	-1.90%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**233.18**			**228.75**	**-4.43**	**-1.90%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.51		-0.08	-16.19	0.31	1.90%	-7.62%	
Total Amount on Two-Tier RPP			**216.67**			**212.55**	**-4.12**	**-1.90%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**205.49**			**201.57**	**-3.92**	**-1.91%**		**95.24%**
HST		0.13	26.71		0.13	26.20	-0.51	-1.91%		12.38%
Total Electricity Charge on TOU (including HST)			**232.21**			**227.78**	**-4.43**	**-1.91%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.44		-0.08	-16.13	0.31	1.91%		-7.62%
Total Amount on TOU			**215.77**			**211.65**	**-4.12**	**-1.91%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1067
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	33.33%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.99%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**46.32%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		24.18%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.24%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.60%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**47.42%**	**47.03%**
Service Charge	1	24.47	24.47	1	25.1	25.10	0.63	2.57%	14.49%	14.37%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.029	29.00	1,000	0.0299	29.90	0.90	3.10%	17.26%	17.11%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.03	1,000	0.0000	0.03	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**53.51**			**55.04**	**1.53**	**2.86%**	**31.77%**	**31.50%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.45%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.03	67	0.0900	6.03	0.00	0.00%	3.48%	3.45%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.50	67	0.0822	5.50	0.00	0.00%	3.18%	3.15%
Sub-Total: Distribution (based on two-tier RPP prices)			**60.33**			**61.86**	**1.53**	**2.54%**	**35.70%**	**35.41%**
Sub-Total: Distribution (based on TOU prices)			**59.80**			**61.33**	**1.53**	**2.56%**	**35.40%**	**35.11%**
Retail Transmission Rate – Network Service Rate	1,067	0.0061	6.52	1,067	0.0061	6.52	0.00	0.00%	3.76%	3.73%
Retail Transmission Rate – Line and Transformation Connection S	1,067	0.0047	4.96	1,067	0.0047	4.96	0.00	0.00%	2.87%	2.84%
Sub-Total: Retail Transmission			**11.48**			**11.48**	**0.00**	**0.00%**	**6.63%**	**6.57%**
Sub-Total: Delivery (based on two-tier RPP prices)			**71.81**			**73.34**	**1.53**	**2.13%**	**42.33%**	**41.98%**
Sub-Total: Delivery (based on TOU prices)			**71.28**			**72.81**	**1.53**	**2.15%**	**42.03%**	**41.68%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.22%	2.20%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.55%**	**2.53%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.04%**	**4.01%**
Total Electricty Charge on Two-Tier RPP			**163.47**			**165.00**	**1.53**	**0.94%**	**95.24%**	
HST		0.13	21.25		0.13	21.45	0.20	0.94%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**184.72**			**186.45**	**1.73**	**0.94%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.08		-0.08	-13.20	-0.12	-0.94%	-7.62%	
Total Amount on Two-Tier RPP			**171.64**			**173.25**	**1.61**	**0.94%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**164.85**			**166.38**	**1.53**	**0.93%**		**95.24%**
HST		0.13	21.43		0.13	21.63	0.20	0.93%		12.38%
Total Electricity Charge on TOU (including HST)			**186.28**			**188.01**	**1.73**	**0.93%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.19		-0.08	-13.31	-0.12	-0.93%		-7.62%
Total Amount on TOU			**173.10**			**174.70**	**1.61**	**0.93%**		**100.00%**

2020 Bill Impacts (Typical Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2134
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.54%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	34.17%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**51.70%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		26.25%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.03%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		14.76%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**49.90%**	**51.04%**
Service Charge	1	24.47	24.47	1	25.1	25.10	0.63	2.57%	7.62%	7.80%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.029	58.00	2,000	0.0299	59.80	1.80	3.10%	18.16%	18.57%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.06	2,000	0.0000	0.06	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**82.54**			**84.97**	**2.43**	**2.94%**	**25.80%**	**26.39%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	134	0.0900	12.06	134	0.0900	12.06	0.00	0.00%	3.66%	3.75%
Line Losses on Cost of Power (based on TOU prices)	134	0.0822	11.01	134	0.0822	11.01	0.00	0.00%	3.34%	3.42%
Sub-Total: Distribution (based on two-tier RPP prices)			**95.39**			**97.82**	**2.43**	**2.55%**	**29.71%**	**30.38%**
Sub-Total: Distribution (based on TOU prices)			**94.34**			**96.77**	**2.43**	**2.58%**	**29.39%**	**30.06%**
Retail Transmission Rate – Network Service Rate	2,134	0.0061	13.03	2,134	0.0061	13.03	0.00	0.00%	3.96%	4.05%
Retail Transmission Rate – Line and Transformation Connection S	2,134	0.0047	9.93	2,134	0.0047	9.93	0.00	0.00%	3.01%	3.08%
Sub-Total: Retail Transmission			**22.96**			**22.96**	**0.00**	**0.00%**	**6.97%**	**7.13%**
Sub-Total: Delivery (based on two-tier RPP prices)			**118.35**			**120.78**	**2.43**	**2.05%**	**36.68%**	**37.51%**
Sub-Total: Delivery (based on TOU prices)			**117.30**			**119.73**	**2.43**	**2.07%**	**36.36%**	**37.19%**
Wholesale Market Service Rate	2,134	0.0036	7.68	2,134	0.0036	7.68	0.00	0.00%	2.33%	2.39%
Rural Rate Protection Charge	2,134	0.0003	0.64	2,134	0.0003	0.64	0.00	0.00%	0.19%	0.20%
Ontario Electricity Support Program Charge	2,134	0.0000	0.00	2,134	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.60%**	**2.66%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.25%**	**4.35%**
Total Electricty Charge on Two-Tier RPP			**311.17**			**313.60**	**2.43**	**0.78%**	**95.24%**	
HST		0.13	40.45		0.13	40.77	0.32	0.78%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**351.62**			**354.37**	**2.75**	**0.78%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.89		-0.08	-25.09	-0.19	-0.78%	-7.62%	
Total Amount on Two-Tier RPP			**326.73**			**329.28**	**2.55**	**0.78%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**304.19**			**306.62**	**2.43**	**0.80%**		**95.24%**
HST		0.13	39.54		0.13	39.86	0.32	0.80%		12.38%
Total Electricity Charge on TOU (including HST)			**343.73**			**346.48**	**2.75**	**0.80%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.34		-0.08	-24.53	-0.19	-0.80%		-7.62%
Total Amount on TOU			**319.40**			**321.95**	**2.55**	**0.80%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2759
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2944
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.90%	
Energy Second Tier (kWh)	2,009	0.090	180.81	2,009	0.090	180.81	0.00	0.00%	40.39%	
Sub-Total: Energy (RPP)			**238.56**			**238.56**	**0.00**	**0.00%**	**53.29%**	
TOU-Off Peak	1,793	0.065	116.57	1,793	0.065	116.57	0.00	0.00%		26.88%
TOU-Mid Peak	469	0.095	44.56	469	0.095	44.56	0.00	0.00%		10.27%
TOU-On Peak	497	0.132	65.55	497	0.132	65.55	0.00	0.00%		15.11%
Sub-Total: Energy (TOU)			**226.68**			**226.68**	0.00	0.00%	**50.63%**	**52.27%**
Service Charge	1	24.47	24.47	1	25.1	25.10	0.63	2.57%	5.61%	5.79%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,759	0.029	80.01	2,759	0.0299	82.49	2.48	3.10%	18.43%	19.02%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,759	0.0000	0.08	2,759	0.0000	0.08	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**104.57**			**107.68**	**3.11**	**2.98%**	**24.05%**	**24.83%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.18%	0.18%
Line Losses on Cost of Power (based on two-tier RPP prices)	185	0.0900	16.64	185	0.0900	16.64	0.00	0.00%	3.72%	3.84%
Line Losses on Cost of Power (based on TOU prices)	185	0.0822	15.19	185	0.0822	15.19	0.00	0.00%	3.39%	3.50%
Sub-Total: Distribution (based on two-tier RPP prices)			**122.00**			**125.11**	**3.11**	**2.55%**	**27.95%**	**28.85%**
Sub-Total: Distribution (based on TOU prices)			**120.55**			**123.66**	**3.11**	**2.58%**	**27.62%**	**28.51%**
Retail Transmission Rate – Network Service Rate	2,944	0.0061	17.98	2,944	0.0061	17.98	0.00	0.00%	4.01%	4.14%
Retail Transmission Rate – Line and Transformation Connection S	2,944	0.0047	13.69	2,944	0.0047	13.69	0.00	0.00%	3.06%	3.16%
Sub-Total: Retail Transmission			**31.67**			**31.67**	**0.00**	**0.00%**	**7.07%**	**7.30%**
Sub-Total: Delivery (based on two-tier RPP prices)			**153.67**			**156.78**	**3.11**	**2.03%**	**35.02%**	**36.15%**
Sub-Total: Delivery (based on TOU prices)			**152.22**			**155.33**	**3.11**	**2.05%**	**34.70%**	**35.81%**
Wholesale Market Service Rate	2,944	0.0036	10.60	2,944	0.0036	10.60	0.00	0.00%	2.37%	2.44%
Rural Rate Protection Charge	2,944	0.0003	0.88	2,944	0.0003	0.88	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,944	0.0000	0.00	2,944	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.73**			**11.73**	**0.00**	**0.00%**	**2.62%**	**2.70%**
Debt Retirement Charge (DRC)	2,759	0.007	**19.31**	2,759	0.007	**19.31**	**0.00**	**0.00%**	**4.31%**	**4.45%**
Total Electricty Charge on Two-Tier RPP			**423.27**			**426.39**	**3.11**	**0.74%**	**95.24%**	
HST		0.13	55.03		0.13	55.43	0.40	0.74%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**478.30**			**481.82**	**3.52**	**0.74%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.86		-0.08	-34.11	-0.25	-0.74%	-7.62%	
Total Amount on Two-Tier RPP			**444.44**			**447.70**	**3.27**	**0.74%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**409.94**			**413.06**	**3.11**	**0.76%**		**95.24%**
HST		0.13	53.29		0.13	53.70	0.40	0.76%		12.38%
Total Electricity Charge on TOU (including HST)			**463.24**			**466.75**	**3.52**	**0.76%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-32.80		-0.08	-33.04	-0.25	-0.76%		-7.62%
Total Amount on TOU			**430.44**			**433.71**	**3.27**	**0.76%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16005
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.45%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	54.40%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**56.85%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		28.34%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		10.83%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		15.94%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**52.27%**	**55.11%**
Service Charge	1	24.47	24.47	1	25.1	25.10	0.63	2.57%	1.06%	1.12%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.029	435.00	15,000	0.0299	448.50	13.50	3.10%	19.02%	20.06%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.45	15,000	0.0000	0.45	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**459.93**			**474.06**	**14.13**	**3.07%**	**20.11%**	**21.20%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,005	0.0900	90.45	1,005	0.0900	90.45	0.00	0.00%	3.84%	4.04%
Line Losses on Cost of Power (based on TOU prices)	1,005	0.0822	82.57	1,005	0.0822	82.57	0.00	0.00%	3.50%	3.69%
Sub-Total: Distribution (based on two-tier RPP prices)			**551.17**			**565.30**	**14.13**	**2.56%**	**23.98%**	**25.28%**
Sub-Total: Distribution (based on TOU prices)			**543.29**			**557.42**	**14.13**	**2.60%**	**23.64%**	**24.93%**
Retail Transmission Rate – Network Service Rate	16,005	0.0061	97.73	16,005	0.0061	97.73	0.00	0.00%	4.15%	4.37%
Retail Transmission Rate – Line and Transformation Connection S	16,005	0.0047	74.46	16,005	0.0047	74.46	0.00	0.00%	3.16%	3.33%
Sub-Total: Retail Transmission			**172.18**			**172.18**	**0.00**	**0.00%**	**7.30%**	**7.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**723.35**			**737.48**	**14.13**	**1.95%**	**31.28%**	**32.98%**
Sub-Total: Delivery (based on TOU prices)			**715.47**			**729.60**	**14.13**	**1.97%**	**30.95%**	**32.63%**
Wholesale Market Service Rate	16,005	0.0036	57.62	16,005	0.0036	57.62	0.00	0.00%	2.44%	2.58%
Rural Rate Protection Charge	16,005	0.0003	4.80	16,005	0.0003	4.80	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	16,005	0.0000	0.00	16,005	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.67**			**62.67**	**0.00**	**0.00%**	**2.66%**	**2.80%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.45%**	**4.70%**
Total Electricty Charge on Two-Tier RPP			**2,231.27**			**2,245.40**	**14.13**	**0.63%**	**95.24%**	
HST		0.13	290.07		0.13	291.90	1.84	0.63%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,521.33**			**2,537.30**	**15.97**	**0.63%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-178.50		-0.08	-179.63	-1.13	-0.63%	-7.62%	
Total Amount on Two-Tier RPP			**2,342.83**			**2,357.67**	**14.84**	**0.63%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,115.54**			**2,129.67**	**14.13**	**0.67%**		**95.24%**
HST		0.13	275.02		0.13	276.86	1.84	0.67%		12.38%
Total Electricity Charge on TOU (including HST)			**2,390.56**			**2,406.53**	**15.97**	**0.67%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-169.24		-0.08	-170.37	-1.13	-0.67%		-7.62%
Total Amount on TOU			**2,221.32**			**2,236.15**	**14.84**	**0.67%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1096
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	26.63%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	10.37%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**37.00%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.37%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.41%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		10.89%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**37.88%**	**37.67%**
Service Charge	1	30.20	30.20	1	30.88	30.88	0.68	2.25%	14.24%	14.16%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0613	61.30	1,000	0.0633	63.30	2.00	3.26%	29.19%	29.02%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.02	1,000	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**91.52**			**94.20**	**2.68**	**2.93%**	**43.44%**	**43.19%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.36%	0.36%
Line Losses on Cost of Power (based on two-tier RPP prices)	96	0.0900	8.64	96	0.0900	8.64	0.00	0.00%	3.98%	3.96%
Line Losses on Cost of Power (based on TOU prices)	96	0.0822	7.89	96	0.0822	7.89	0.00	0.00%	3.64%	3.62%
Sub-Total: Distribution (based on two-tier RPP prices)			**100.95**			**103.63**	**2.68**	**2.65%**	**47.78%**	**47.52%**
Sub-Total: Distribution (based on TOU prices)			**100.20**			**102.88**	**2.68**	**2.67%**	**47.44%**	**47.17%**
Retail Transmission Rate – Network Service Rate	1,096	0.0057	6.24	1,096	0.0057	6.24	0.00	0.00%	2.88%	2.86%
Retail Transmission Rate – Line and Transformation Connection S	1,096	0.0045	4.90	1,096	0.0045	4.90	0.00	0.00%	2.26%	2.25%
Sub-Total: Retail Transmission			**11.14**			**11.14**	**0.00**	**0.00%**	**5.14%**	**5.11%**
Sub-Total: Delivery (based on two-tier RPP prices)			**112.10**			**114.78**	**2.68**	**2.39%**	**52.92%**	**52.63%**
Sub-Total: Delivery (based on TOU prices)			**111.34**			**114.02**	**2.68**	**2.41%**	**52.57%**	**52.28%**
Wholesale Market Service Rate	1,096	0.0036	3.95	1,096	0.0036	3.95	0.00	0.00%	1.82%	1.81%
Rural Rate Protection Charge	1,096	0.0003	0.33	1,096	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,096	0.0000	0.00	1,096	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.11%
Sub-Total: Regulatory			**4.52**			**4.52**	**0.00**	**0.00%**	**2.09%**	**2.07%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.23%**	**3.21%**
Total Electricty Charge on Two-Tier RPP			**203.87**			**206.55**	**2.68**	**1.31%**	**95.24%**	
HST		0.13	26.50		0.13	26.85	0.35	1.31%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**230.37**			**233.40**	**3.03**	**1.31%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.31		-0.08	-16.52	-0.21	-1.31%	-7.62%	
Total Amount on Two-Tier RPP			**214.06**			**216.88**	**2.81**	**1.31%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**205.03**			**207.71**	**2.68**	**1.31%**		**95.24%**
HST		0.13	26.65		0.13	27.00	0.35	1.31%		12.38%
Total Electricity Charge on TOU (including HST)			**231.68**			**234.71**	**3.03**	**1.31%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.40		-0.08	-16.62	-0.21	-1.31%		-7.62%
Total Amount on TOU			**215.28**			**218.09**	**2.81**	**1.31%**		**100.00%**

2020 Bill Impacts (Typical Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2192
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.07%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	27.41%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**41.48%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		20.99%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		8.02%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		11.80%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**40.03%**	**40.81%**
Service Charge	1	30.20	30.20	1	30.88	30.88	0.68	2.25%	7.52%	7.67%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0613	122.60	2,000	0.0633	126.60	4.00	3.26%	30.84%	31.44%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.04	2,000	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**152.84**			**157.52**	**4.68**	**3.06%**	**38.38%**	**39.12%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	192	0.0900	17.28	192	0.0900	17.28	0.00	0.00%	4.21%	4.29%
Line Losses on Cost of Power (based on TOU prices)	192	0.0822	15.77	192	0.0822	15.77	0.00	0.00%	3.84%	3.92%
Sub-Total: Distribution (based on two-tier RPP prices)			**170.91**			**175.59**	**4.68**	**2.74%**	**42.78%**	**43.61%**
Sub-Total: Distribution (based on TOU prices)			**169.41**			**174.09**	**4.68**	**2.76%**	**42.41%**	**43.23%**
Retail Transmission Rate – Network Service Rate	2,192	0.0057	12.48	2,192	0.0057	12.48	0.00	0.00%	3.04%	3.10%
Retail Transmission Rate – Line and Transformation Connection S	2,192	0.0045	9.81	2,192	0.0045	9.81	0.00	0.00%	2.39%	2.44%
Sub-Total: Retail Transmission			**22.29**			**22.29**	**0.00**	**0.00%**	**5.43%**	**5.53%**
Sub-Total: Delivery (based on two-tier RPP prices)			**193.20**			**197.88**	**4.68**	**2.42%**	**48.21%**	**49.14%**
Sub-Total: Delivery (based on TOU prices)			**191.69**			**196.37**	**4.68**	**2.44%**	**47.84%**	**48.77%**
Wholesale Market Service Rate	2,192	0.0036	7.89	2,192	0.0036	7.89	0.00	0.00%	1.92%	1.96%
Rural Rate Protection Charge	2,192	0.0003	0.66	2,192	0.0003	0.66	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,192	0.0000	0.00	2,192	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.80**			**8.80**	**0.00**	**0.00%**	**2.14%**	**2.19%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.41%**	**3.48%**
Total Electricty Charge on Two-Tier RPP			**386.25**			**390.93**	**4.68**	**1.21%**	**95.24%**	
HST		0.13	50.21		0.13	50.82	0.61	1.21%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**436.46**			**441.75**	**5.29**	**1.21%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.90		-0.08	-31.27	-0.37	-1.21%	-7.62%	
Total Amount on Two-Tier RPP			**405.56**			**410.47**	**4.91**	**1.21%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**378.81**			**383.49**	**4.68**	**1.24%**		**95.24%**
HST		0.13	49.25		0.13	49.85	0.61	1.24%		12.38%
Total Electricity Charge on TOU (including HST)			**428.06**			**433.35**	**5.29**	**1.24%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.30		-0.08	-30.68	-0.37	-1.24%		-7.62%
Total Amount on TOU			**397.75**			**402.67**	**4.91**	**1.24%**		**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1982
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2172
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.19%	
Energy Second Tier (kWh)	1,232	0.090	110.88	1,232	0.090	110.88	0.00	0.00%	27.24%	
Sub-Total: Energy (RPP)			**168.63**			**168.63**	**0.00**	**0.00%**	**41.43%**	
TOU-Off Peak	1,288	0.065	83.74	1,288	0.065	83.74	0.00	0.00%		20.97%
TOU-Mid Peak	337	0.095	32.01	337	0.095	32.01	0.00	0.00%		8.02%
TOU-On Peak	357	0.132	47.09	357	0.132	47.09	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**162.84**			**162.84**	0.00	0.00%	**40.01%**	**40.78%**
Service Charge	1	30.20	30.20	1	30.88	30.88	0.68	2.25%	7.59%	7.73%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,982	0.0613	121.50	1,982	0.0633	125.46	3.96	3.26%	30.83%	31.42%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,982	0.0000	0.04	1,982	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**151.74**			**156.38**	**4.64**	**3.06%**	**38.42%**	**39.16%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	190	0.0900	17.12	190	0.0900	17.12	0.00	0.00%	4.21%	4.29%
Line Losses on Cost of Power (based on TOU prices)	190	0.0822	15.63	190	0.0822	15.63	0.00	0.00%	3.84%	3.91%
Sub-Total: Distribution (based on two-tier RPP prices)			**169.65**			**174.30**	**4.64**	**2.74%**	**42.83%**	**43.65%**
Sub-Total: Distribution (based on TOU prices)			**168.16**			**172.80**	**4.64**	**2.76%**	**42.46%**	**43.27%**
Retail Transmission Rate – Network Service Rate	2,172	0.0057	12.37	2,172	0.0057	12.37	0.00	0.00%	3.04%	3.10%
Retail Transmission Rate – Line and Transformation Connection S	2,172	0.0045	9.72	2,172	0.0045	9.72	0.00	0.00%	2.39%	2.43%
Sub-Total: Retail Transmission			**22.09**			**22.09**	**0.00**	**0.00%**	**5.43%**	**5.53%**
Sub-Total: Delivery (based on two-tier RPP prices)			**191.74**			**196.38**	**4.64**	**2.42%**	**48.25%**	**49.18%**
Sub-Total: Delivery (based on TOU prices)			**190.25**			**194.89**	**4.64**	**2.44%**	**47.89%**	**48.80%**
Wholesale Market Service Rate	2,172	0.0036	7.82	2,172	0.0036	7.82	0.00	0.00%	1.92%	1.96%
Rural Rate Protection Charge	2,172	0.0003	0.65	2,172	0.0003	0.65	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,172	0.0000	0.00	2,172	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.72**			**8.72**	**0.00**	**0.00%**	**2.14%**	**2.18%**
Debt Retirement Charge (DRC)	1,982	0.007	**13.87**	1,982	0.007	**13.87**	**0.00**	**0.00%**	**3.41%**	**3.47%**
Total Electricty Charge on Two-Tier RPP			**382.96**			**387.61**	**4.64**	**1.21%**	**95.24%**	
HST		0.13	49.79		0.13	50.39	0.60	1.21%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**432.75**			**438.00**	**5.25**	**1.21%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.64		-0.08	-31.01	-0.37	-1.21%	-7.62%	
Total Amount on Two-Tier RPP			**402.11**			**406.99**	**4.88**	**1.21%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**375.68**			**380.33**	**4.64**	**1.24%**		**95.24%**
HST		0.13	48.84		0.13	49.44	0.60	1.24%		12.38%
Total Electricity Charge on TOU (including HST)			**424.52**			**429.77**	**5.25**	**1.24%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.05		-0.08	-30.43	-0.37	-1.24%		-7.62%
Total Amount on TOU			**394.47**			**399.34**	**4.88**	**1.24%**		**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16440
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	1.97%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	43.81%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**45.79%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		22.62%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		8.65%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		12.72%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**42.10%**	**43.98%**
Service Charge	1	30.20	30.20	1	30.88	30.88	0.68	2.25%	1.05%	1.10%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0613	919.50	15,000	0.0633	949.50	30.00	3.26%	32.44%	33.88%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.30	15,000	0.0000	0.30	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**950.00**			**980.68**	**30.68**	**3.23%**	**33.50%**	**35.00%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,440	0.0900	129.60	1,440	0.0900	129.60	0.00	0.00%	4.43%	4.63%
Line Losses on Cost of Power (based on TOU prices)	1,440	0.0822	118.31	1,440	0.0822	118.31	0.00	0.00%	4.04%	4.22%
Sub-Total: Distribution (based on two-tier RPP prices)			**1,080.39**			**1,111.07**	**30.68**	**2.84%**	**37.96%**	**39.65%**
Sub-Total: Distribution (based on TOU prices)			**1,069.10**			**1,099.78**	**30.68**	**2.87%**	**37.57%**	**39.25%**
Retail Transmission Rate – Network Service Rate	16,440	0.0057	93.59	16,440	0.0057	93.59	0.00	0.00%	3.20%	3.34%
Retail Transmission Rate – Line and Transformation Connection S	16,440	0.0045	73.55	16,440	0.0045	73.55	0.00	0.00%	2.51%	2.62%
Sub-Total: Retail Transmission			**167.15**			**167.15**	**0.00**	**0.00%**	**5.71%**	**5.96%**
Sub-Total: Delivery (based on two-tier RPP prices)			**1,247.54**			**1,278.22**	**30.68**	**2.46%**	**43.67%**	**45.62%**
Sub-Total: Delivery (based on TOU prices)			**1,236.25**			**1,266.93**	**30.68**	**2.48%**	**43.28%**	**45.21%**
Wholesale Market Service Rate	16,440	0.0036	59.18	16,440	0.0036	59.18	0.00	0.00%	2.02%	2.11%
Rural Rate Protection Charge	16,440	0.0003	4.93	16,440	0.0003	4.93	0.00	0.00%	0.17%	0.18%
Ontario Electricity Support Program Charge	16,440	0.0000	0.00	16,440	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**64.37**			**64.37**	**0.00**	**0.00%**	**2.20%**	**2.30%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.59%**	**3.75%**
Total Electricty Charge on Two-Tier RPP			**2,757.15**			**2,787.83**	**30.68**	**1.11%**	**95.24%**	
HST		0.13	358.43		0.13	362.42	3.99	1.11%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**3,115.58**			**3,150.25**	**34.67**	**1.11%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-220.57		-0.08	-223.03	-2.45	-1.11%	-7.62%	
Total Amount on Two-Tier RPP			**2,895.01**			**2,927.23**	**32.21**	**1.11%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,638.01**			**2,668.69**	**30.68**	**1.16%**		**95.24%**
HST		0.13	342.94		0.13	346.93	3.99	1.16%		12.38%
Total Electricity Charge on TOU (including HST)			**2,980.96**			**3,015.62**	**34.67**	**1.16%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-211.04		-0.08	-213.50	-2.45	-1.16%		-7.62%
Total Amount on TOU			**2,769.91**			**2,802.13**	**32.21**	**1.16%**		**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.050
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,750	0.077	1,212.75	15,750	0.077	1,212.75	0.00	0.00%	45.89%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,212.75**			**1,212.75**	**0.00**	**0.00%**	**45.89%**
Service Charge	1	102.72	102.72	1	105.02	105.02	2.30	2.24%	3.97%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	9.9799	598.79	60	10.2932	617.59	18.80	3.14%	23.37%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0112	0.67	60	0.0112	0.67	0.00	0.00%	0.03%
Volumetric Global Adjustment Account Rider	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**702.20**			**723.30**	**21.10**	**3.00%**	**27.37%**
Retail Transmission Rate – Network Service Rate	60	2.23104	133.86	60	2.2310	133.86	0.00	0.00%	5.06%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.704675	102.28	60	1.7047	102.28	0.00	0.00%	3.87%
Sub-Total: Retail Transmission			**236.14**			**236.14**	**0.00**	**0.00%**	**8.93%**
Sub-Total: Delivery			**938.35**			**959.44**	**21.10**	**2.25%**	**36.30%**
Wholesale Market Service Rate	15,750	0.0036	56.70	15,750	0.0036	56.70	0.00	0.00%	2.15%
Rural Rate Protection Charge	15,750	0.0003	4.73	15,750	0.0003	4.73	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.68**			**61.68**	**0.00**	**0.00%**	**2.33%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.97%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,317.77**			**2,338.87**	**21.10**	**0.91%**	**88.50%**
HST		0.13	301.31		0.13	304.05	2.74	0.91%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,619.08**			**2,642.92**	**23.84**	**0.91%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,619.08**			**2,642.92**	**23.84**	**0.91%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	50,525
Peak (kW)	135
Loss factor	1.050
Load factor	51%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	53,051
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	53,051	0.077	4,084.95	53,051	0.077	4,084.95	0.00	0.00%	54.17%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,084.95**			**4,084.95**	**0.00**	**0.00%**	**54.17%**
Service Charge	1	102.72	102.72	1	105.02	105.02	2.30	2.24%	1.39%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	135	9.9799	1,347.29	135	10.2932	1,389.58	42.30	3.14%	18.43%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	135	0.0112	1.51	135	0.0112	1.51	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,451.53**			**1,496.13**	**44.60**	**3.07%**	**19.84%**
Retail Transmission Rate – Network Service Rate	135	2.23104	301.19	135	2.2310	301.19	0.00	0.00%	3.99%
Retail Transmission Rate – Line and Transformation Connection Service Rate	135	1.704675	230.13	135	1.7047	230.13	0.00	0.00%	3.05%
Sub-Total: Retail Transmission			**531.32**			**531.32**	**0.00**	**0.00%**	**7.05%**
Sub-Total: Delivery			**1,982.86**			**2,027.45**	**44.60**	**2.25%**	**26.89%**
Wholesale Market Service Rate	53,051	0.0036	190.98	53,051	0.0036	190.98	0.00	0.00%	2.53%
Rural Rate Protection Charge	53,051	0.0003	15.92	53,051	0.0003	15.92	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**207.15**			**207.15**	**0.00**	**0.00%**	**2.75%**
Debt Retirement Charge (DRC)	50,525	0.007	**353.68**	50,525	0.007	**353.68**	**0.00**	**0.00%**	**4.69%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,628.63**			**6,673.22**	**44.60**	**0.67%**	**88.50%**
HST		0.13	861.72		0.13	867.52	5.80	0.67%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,490.35**			**7,540.74**	**50.39**	**0.67%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,490.35**			**7,540.74**	**50.39**	**0.67%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.050
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	183,750	0.077	14,148.75	183,750	0.077	14,148.75	0.00	0.00%	53.70%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,148.75**			**14,148.75**	**0.00**	**0.00%**	**53.70%**
Service Charge	1	102.72	102.72	1	105.02	105.02	2.30	2.24%	0.40%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	9.9799	4,989.95	500	10.2932	5,146.60	156.65	3.14%	19.53%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0112	5.59	500	0.0112	5.59	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**5,098.28**			**5,257.23**	**158.95**	**3.12%**	**19.95%**
Retail Transmission Rate – Network Service Rate	500	2.23104	1,115.52	500	2.2310	1,115.52	0.00	0.00%	4.23%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.704675	852.34	500	1.7047	852.34	0.00	0.00%	3.24%
Sub-Total: Retail Transmission			**1,967.86**			**1,967.86**	**0.00**	**0.00%**	**7.47%**
Sub-Total: Delivery			**7,066.14**			**7,225.09**	**158.95**	**2.25%**	**27.42%**
Wholesale Market Service Rate	183,750	0.0036	661.50	183,750	0.0036	661.50	0.00	0.00%	2.51%
Rural Rate Protection Charge	183,750	0.0003	55.13	183,750	0.0003	55.13	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**716.88**			**716.88**	**0.00**	**0.00%**	**2.72%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.65%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,156.76**			**23,315.71**	**158.95**	**0.69%**	**88.50%**
HST		0.13	3,010.38		0.13	3,031.04	20.66	0.69%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,167.14**			**26,346.75**	**179.61**	**0.69%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,167.14**			**26,346.75**	**179.61**	**0.69%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.061
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,915
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,915	0.077	1,225.46	15,915	0.077	1,225.46	0.00	0.00%	39.41%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,225.46**			**1,225.46**	**0.00**	**0.00%**	**39.41%**
Service Charge	1	104.19	104.19	1	106.19	106.19	2.00	1.92%	3.41%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	17.3870	1,043.22	60	17.9321	1,075.93	32.71	3.14%	34.60%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0052	0.31	60	0.0052	0.31	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,147.71**			**1,182.42**	**34.71**	**3.02%**	**38.02%**
Retail Transmission Rate – Network Service Rate	60	1.6718	100.31	60	1.6718	100.31	0.00	0.00%	3.23%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.2769	76.61	60	1.2769	76.61	0.00	0.00%	2.46%
Sub-Total: Retail Transmission			**176.92**			**176.92**	**0.00**	**0.00%**	**5.69%**
Sub-Total: Delivery			**1,324.63**			**1,359.34**	**34.71**	**2.62%**	**43.71%**
Wholesale Market Service Rate	15,915	0.0036	57.29	15,915	0.0036	57.29	0.00	0.00%	1.84%
Rural Rate Protection Charge	15,915	0.0003	4.77	15,915	0.0003	4.77	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.32**			**62.32**	**0.00**	**0.00%**	**2.00%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.38%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,717.41**			**2,752.11**	**34.71**	**1.28%**	**88.50%**
HST		0.13	353.26		0.13	357.77	4.51	1.28%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**3,070.67**			**3,109.89**	**39.22**	**1.28%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**3,070.67**			**3,109.89**	**39.22**	**1.28%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	36,104
Peak (kW)	124
Loss factor	1.061
Load factor	40%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	38,306
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	38,306	0.077	2,949.59	38,306	0.077	2,949.59	0.00	0.00%	43.16%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**2,949.59**			**2,949.59**	**0.00**	**0.00%**	**43.16%**
Service Charge	1	104.19	104.19	1	106.19	106.19	2.00	1.92%	1.55%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	124	17.3870	2,155.99	124	17.9321	2,223.58	67.59	3.14%	32.54%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	124	0.0052	0.64	124	0.0052	0.64	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,260.81**			**2,330.40**	**69.59**	**3.08%**	**34.10%**
Retail Transmission Rate – Network Service Rate	124	1.6718	207.31	124	1.6718	207.31	0.00	0.00%	3.03%
Retail Transmission Rate – Line and Transformation Connection Service Rate	124	1.2769	158.34	124	1.2769	158.34	0.00	0.00%	2.32%
Sub-Total: Retail Transmission			**365.64**			**365.64**	**0.00**	**0.00%**	**5.35%**
Sub-Total: Delivery			**2,626.45**			**2,696.04**	**69.59**	**2.65%**	**39.45%**
Wholesale Market Service Rate	38,306	0.0036	137.90	38,306	0.0036	137.90	0.00	0.00%	2.02%
Rural Rate Protection Charge	38,306	0.0003	11.49	38,306	0.0003	11.49	0.00	0.00%	0.17%
Ontario Electricity Support Program Charge	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**149.64**			**149.64**	**0.00**	**0.00%**	**2.19%**
Debt Retirement Charge (DRC)	36,104	0.007	**252.73**	36,104	0.007	**252.73**	**0.00**	**0.00%**	**3.70%**
Total Electricity Charge on Two-Tier RPP (before HST)			**5,978.41**			**6,048.01**	**69.59**	**1.16%**	**88.50%**
HST		0.13	777.19		0.13	786.24	9.05	1.16%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**6,755.61**			**6,834.25**	**78.64**	**1.16%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**6,755.61**			**6,834.25**	**78.64**	**1.16%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.061
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	185,675
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	185,675	0.077	14,296.98	185,675	0.077	14,296.98	0.00	0.00%	47.22%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,296.98**			**14,296.98**	**0.00**	**0.00%**	**47.22%**
Service Charge	1	104.19	104.19	1	106.19	106.19	2.00	1.92%	0.35%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	17.3870	8,693.50	500	17.9321	8,966.05	272.55	3.14%	29.61%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0052	2.58	500	0.0052	2.58	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**8,800.26**			**9,074.81**	**274.55**	**3.12%**	**29.97%**
Retail Transmission Rate – Network Service Rate	500	1.6718	835.91	500	1.6718	835.91	0.00	0.00%	2.76%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.2769	638.46	500	1.2769	638.46	0.00	0.00%	2.11%
Sub-Total: Retail Transmission			**1,474.37**			**1,474.37**	**0.00**	**0.00%**	**4.87%**
Sub-Total: Delivery			**10,274.63**			**10,549.18**	**274.55**	**2.67%**	**34.84%**
Wholesale Market Service Rate	185,675	0.0036	668.43	185,675	0.0036	668.43	0.00	0.00%	2.21%
Rural Rate Protection Charge	185,675	0.0003	55.70	185,675	0.0003	55.70	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**724.38**			**724.38**	**0.00**	**0.00%**	**2.39%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.05%**
Total Electricity Charge on Two-Tier RPP (before HST)			**26,520.98**			**26,795.53**	**274.55**	**1.04%**	**88.50%**
HST		0.13	3,447.73		0.13	3,483.42	35.69	1.04%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**29,968.71**			**30,278.95**	**310.24**	**1.04%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**29,968.71**			**30,278.95**	**310.24**	**1.04%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	300
Peak (kW)	10
Loss factor	1.061
Load factor	4%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	318
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	318	0.077	24.51	318	0.077	24.51	0.00	0.00%	6.33%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**24.51**			**24.51**	**0.00**	**0.00%**	**6.33%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	50.68%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	10	9.8220	98.22	10	10.6446	106.45	8.23	8.38%	27.50%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10	0.0028	0.03	10	0.0028	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**294.42**			**302.65**	**8.23**	**2.79%**	**78.19%**
Retail Transmission Rate – Network Service Rate	10	0.6311	6.31	10	0.6311	6.31	0.00	0.00%	1.63%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	0.5475	5.47	10	0.5475	5.47	0.00	0.00%	1.41%
Sub-Total: Retail Transmission			**11.79**			**11.79**	**0.00**	**0.00%**	**3.04%**
Sub-Total: Delivery			**306.20**			**314.43**	**8.23**	**2.69%**	**81.24%**
Wholesale Market Service Rate	318	0.0036	1.15	318	0.0036	1.15	0.00	0.00%	0.30%
Rural Rate Protection Charge	318	0.0003	0.10	318	0.0003	0.10	0.00	0.00%	0.02%
Ontario Electricity Support Program Charge	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%
Sub-Total: Regulatory			**1.49**			**1.49**	**0.00**	**0.00%**	**0.39%**
Debt Retirement Charge (DRC)	300	0.007	**2.10**	300	0.007	**2.10**	**0.00**	**0.00%**	**0.54%**
Total Electricity Charge on Two-Tier RPP (before HST)			**334.31**			**342.53**	**8.23**	**2.46%**	**88.50%**
HST		0.13	43.46		0.13	44.53	1.07	2.46%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**377.76**			**387.06**	**9.30**	**2.46%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**377.76**			**387.06**	**9.30**	**2.46%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	1,328
Peak (kW)	13
Loss factor	1.061
Load factor	14%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,409
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,409	0.077	108.49	1,409	0.077	108.49	0.00	0.00%	20.28%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**108.49**			**108.49**	**0.00**	**0.00%**	**20.28%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	36.67%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	13	9.8220	127.69	13	10.6446	138.38	10.69	8.38%	25.87%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	13	0.0028	0.04	13	0.0028	0.04	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**323.89**			**334.59**	**10.69**	**3.30%**	**62.54%**
Retail Transmission Rate – Network Service Rate	13	0.6311	8.20	13	0.6311	8.20	0.00	0.00%	1.53%
Retail Transmission Rate – Line and Transformation Connection Service Rate	13	0.5475	7.12	13	0.5475	7.12	0.00	0.00%	1.33%
Sub-Total: Retail Transmission			**15.32**			**15.32**	**0.00**	**0.00%**	**2.86%**
Sub-Total: Delivery			**339.21**			**349.91**	**10.69**	**3.15%**	**65.40%**
Wholesale Market Service Rate	1,409	0.0036	5.07	1,409	0.0036	5.07	0.00	0.00%	0.95%
Rural Rate Protection Charge	1,409	0.0003	0.42	1,409	0.0003	0.42	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**5.75**			**5.75**	**0.00**	**0.00%**	**1.07%**
Debt Retirement Charge (DRC)	1,328	0.007	**9.30**	1,328	0.007	**9.30**	**0.00**	**0.00%**	**1.74%**
Total Electricity Charge on Two-Tier RPP (before HST)			**462.75**			**473.44**	**10.69**	**2.31%**	**88.50%**
HST		0.13	60.16		0.13	61.55	1.39	2.31%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**522.91**			**534.99**	**12.08**	**2.31%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**522.91**			**534.99**	**12.08**	**2.31%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	5,000
Peak (kW)	100
Loss factor	1.061
Load factor	7%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	5,305
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	5,305	0.077	408.49	5,305	0.077	408.49	0.00	0.00%	19.61%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**408.49**			**408.49**	**0.00**	**0.00%**	**19.61%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	9.42%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	9.8220	982.20	100	10.6446	1,064.46	82.26	8.38%	51.11%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0028	0.28	100	0.0028	0.28	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,178.65**			**1,260.91**	**82.26**	**6.98%**	**60.54%**
Retail Transmission Rate – Network Service Rate	100	0.6311	63.11	100	0.6311	63.11	0.00	0.00%	3.03%
Retail Transmission Rate – Line and Transformation Connection Service Rate	100	0.5475	54.75	100	0.5475	54.75	0.00	0.00%	2.63%
Sub-Total: Retail Transmission			**117.86**			**117.86**	**0.00**	**0.00%**	**5.66%**
Sub-Total: Delivery			**1,296.51**			**1,378.77**	**82.26**	**6.34%**	**66.20%**
Wholesale Market Service Rate	5,305	0.0036	19.10	5,305	0.0036	19.10	0.00	0.00%	0.92%
Rural Rate Protection Charge	5,305	0.0003	1.59	5,305	0.0003	1.59	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**20.94**			**20.94**	**0.00**	**0.00%**	**1.01%**
Debt Retirement Charge (DRC)	5,000	0.007	**35.00**	5,000	0.007	**35.00**	**0.00**	**0.00%**	**1.68%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,760.93**			**1,843.19**	**82.26**	**4.67%**	**88.50%**
HST		0.13	228.92		0.13	239.62	10.69	4.67%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**1,989.85**			**2,082.81**	**92.95**	**4.67%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**1,989.85**			**2,082.81**	**92.95**	**4.67%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	200,000
Peak (kW)	500
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	206,800
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	206,800	0.077	15,923.60	206,800	0.077	15,923.60	0.00	0.00%	61.07%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15,923.60**			**15,923.60**	**0.00**	**0.00%**	**61.07%**
Service Charge	1	1223.97	1,223.97	1	1255.93	1,255.93	31.96	2.61%	4.82%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.01%
Distribution Volumetric Rate	500	1.3658	682.92	500	1.4137	706.83	23.90	3.50%	2.71%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	-0.1367	-68.34	500	-0.1367	-68.34	0.00	0.00%	-0.26%
Volumetric Global Adjustment Account Rider	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**1,842.38**			**1,898.24**	**55.86**	**3.03%**	**7.28%**
Retail Transmission Rate – Network Service Rate	500	3.4866	1,743.32	500	3.4866	1,743.32	0.00	0.00%	6.69%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.6022	1,301.08	500	2.6022	1,301.08	0.00	0.00%	4.99%
Sub-Total: Retail Transmission			**3,044.41**			**3,044.41**	**0.00**	**0.00%**	**11.68%**
Sub-Total: Delivery			**4,886.78**			**4,942.65**	**55.86**	**1.14%**	**18.96%**
Wholesale Market Service Rate	206,800	0.0036	744.48	206,800	0.0036	744.48	0.00	0.00%	2.86%
Rural Rate Protection Charge	206,800	0.0003	62.04	206,800	0.0003	62.04	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**806.77**			**806.77**	**0.00**	**0.00%**	**3.09%**
Debt Retirement Charge (DRC)	200,000	0.007	**1,400.00**	200,000	0.007	**1,400.00**	**0.00**	**0.00%**	**5.37%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,017.15**			**23,073.02**	**55.86**	**0.24%**	**88.50%**
HST		0.13	2,992.23		0.13	2,999.49	7.26	0.24%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,009.38**			**26,072.51**	**63.13**	**0.24%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,009.38**			**26,072.51**	**63.13**	**0.24%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	1,601,036
Peak (kW)	3,091
Loss factor	1.034
Load factor	71%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,655,471
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,655,471	0.077	127,471.28	1,655,471	0.077	127,471.28	0.00	0.00%	66.69%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**127,471.28**			**127,471.28**	**0.00**	**0.00%**	**66.69%**
Service Charge	1	1223.97	1,223.97	1	1255.93	1,255.93	31.96	2.61%	0.66%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	3,091	1.3658	4,221.84	3,091	1.4137	4,369.61	147.78	3.50%	2.29%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	3,091	-0.1367	-422.45	3,091	-0.1367	-422.45	0.00	0.00%	-0.22%
Volumetric Global Adjustment Account Rider	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**5,027.18**			**5,206.92**	**179.74**	**3.58%**	**2.72%**
Retail Transmission Rate – Network Service Rate	3,091	3.486648	10,777.23	3,091	3.4866	10,777.23	0.00	0.00%	5.64%
Retail Transmission Rate – Line and Transformation Connection Service Rate	3,091	2.6022	8,043.29	3,091	2.6022	8,043.29	0.00	0.00%	4.21%
Sub-Total: Retail Transmission			**18,820.52**			**18,820.52**	**0.00**	**0.00%**	**9.85%**
Sub-Total: Delivery			**23,847.70**			**24,027.43**	**179.74**	**0.75%**	**12.57%**
Wholesale Market Service Rate	1,655,471	0.0036	5,959.70	1,655,471	0.0036	5,959.70	0.00	0.00%	3.12%
Rural Rate Protection Charge	1,655,471	0.0003	496.64	1,655,471	0.0003	496.64	0.00	0.00%	0.26%
Ontario Electricity Support Program Charge	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**6,456.59**			**6,456.59**	**0.00**	**0.00%**	**3.38%**
Debt Retirement Charge (DRC)	1,601,036	0.007	**11,207.25**	1,601,036	0.007	**11,207.25**	**0.00**	**0.00%**	**5.86%**
Total Electricity Charge on Two-Tier RPP (before HST)			**168,982.82**			**169,162.56**	**179.74**	**0.11%**	**88.50%**
HST		0.13	21,967.77		0.13	21,991.13	23.37	0.11%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**190,950.59**			**191,153.69**	**203.10**	**0.11%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**190,950.59**			**191,153.69**	**203.10**	**0.11%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	4,000,000
Peak (kW)	10,000
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	4,136,000
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	4,136,000	0.077	318,472.00	4,136,000	0.077	318,472.00	0.00	0.00%	64.42%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**318,472.00**			**318,472.00**	**0.00**	**0.00%**	**64.42%**
Service Charge	1	1223.97	1,223.97	1	1255.93	1,255.93	31.96	2.61%	0.25%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	10,000	1.3658	13,658.48	10,000	1.4137	14,136.57	478.08	3.50%	2.86%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10,000	-0.1367	-1,366.70	10,000	-0.1367	-1,366.70	0.00	0.00%	-0.28%
Volumetric Global Adjustment Account Rider	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution			**13,519.57**			**14,029.62**	**510.04**	**3.77%**	**2.84%**
Retail Transmission Rate – Network Service Rate	10,000	3.4866	34,866.48	10,000	3.4866	34,866.48	0.00	0.00%	7.05%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10,000	2.6022	26,021.64	10,000	2.6022	26,021.64	0.00	0.00%	5.26%
Sub-Total: Retail Transmission			**60,888.12**			**60,888.12**	**0.00**	**0.00%**	**12.32%**
Sub-Total: Delivery			**74,407.70**			**74,917.74**	**510.04**	**0.69%**	**15.15%**
Wholesale Market Service Rate	4,136,000	0.0036	14,889.60	4,136,000	0.0036	14,889.60	0.00	0.00%	3.01%
Rural Rate Protection Charge	4,136,000	0.0003	1,240.80	4,136,000	0.0003	1,240.80	0.00	0.00%	0.25%
Ontario Electricity Support Program Charge	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**16,130.65**			**16,130.65**	**0.00**	**0.00%**	**3.26%**
Debt Retirement Charge (DRC)	4,000,000	0.007	**28,000.00**	4,000,000	0.007	**28,000.00**	**0.00**	**0.00%**	**5.66%**
Total Electricity Charge on Two-Tier RPP (before HST)			**437,010.35**			**437,520.39**	**510.04**	**0.12%**	**88.50%**
HST		0.13	56,811.35		0.13	56,877.65	66.31	0.12%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**493,821.69**			**494,398.04**	**576.35**	**0.12%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**493,821.69**			**494,398.04**	**576.35**	**0.12%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	14.56%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**14.56%**
Service Charge	1	35.49	35.49	1	36.66	36.66	1.17	3.30%	69.32%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	0.0291	2.91	100	0.0298	2.98	0.07	2.41%	5.64%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
Volumetric Global Adjustment Account Rider	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution (excluding pass through)			**38.40**			**39.64**	**1.24**	**3.23%**	**74.97%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	1.34%
Sub-Total: Distribution			**39.11**			**40.35**	**1.24**	**3.17%**	**76.31%**
Retail Transmission Rate – Network Service Rate	109	0.0048	0.52	109	0.0048	0.52	0.00	0.00%	0.98%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0038	0.41	109	0.0038	0.41	0.00	0.00%	0.78%
Sub-Total: Retail Transmission			**0.94**			**0.94**	**0.00**	**0.00%**	**1.77%**
Sub-Total: Delivery			**40.05**			**41.29**	**1.24**	**3.10%**	**78.08%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	0.74%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.06%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.47%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**1.28%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**1.32%**
Total Electricity Charge on Two-Tier RPP (before HST)			**49.12**			**50.36**	**1.24**	**2.52%**	**95.24%**
HST		0.13	6.39		0.13	6.55	0.16	2.52%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**55.51**			**56.91**	**1.40**	**2.52%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.93		-0.08	-4.03	-0.10	-2.52%	-7.62%
Total Amount on Two-Tier RPP			**51.58**			**52.88**	**1.30**	**2.52%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	364
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	397
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	364	0.077	28.03	364	0.077	28.03	0.00	0.00%	31.08%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**28.03**			**28.03**	**0.00**	**0.00%**	**31.08%**
Service Charge	1	35.49	35.49	1	36.66	36.66	1.17	3.30%	40.66%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	364	0.0291	10.59	364	0.0298	10.85	0.25	2.41%	12.03%
Volumetric Deferral/Variance Account Rider (including CBR Class	364	0.0000	0.01	364	0.0000	0.01	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution (excluding pass through)			**46.09**			**47.52**	**1.42**	**3.09%**	**52.70%**
Line Losses on Cost of Power	33	0.0770	2.58	33	0.0770	2.58	0.00	0.00%	2.86%
Sub-Total: Distribution			**48.67**			**50.10**	**1.42**	**2.93%**	**55.56%**
Retail Transmission Rate – Network Service Rate	397	0.0048	1.90	397	0.0048	1.90	0.00	0.00%	2.10%
Retail Transmission Rate – Line and Transformation Connection S	397	0.0038	1.51	397	0.0038	1.51	0.00	0.00%	1.67%
Sub-Total: Retail Transmission			**3.40**			**3.40**	**0.00**	**0.00%**	**3.78%**
Sub-Total: Delivery			**52.07**			**53.50**	**1.42**	**2.74%**	**59.33%**
Wholesale Market Service Rate	397	0.0036	1.43	397	0.0036	1.43	0.00	0.00%	1.59%
Rural Rate Protection Charge	397	0.0003	0.12	397	0.0003	0.12	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%
Sub-Total: Regulatory			**1.80**			**1.80**	**0.00**	**0.00%**	**2.00%**
Debt Retirement Charge (DRC)	364	0.007	**2.55**	364	0.007	**2.55**	**0.00**	**0.00%**	**2.83%**
Total Electricity Charge on Two-Tier RPP (before HST)			**84.45**			**85.88**	**1.42**	**1.69%**	**95.24%**
HST		0.13	10.98		0.13	11.16	0.19	1.69%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**95.43**			**97.04**	**1.61**	**1.69%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.76		-0.08	-6.87	-0.11	-1.69%	-7.62%
Total Amount on Two-Tier RPP			**88.67**			**90.17**	**1.50**	**1.69%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1092
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	31.27%
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.18%
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**43.46%**
Service Charge	1	35.49	35.49	1	36.66	36.66	1.17	3.30%	19.85%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0291	29.10	1,000	0.0298	29.80	0.70	2.41%	16.14%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.02	1,000	0.0000	0.02	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution (excluding pass through)			**64.61**			**66.48**	**1.87**	**2.89%**	**36.00%**
Line Losses on Cost of Power	92	0.0900	8.28	92	0.0900	8.28	0.00	0.00%	4.48%
Sub-Total: Distribution			**72.89**			**74.76**	**1.87**	**2.57%**	**40.48%**
Retail Transmission Rate – Network Service Rate	1,092	0.0048	5.21	1,092	0.0048	5.21	0.00	0.00%	2.82%
Retail Transmission Rate – Line and Transformation Connection S	1,092	0.0038	4.14	1,092	0.0038	4.14	0.00	0.00%	2.24%
Sub-Total: Retail Transmission			**9.35**			**9.35**	**0.00**	**0.00%**	**5.06%**
Sub-Total: Delivery			**82.24**			**84.11**	**1.87**	**2.27%**	**45.55%**
Wholesale Market Service Rate	1,092	0.0036	3.93	1,092	0.0036	3.93	0.00	0.00%	2.13%
Rural Rate Protection Charge	1,092	0.0003	0.33	1,092	0.0003	0.33	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%
Sub-Total: Regulatory			**4.51**			**4.51**	**0.00**	**0.00%**	**2.44%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.79%**
Total Electricity Charge on Two-Tier RPP (before HST)			**174.00**			**175.87**	**1.87**	**1.07%**	**95.24%**
HST		0.13	22.62		0.13	22.86	0.24	1.07%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**196.62**			**198.74**	**2.11**	**1.07%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.92		-0.08	-14.07	-0.15	-1.07%	-7.62%
Total Amount on Two-Tier RPP			**182.70**			**184.67**	**1.96**	**1.07%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	20
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	22
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	20	0.077	1.54	20	0.077	1.54	0.00	0.00%	16.98%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1.54**			**1.54**	**0.00**	**0.00%**	**16.98%**
Service Charge	1	3.37	3.37	1	3.57	3.57	0.20	5.93%	39.37%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.07%
Distribution Volumetric Rate	20	0.1281	2.56	20	0.1354	2.71	0.15	5.70%	29.86%
Volumetric Deferral/Variance Account Rider (including CBR Class	20	-0.0001	0.00	20	-0.0001	0.00	0.00	0.00%	-0.01%
Sub-Total: Distribution (excluding pass through)			**5.94**			**6.28**	**0.35**	**5.83%**	**69.29%**
Line Losses on Cost of Power	2	0.0770	0.14	2	0.0770	0.14	0.00	0.00%	1.56%
Sub-Total: Distribution			**6.08**			**6.42**	**0.35**	**5.69%**	**70.85%**
Retail Transmission Rate – Network Service Rate	22	0.004698	0.10	22	0.0047	0.10	0.00	0.00%	1.13%
Retail Transmission Rate – Line and Transformation Connection S	22	0.00429	0.09	22	0.0043	0.09	0.00	0.00%	1.03%
Sub-Total: Retail Transmission			**0.20**			**0.20**	**0.00**	**0.00%**	**2.16%**
Sub-Total: Delivery			**6.27**			**6.62**	**0.35**	**5.51%**	**73.01%**
Wholesale Market Service Rate	22	0.0036	0.08	22	0.0036	0.08	0.00	0.00%	0.87%
Rural Rate Protection Charge	22	0.0003	0.01	22	0.0003	0.01	0.00	0.00%	0.07%
Ontario Electricity Support Program Charge	22	0.0000	0.00	22	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	2.76%
Sub-Total: Regulatory			**0.34**			**0.34**	**0.00**	**0.00%**	**3.70%**
Debt Retirement Charge (DRC)	20	0.007	**0.14**	20	0.007	**0.14**	**0.00**	**0.00%**	**1.54%**
Total Electricity Charge on Two-Tier RPP (before HST)			**8.29**			**8.64**	**0.35**	**4.17%**	**95.24%**
HST		0.13	1.08		0.13	1.12	0.04	4.17%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**9.37**			**9.76**	**0.39**	**4.17%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-0.66		-0.08	-0.69	-0.03	-4.17%	-7.62%
Total Amount on Two-Tier RPP			**8.70**			**9.07**	**0.36**	**4.17%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	71
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	78
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	71	0.077	5.47	71	0.077	5.47	0.00	0.00%	24.91%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**5.47**			**5.47**	**0.00**	**0.00%**	**24.91%**
Service Charge	1	3.37	3.37	1	3.57	3.57	0.20	5.93%	16.27%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	71	0.1281	9.10	71	0.1354	9.61	0.52	5.70%	43.80%
Volumetric Deferral/Variance Account Rider (including CBR Class	71	-0.0001	0.00	71	-0.0001	0.00	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**12.47**			**13.19**	**0.72**	**5.76%**	**60.08%**
Line Losses on Cost of Power	7	0.0770	0.50	7	0.0770	0.50	0.00	0.00%	2.29%
Sub-Total: Distribution			**12.97**			**13.69**	**0.72**	**5.54%**	**62.37%**
Retail Transmission Rate – Network Service Rate	78	0.004698	0.36	78	0.0047	0.36	0.00	0.00%	1.66%
Retail Transmission Rate – Line and Transformation Connection S	78	0.00429	0.33	78	0.0043	0.33	0.00	0.00%	1.52%
Sub-Total: Retail Transmission			**0.70**			**0.70**	**0.00**	**0.00%**	**3.18%**
Sub-Total: Delivery			**13.67**			**14.38**	**0.72**	**5.26%**	**65.55%**
Wholesale Market Service Rate	78	0.0036	0.28	78	0.0036	0.28	0.00	0.00%	1.27%
Rural Rate Protection Charge	78	0.0003	0.02	78	0.0003	0.02	0.00	0.00%	0.11%
Ontario Electricity Support Program Charge	78	0.0000	0.00	78	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.14%
Sub-Total: Regulatory			**0.55**			**0.55**	**0.00**	**0.00%**	**2.52%**
Debt Retirement Charge (DRC)	71	0.007	**0.50**	71	0.007	**0.50**	**0.00**	**0.00%**	**2.26%**
Total Electricity Charge on Two-Tier RPP (before HST)			**20.18**			**20.90**	**0.72**	**3.56%**	**95.24%**
HST		0.13	2.62		0.13	2.72	0.09	3.56%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**22.81**			**23.62**	**0.81**	**3.56%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.61		-0.08	-1.67	-0.06	-3.56%	-7.62%
Total Amount on Two-Tier RPP			**21.19**			**21.95**	**0.75**	**3.56%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	200
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	218
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	200	0.077	15.40	200	0.077	15.40	0.00	0.00%	28.25%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15.40**			**15.40**	**0.00**	**0.00%**	**28.25%**
Service Charge	1	3.37	3.37	1	3.57	3.57	0.20	5.93%	6.55%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	200	0.1281	25.62	200	0.1354	27.08	1.46	5.70%	49.67%
Volumetric Deferral/Variance Account Rider (including CBR Class	200	-0.0001	-0.01	200	-0.0001	-0.01	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**28.98**			**30.64**	**1.66**	**5.73%**	**56.21%**
Line Losses on Cost of Power	18	0.0770	1.42	18	0.0770	1.42	0.00	0.00%	2.60%
Sub-Total: Distribution			**30.40**			**32.06**	**1.66**	**5.46%**	**58.80%**
Retail Transmission Rate – Network Service Rate	218	0.004698	1.03	218	0.0047	1.03	0.00	0.00%	1.88%
Retail Transmission Rate – Line and Transformation Connection S	218	0.00429	0.94	218	0.0043	0.94	0.00	0.00%	1.72%
Sub-Total: Retail Transmission			**1.96**			**1.96**	**0.00**	**0.00%**	**3.60%**
Sub-Total: Delivery			**32.36**			**34.02**	**1.66**	**5.13%**	**62.40%**
Wholesale Market Service Rate	218	0.0036	0.79	218	0.0036	0.79	0.00	0.00%	1.44%
Rural Rate Protection Charge	218	0.0003	0.07	218	0.0003	0.07	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	218	0.0000	0.00	218	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.46%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	**0.00%**	**2.02%**
Debt Retirement Charge (DRC)	200	0.007	**1.40**	200	0.007	**1.40**	**0.00**	**0.00%**	**2.57%**
Total Electricity Charge on Two-Tier RPP (before HST)			**50.27**			**51.93**	**1.66**	**3.30%**	**95.24%**
HST		0.13	6.53		0.13	6.75	0.22	3.30%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**56.80**			**58.68**	**1.88**	**3.30%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.02		-0.08	-4.15	-0.13	-3.30%	-7.62%
Total Amount on Two-Tier RPP			**52.78**			**54.52**	**1.74**	**3.30%**	**100.00%**

2020 Bill Impacts (Low Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	28.72%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**28.72%**
Service Charge	1	4.20	4.20	1	4.33	4.33	0.13	3.10%	16.15%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	100	0.1011	10.11	100	0.1043	10.43	0.32	3.17%	38.91%
Volumetric Deferral/Variance Account Rider (including CBR Class	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**14.32**			**14.77**	**0.45**	**3.14%**	**55.08%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	2.64%
Sub-Total: Distribution			**15.02**			**15.47**	**0.45**	**3.00%**	**57.72%**
Retail Transmission Rate – Network Service Rate	109	0.0047	0.51	109	0.0047	0.51	0.00	0.00%	1.91%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0043	0.47	109	0.0043	0.47	0.00	0.00%	1.75%
Sub-Total: Retail Transmission			**0.98**			**0.98**	**0.00**	**0.00%**	**3.66%**
Sub-Total: Delivery			**16.01**			**16.46**	**0.45**	**2.81%**	**61.38%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	1.47%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.93%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**2.52%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**2.61%**
Total Electricity Charge on Two-Tier RPP (before HST)			**25.08**			**25.53**	**0.45**	**1.79%**	**95.24%**
HST		0.13	3.26		0.13	3.32	0.06	1.79%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**28.34**			**28.85**	**0.51**	**1.79%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-2.01		-0.08	-2.04	-0.04	-1.79%	-7.62%
Total Amount on Two-Tier RPP			**26.34**			**26.81**	**0.47**	**1.79%**	**100.00%**

2020 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	517
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	565
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	517	0.077	39.81	517	0.077	39.81	0.00	0.00%	33.59%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**39.81**			**39.81**	**0.00**	**0.00%**	**33.59%**
Service Charge	1	4.20	4.20	1	4.33	4.33	0.13	3.10%	3.65%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	517	0.1011	52.27	517	0.1043	53.92	1.65	3.17%	45.50%
Volumetric Deferral/Variance Account Rider (including CBR Class	517	0.0000	-0.01	517	0.0000	-0.01	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**56.47**			**58.25**	**1.78**	**3.16%**	**49.15%**
Line Losses on Cost of Power	48	0.0770	3.66	48	0.0770	3.66	0.00	0.00%	3.09%
Sub-Total: Distribution			**60.13**			**61.92**	**1.78**	**2.97%**	**52.24%**
Retail Transmission Rate – Network Service Rate	565	0.0047	2.65	565	0.0047	2.65	0.00	0.00%	2.24%
Retail Transmission Rate – Line and Transformation Connection S	565	0.0043	2.42	565	0.0043	2.42	0.00	0.00%	2.04%
Sub-Total: Retail Transmission			**5.07**			**5.07**	**0.00**	**0.00%**	**4.28%**
Sub-Total: Delivery			**65.21**			**66.99**	**1.78**	**2.74%**	**56.53%**
Wholesale Market Service Rate	565	0.0036	2.03	565	0.0036	2.03	0.00	0.00%	1.71%
Rural Rate Protection Charge	565	0.0003	0.17	565	0.0003	0.17	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	565	0.0000	0.00	565	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%
Sub-Total: Regulatory			**2.45**			**2.45**	**0.00**	**0.00%**	**2.07%**
Debt Retirement Charge (DRC)	517	0.007	**3.62**	517	0.007	**3.62**	**0.00**	**0.00%**	**3.05%**
Total Electricity Charge on Two-Tier RPP (before HST)			**111.09**			**112.87**	**1.78**	**1.61%**	**95.24%**
HST		0.13	14.44		0.13	14.67	0.23	1.61%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**125.53**			**127.54**	**2.02**	**1.61%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.89		-0.08	-9.03	-0.14	-1.61%	-7.62%
Total Amount on Two-Tier RPP			**116.64**			**118.52**	**1.87**	**1.61%**	**100.00%**

2020 Bill Impacts (High Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2184
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.44%
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	24.23%
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**36.67%**
Service Charge	1	4.20	4.20	1	4.33	4.33	0.13	3.10%	0.93%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.1011	202.20	2,000	0.1043	208.60	6.40	3.17%	44.93%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	-0.02	2,000	0.0000	-0.02	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**206.39**			**212.92**	**6.53**	**3.16%**	**45.86%**
Line Losses on Cost of Power	184	0.0900	16.56	184	0.0900	16.56	0.00	0.00%	3.57%
Sub-Total: Distribution			**222.95**			**229.48**	**6.53**	**2.93%**	**49.43%**
Retail Transmission Rate – Network Service Rate	2,184	0.0047	10.26	2,184	0.0047	10.26	0.00	0.00%	2.21%
Retail Transmission Rate – Line and Transformation Connection S	2,184	0.0043	9.37	2,184	0.0043	9.37	0.00	0.00%	2.02%
Sub-Total: Retail Transmission			**19.63**			**19.63**	**0.00**	**0.00%**	**4.23%**
Sub-Total: Delivery			**242.58**			**249.11**	**6.53**	**2.69%**	**53.66%**
Wholesale Market Service Rate	2,184	0.0036	7.86	2,184	0.0036	7.86	0.00	0.00%	1.69%
Rural Rate Protection Charge	2,184	0.0003	0.66	2,184	0.0003	0.66	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	2,184	0.0000	0.00	2,184	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**8.77**			**8.77**	**0.00**	**0.00%**	**1.89%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.02%**
Total Electricity Charge on Two-Tier RPP (before HST)			**435.59**			**442.12**	**6.53**	**1.50%**	**95.24%**
HST		0.13	56.63		0.13	57.48	0.85	1.50%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**492.22**			**499.60**	**7.38**	**1.50%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-34.85		-0.08	-35.37	-0.52	-1.50%	-7.62%
Total Amount on Two-Tier RPP			**457.37**			**464.23**	**6.86**	**1.50%**	**100.00%**

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2020 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$77.72	$0.82	2.29%	$0.76	0.97%
	Typical	750		$122.28	$0.82	2.29%	$0.64	0.52%
	Average	755		$0.64	$0.82	2.29%	$0.64	0.52%
	High	1,400		$194.67	$0.82	2.28%	$0.45	0.23%
R1	Low	400		$84.23	$0.00	0.00%	($0.06)	-0.07%
	Typical	750		$123.50	$0.00	0.00%	($0.12)	-0.10%
	Average	920		$142.58	$0.00	0.00%	($0.14)	-0.10%
	High	1,800		$241.32	$0.00	0.00%	($0.28)	-0.12%
R2	Low	450		$90.72	$0.00	0.00%	($0.04)	-0.04%
	Typical	750		$124.98	$0.00	0.00%	($0.06)	-0.05%
	Average	1,152		$170.90	$0.00	0.00%	($0.09)	-0.05%
	High	2,300		$302.01	$0.00	0.00%	($0.19)	-0.06%
Seasonal	Low	50		$61.54	$4.71	9.02%	$4.95	8.04%
	Average	352		$109.26	$1.03	1.57%	$1.09	0.99%
	High	1,000		$211.65	($6.88)	-7.32%	($7.20)	-3.40%
GSe	Low	1,000		$218.09	$2.40	2.55%	$2.33	1.07%
	Typical	2,000		$402.67	$4.30	2.73%	$4.13	1.03%
	Average	1,982		$399.34	$4.27	2.73%	$4.10	1.03%
	High	15,000		$2,802.13	$29.00	2.96%	$27.57	0.98%
UGe	Low	1,000		$174.70	$1.35	2.45%	$1.13	0.65%
	Typical	2,000		$321.95	$2.25	2.65%	$1.78	0.55%
	Average	2,759		$433.71	$2.93	2.72%	$2.28	0.53%
	High	15,000		$2,236.15	$13.95	2.94%	$10.31	0.46%
GSd	Low	15,000	60	$3,109.89	$31.89	2.70%	$31.55	1.01%
	Average	36,104	128	$6,928.65	$66.44	2.77%	$65.51	0.95%
	High	175,000	500	$30,278.95	$255.45	2.81%	$251.29	0.83%
UGd	Low	15,000	60	$2,642.92	$19.69	2.72%	$17.35	0.66%
	Average	50,525	138	$7,589.01	$43.13	2.82%	$37.46	0.49%
	High	175,000	500	$26,346.75	$151.91	2.89%	$130.80	0.50%
St Lgt	Low	100		$26.81	$0.70	4.74%	$0.56	2.09%
	Average	517		$118.52	$1.78	3.06%	$0.97	0.82%
	High	2,000		$464.23	$5.64	2.65%	$2.42	0.52%
Sen Lgt	Low	20		$9.07	$0.21	3.31%	$0.18	2.02%
	Average	71		$21.95	$0.36	2.70%	$0.25	1.14%
	High	200		$54.52	$0.73	2.38%	$0.42	0.76%
USL	Low	100		$52.88	$0.76	1.92%	$0.79	1.49%
	Average	364		$90.17	$0.89	1.88%	$0.91	1.01%
	High	1,000		$184.67	$1.21	1.82%	$1.20	0.65%
DGen	Low	300	10	$387.06	$7.65	2.53%	$8.82	2.28%
	Average	1,328	12	$521.63	$9.18	2.83%	$10.58	2.03%
	High	5,000	100	$2,082.81	$76.52	6.07%	$88.19	4.23%
ST	Low	200,000	500	$26,072.51	$32.44	1.71%	$92.76	0.36%
	Average	1,601,036	2,960	$190,063.33	$121.02	2.40%	$468.85	0.25%
	High	4,000,000	10,000	$494,398.04	$374.52	2.67%	$1,545.15	0.31%

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2020 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Commodity Price Used
WHSI to HONI									
AUR	**Low**	**350**		$70.14	$1.10	3.71%	$1.94	2.77%	TOU
	Typical	**750**		$113.44	$1.10	3.71%	$2.85	2.51%	
	Average	**600**		$97.20	$1.10	3.71%	$2.51	2.58%	
	High	**1,400**		$183.80	$1.10	3.71%	$4.31	2.35%	
AUGe	**Low**	**1,000**		$156.78	$8.42	21.46%	$8.54	5.45%	TOU
	Typical	**2,000**		$286.28	$11.52	21.52%	$11.49	4.01%	
	Average	**2,695**		$376.29	$13.67	21.54%	$13.54	3.60%	
	High	**15,000**		$1,969.81	$51.82	21.64%	$49.86	2.53%	
AUGd	**Low**	**15,000**	**60**	$2,220.57	$150.66	51.65%	$61.53	2.77%	RPP Tier 1 (assumed RPP Tier 1 price is close to WAHSP)
	Average	**61,239**	**177**	$7,999.21	$309.46	52.43%	$34.26	0.43%	
	High	**175,000**	**500**	$22,517.81	$747.87	52.87%	($45.32)	-0.20%	
St Lgt	**Average**	**76,826**	**210.8**	$14,610.42	$3,139.22	61.83%	$3,500.58	23.96%	Two-tier RPP
USL	**Average**	**1,545**		$210.73	$55.10	189.26%	$60.46	28.69%	Two-tier RPP
ST	**Low**	**750,000**	**1,500**	$81,691.01	$1,373.82	73.47%	$9,289.84	11.37%	RPP Tier 1 (assumed RPP Tier 1 price is close to WAHSP)
	Average	**1,037,334**	**2,075**	$124,884.52	($2,143.32)	-34.90%	$403.76	0.32%	
	High	**2,000,000**	**3,500**	$235,854.39	($4,137.39)	-41.34%	$122.91	0.05%	
NPDI to HONI									
AR	**Low**	**400**		$82.31	$3.84	10.49%	$5.66	6.88%	TOU
	Typical	**750**		$120.09	$3.53	9.55%	$6.75	5.62%	
	Average	**570**		$100.66	$3.69	10.03%	$6.19	6.15%	
	High	**1,800**		$233.43	$2.58	6.82%	$10.03	4.30%	
AGSe	**Low**	**1,000**		$183.82	($5.62)	-8.60%	($5.42)	-2.95%	TOU
	Typical	**2,000**		$313.08	($2.92)	-3.59%	($0.33)	-0.11%	
	Average	**2,182**		$336.82	($2.43)	-2.88%	$0.44	0.13%	
	High	**15,000**		$2,004.91	$32.18	11.07%	$54.32	2.71%	
AGSd	**Low**	**15,000**	**60**	$2,382.69	$21.87	4.42%	($4.27)	-0.18%	RPP Tier 1 (assumed RPP Tier 1 price is close to WAHSP)
	Average	**57,223**	**161**	$7,705.81	$118.76	12.92%	$56.28	0.73%	
	High	**175,000**	**500**	$23,072.99	$444.14	18.94%	$259.87	1.13%	
St Lgt	**Average**	**1,368**	**4**	$230.51	$79.05	109.93%	$87.04	37.76%	Two-tier RPP
Sen Lgt	**Average**	**126**	**0.5**	$29.89	$5.90	38.71%	$6.27	20.97%	Two-tier RPP
USL	**Average**	**945**		$130.66	$41.88	173.37%	$46.65	35.70%	Two-tier RPP
HCHI to HONI									
AR	**Low**	**400**		$82.15	$5.01	14.14%	$5.82	7.09%	TOU
	Typical	**750**		$120.68	$4.87	13.70%	$6.16	5.11%	
	Average	**694**		$114.52	$4.89	13.77%	$6.11	5.33%	
	High	**1,800**		$236.26	$4.45	12.37%	$7.19	3.04%	
AGSe	**Low**	**1,000**		$165.05	$13.85	30.19%	$13.35	8.09%	TOU
	Typical	**2,000**		$301.00	$13.45	20.67%	$11.75	3.90%	
	Average	**1,819**		$276.45	$13.52	21.95%	$12.04	4.35%	
	High	**15,000**		$2,068.39	$8.25	2.62%	($9.16)	-0.44%	
AGSd	**Low**	**15,000**	**60**	$2,261.41	$190.48	58.48%	$117.02	5.17%	RPP Tier 1 (assumed RPP Tier 1 price is close to WAHSP)
	Average	**50,917**	**143**	$6,859.29	$283.43	42.77%	$73.11	1.07%	
	High	**175,000**	**500**	$23,422.83	$681.96	32.36%	($89.98)	-0.38%	
St Lgt	**Average**	**105,612**	**274.1**	$27,946.23	($3,113.00)	-21.61%	($3,047.56)	-10.91%	Two-tier RPP
Sen Lgt	**Average**	**131**	**0.3**	$42.11	($4.65)	-17.55%	($4.67)	-11.09%	Two-tier RPP
USL	**Average**	**551**		$82.79	$33.18	158.83%	$34.75	41.97%	Two-tier RPP

2021 Bill Impacts (Low Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	370
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	35.24%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**35.24%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		18.84%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.20%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		10.60%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**37.60%**	**36.64%**
Service Charge	1	35.85	35.85	1	36.67	36.67	0.82	2.29%	47.95%	46.72%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	350	0.0000	0.00	350	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	350	0.0000	0.01	350	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**35.87**			**36.69**	**0.82**	**2.29%**	**47.97%**	**46.75%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.03%	1.01%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	2.01%	1.96%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.14%	2.09%
Sub-Total: Distribution (based on two-tier RPP prices)			**38.19**			**39.01**	**0.82**	**2.15%**	**51.01%**	**49.71%**
Sub-Total: Distribution (based on TOU prices)			**38.30**			**39.12**	**0.82**	**2.14%**	**51.15%**	**49.84%**
Retail Transmission Rate – Network Service Rate	370	0.0078	2.90	370	0.0077	2.85	-0.05	-1.64%	3.72%	3.63%
Retail Transmission Rate – Line and Transformation Connection Service Rate	370	0.0064	2.38	370	0.0063	2.33	-0.05	-2.14%	3.05%	2.97%
Sub-Total: Retail Transmission			**5.28**			**5.18**	**-0.10**	**-1.86%**	**6.77%**	**6.60%**
Sub-Total: Delivery (based on two-tier RPP prices)			**43.47**			**44.19**	**0.72**	**1.66%**	**57.79%**	**56.31%**
Sub-Total: Delivery (based on TOU prices)			**43.57**			**44.30**	**0.72**	**1.66%**	**57.92%**	**56.44%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.74%	1.70%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.15%	0.14%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.33%	0.32%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.21%**	**2.16%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**72.11**			**72.84**	**0.72**	**1.00%**	**95.24%**	
HST		0.13	9.37		0.13	9.47	0.09	1.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**81.49**			**82.30**	**0.82**	**1.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.77		-0.08	-5.83	-0.06	-1.00%	-7.62%	
Total Amount on Two-Tier RPP			**75.72**			**76.48**	**0.76**	**1.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**74.02**			**74.74**	**0.72**	**0.97%**		**95.24%**
HST		0.13	9.62		0.13	9.72	0.09	0.97%		12.38%
Total Electricity Charge on TOU (including HST)			**83.65**			**84.46**	**0.82**	**0.97%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.92		-0.08	-5.98	-0.06	-0.97%		-7.62%
Total Amount on TOU			**77.72**			**78.48**	**0.76**	**0.97%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	793
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.10%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.13%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**49.24%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.78%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.85%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.50%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.82%**	**50.13%**
Service Charge	1	35.85	35.85	1	36.67	36.67	0.82	2.29%	30.24%	29.83%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**35.88**			**36.70**	**0.82**	**2.29%**	**30.27%**	**29.86%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.17%	3.13%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	2.90%	2.86%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.52**			**41.34**	**0.82**	**2.02%**	**34.09%**	**33.63%**
Sub-Total: Distribution (based on TOU prices)			**40.18**			**41.00**	**0.82**	**2.04%**	**33.82%**	**33.36%**
Retail Transmission Rate – Network Service Rate	793	0.0078	6.21	793	0.0077	6.10	-0.10	-1.64%	5.03%	4.97%
Retail Transmission Rate – Line and Transformation Connection Service Rate	793	0.0064	5.10	793	0.0063	4.99	-0.11	-2.14%	4.12%	4.06%
Sub-Total: Retail Transmission			**11.31**			**11.10**	**-0.21**	**-1.86%**	**9.15%**	**9.03%**
Sub-Total: Delivery (based on two-tier RPP prices)			**51.83**			**52.44**	**0.61**	**1.18%**	**43.25%**	**42.66%**
Sub-Total: Delivery (based on TOU prices)			**51.49**			**52.10**	**0.61**	**1.18%**	**42.97%**	**42.39%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.35%	2.32%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.20%	0.19%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.76%**	**2.72%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**114.87**			**115.48**	**0.61**	**0.53%**	**95.24%**	
HST		0.13	14.93		0.13	15.01	0.08	0.53%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**129.80**			**130.49**	**0.69**	**0.53%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.19		-0.08	-9.24	-0.05	-0.53%	-7.62%	
Total Amount on Two-Tier RPP			**120.61**			**121.25**	**0.64**	**0.53%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**116.45**			**117.06**	**0.61**	**0.52%**		**95.24%**
HST		0.13	15.14		0.13	15.22	0.08	0.52%		12.38%
Total Electricity Charge on TOU (including HST)			**131.59**			**132.28**	**0.69**	**0.52%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.32		-0.08	-9.36	-0.05	-0.52%		-7.62%
Total Amount on TOU			**122.28**			**122.92**	**0.64**	**0.52%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	755
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	798
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.92%	
Energy Second Tier (kWh)	155	0.090	13.95	155	0.090	13.95	0.00	0.00%	11.45%	
Sub-Total: Energy (RPP)			**60.15**			**60.15**	**0.00**	**0.00%**	**49.36%**	
TOU-Off Peak	491	0.065	31.90	491	0.065	31.90	0.00	0.00%		25.84%
TOU-Mid Peak	128	0.095	12.19	128	0.095	12.19	0.00	0.00%		9.88%
TOU-On Peak	136	0.132	17.94	136	0.132	17.94	0.00	0.00%		14.53%
Sub-Total: Energy (TOU)			**62.03**			**62.03**	0.00	0.00%	**50.91%**	**50.24%**
Service Charge	1	35.85	35.85	1	36.67	36.67	0.82	2.29%	30.09%	29.70%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	755	0.0000	0.00	755	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	755	0.0000	0.02	755	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**35.88**			**36.70**	**0.82**	**2.29%**	**30.12%**	**29.72%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.87	43	0.0900	3.87	0.00	0.00%	3.18%	3.14%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	43	0.0822	3.54	0.00	0.00%	2.90%	2.86%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.54**			**41.36**	**0.82**	**2.02%**	**33.95%**	**33.50%**
Sub-Total: Distribution (based on TOU prices)			**40.21**			**41.03**	**0.82**	**2.04%**	**33.67%**	**33.23%**
Retail Transmission Rate – Network Service Rate	798	0.0078	6.25	798	0.0077	6.14	-0.10	-1.64%	5.04%	4.98%
Retail Transmission Rate – Line and Transformation Connection Service Rate	798	0.0064	5.14	798	0.0063	5.03	-0.11	-2.14%	4.13%	4.07%
Sub-Total: Retail Transmission			**11.38**			**11.17**	**-0.21**	**-1.86%**	**9.17%**	**9.05%**
Sub-Total: Delivery (based on two-tier RPP prices)			**51.93**			**52.54**	**0.61**	**1.17%**	**43.11%**	**42.55%**
Sub-Total: Delivery (based on TOU prices)			**51.59**			**52.20**	**0.61**	**1.18%**	**42.84%**	**42.28%**
Wholesale Market Service Rate	798	0.0036	2.87	798	0.0036	2.87	0.00	0.00%	2.36%	2.33%
Rural Rate Protection Charge	798	0.0003	0.24	798	0.0003	0.24	0.00	0.00%	0.20%	0.19%
Ontario Electricity Support Program Charge	798	0.0000	0.00	798	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.36**			**3.36**	**0.00**	**0.00%**	**2.76%**	**2.72%**
Debt Retirement Charge (DRC)	755	0.000	**0.00**	755	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**115.44**			**116.05**	**0.61**	**0.53%**	**95.24%**	
HST		0.13	15.01		0.13	15.09	0.08	0.53%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**130.45**			**131.13**	**0.69**	**0.53%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.24		-0.08	-9.28	-0.05	-0.53%	-7.62%	
Total Amount on Two-Tier RPP			**121.21**			**121.85**	**0.64**	**0.53%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**116.98**			**117.59**	**0.61**	**0.52%**		**95.24%**
HST		0.13	15.21		0.13	15.29	0.08	0.52%		12.38%
Total Electricity Charge on TOU (including HST)			**132.19**			**132.88**	**0.69**	**0.52%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.36		-0.08	-9.41	-0.05	-0.52%		-7.62%
Total Amount on TOU			**122.83**			**123.47**	**0.64**	**0.52%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1480
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.20%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	36.16%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**59.36%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		30.31%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.59%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		17.05%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**57.77%**	**58.95%**
Service Charge	1	35.85	35.85	1	36.67	36.67	0.82	2.29%	18.42%	18.79%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,400	0.0000	0.04	1,400	0.0000	0.04	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**35.90**			**36.72**	**0.82**	**2.28%**	**18.44%**	**18.82%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.40%	0.40%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.61%	3.68%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.29%	3.36%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.87**			**44.69**	**0.82**	**1.87%**	**22.45%**	**22.90%**
Sub-Total: Distribution (based on TOU prices)			**43.25**			**44.07**	**0.82**	**1.90%**	**22.13%**	**22.58%**
Retail Transmission Rate – Network Service Rate	1,480	0.0078	11.58	1,480	0.0077	11.39	-0.19	-1.64%	5.72%	5.84%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,480	0.0064	9.53	1,480	0.0063	9.32	-0.20	-2.14%	4.68%	4.78%
Sub-Total: Retail Transmission			**21.11**			**20.72**	**-0.39**	**-1.86%**	**10.40%**	**10.62%**
Sub-Total: Delivery (based on two-tier RPP prices)			**64.98**			**65.41**	**0.43**	**0.66%**	**32.85%**	**33.52%**
Sub-Total: Delivery (based on TOU prices)			**64.36**			**64.78**	**0.43**	**0.66%**	**32.54%**	**33.20%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.68%	2.73%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**3.02%**	**3.09%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**189.20**			**189.63**	**0.43**	**0.23%**	**95.24%**	
HST		0.13	24.60		0.13	24.65	0.06	0.23%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**213.80**			**214.28**	**0.48**	**0.23%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.14		-0.08	-15.17	-0.03	-0.23%	-7.62%	
Total Amount on Two-Tier RPP			**198.66**			**199.11**	**0.45**	**0.23%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**185.40**			**185.83**	**0.43**	**0.23%**		**95.24%**
HST		0.13	24.10		0.13	24.16	0.06	0.23%		12.38%
Total Electricity Charge on TOU (including HST)			**209.50**			**209.99**	**0.48**	**0.23%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.83		-0.08	-14.87	-0.03	-0.23%		-7.62%
Total Amount on TOU			**194.67**			**195.12**	**0.45**	**0.23%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	430
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	37.64%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**37.64%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		20.08%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.68%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		11.29%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**40.16%**	**39.05%**
Service Charge	1	47.06	36.43	1	52.31	36.43	0.00	0.00%	44.52%	43.28%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0160	0.00	400	0.0116	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	400	0.0000	0.01	400	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.44**			**36.44**	**0.00**	**0.00%**	**44.53%**	**43.30%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.97%	0.94%
Line Losses on Cost of Power (based on two-tier RPP prices)	30	0.0770	2.34	30	0.0770	2.34	0.00	0.00%	2.86%	2.78%
Line Losses on Cost of Power (based on TOU prices)	30	0.0822	2.50	30	0.0822	2.50	0.00	0.00%	3.05%	2.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.57**			**39.57**	**0.00**	**0.00%**	**48.36%**	**47.02%**
Sub-Total: Distribution (based on TOU prices)			**39.73**			**39.73**	**0.00**	**0.00%**	**48.55%**	**47.20%**
Retail Transmission Rate – Network Service Rate	430	0.0072	3.10	430	0.0072	3.10	0.00	-0.10%	3.79%	3.68%
Retail Transmission Rate – Line and Transformation Connection Service Rate	430	0.0060	2.60	430	0.0059	2.54	-0.06	-2.19%	3.10%	3.02%
Sub-Total: Retail Transmission			**5.70**			**5.64**	**-0.06**	**-1.05%**	**6.89%**	**6.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.27**			**45.21**	**-0.06**	**-0.13%**	**55.25%**	**53.71%**
Sub-Total: Delivery (based on TOU prices)			**45.43**			**45.37**	**-0.06**	**-0.13%**	**55.44%**	**53.90%**
Wholesale Market Service Rate	430	0.0036	1.55	430	0.0036	1.55	0.00	0.00%	1.89%	1.84%
Rural Rate Protection Charge	430	0.0003	0.13	430	0.0003	0.13	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	430	0.0000	0.00	430	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%	0.30%
Sub-Total: Regulatory			**1.93**			**1.93**	**0.00**	**0.00%**	**2.36%**	**2.29%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**78.00**			**77.94**	**-0.06**	**-0.08%**	**95.24%**	
HST		0.13	10.14		0.13	10.13	-0.01	-0.08%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**88.14**			**88.07**	**-0.07**	**-0.08%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.24		-0.08	-6.24	0.00	0.08%	-7.62%	
Total Amount on Two-Tier RPP			**81.90**			**81.84**	**-0.06**	**-0.08%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**80.22**			**80.16**	**-0.06**	**-0.07%**		**95.24%**
HST		0.13	10.43		0.13	10.42	-0.01	-0.07%		12.38%
Total Electricity Charge on TOU (including HST)			**90.65**			**90.58**	**-0.07**	**-0.07%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.42		-0.08	-6.41	0.00	0.07%		-7.62%
Total Amount on TOU			**84.23**			**84.17**	**-0.06**	**-0.07%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	807
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.92%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.08%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**49.00%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.68%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.82%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.44%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.57%**	**49.94%**
Service Charge	1	47.06	36.43	1	52.31	36.43	0.00	0.00%	29.90%	29.53%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0160	0.00	750	0.0116	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**29.92%**	**29.54%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	4.21%	4.16%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	3.84%	3.80%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.37**			**42.37**	**0.00**	**0.00%**	**34.77%**	**34.34%**
Sub-Total: Distribution (based on TOU prices)			**41.92**			**41.92**	**0.00**	**0.00%**	**34.41%**	**33.98%**
Retail Transmission Rate – Network Service Rate	807	0.0072	5.82	807	0.0072	5.81	-0.01	-0.10%	4.77%	4.71%
Retail Transmission Rate – Line and Transformation Connection Service Rate	807	0.0060	4.87	807	0.0059	4.76	-0.11	-2.19%	3.91%	3.86%
Sub-Total: Retail Transmission			**10.68**			**10.57**	**-0.11**	**-1.05%**	**8.68%**	**8.57%**
Sub-Total: Delivery (based on two-tier RPP prices)			**53.05**			**52.94**	**-0.11**	**-0.21%**	**43.45%**	**42.91%**
Sub-Total: Delivery (based on TOU prices)			**52.61**			**52.49**	**-0.11**	**-0.21%**	**43.08%**	**42.54%**
Wholesale Market Service Rate	807	0.0036	2.91	807	0.0036	2.91	0.00	0.00%	2.38%	2.35%
Rural Rate Protection Charge	807	0.0003	0.24	807	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	807	0.0000	0.00	807	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.40**			**3.40**	**0.00**	**0.00%**	**2.79%**	**2.75%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**116.15**			**116.04**	**-0.11**	**-0.10%**	**95.24%**	
HST		0.13	15.10		0.13	15.08	-0.01	-0.10%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**131.25**			**131.12**	**-0.13**	**-0.10%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.29		-0.08	-9.28	0.01	0.10%	-7.62%	
Total Amount on Two-Tier RPP			**121.96**			**121.84**	**-0.12**	**-0.10%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.62**			**117.51**	**-0.11**	**-0.10%**		**95.24%**
HST		0.13	15.29		0.13	15.28	-0.01	-0.10%		12.38%
Total Electricity Charge on TOU (including HST)			**132.91**			**132.79**	**-0.13**	**-0.10%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.40	0.01	0.10%		-7.62%
Total Amount on TOU			**123.50**			**123.39**	**-0.12**	**-0.10%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1937
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.57%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.41%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.98%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.55%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		12.06%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.74%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**59.44%**	**61.35%**
Service Charge	1	47.06	36.43	1	52.31	36.43	0.00	0.00%	14.64%	15.11%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0160	0.00	1,800	0.0116	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,800	0.0000	0.04	1,800	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.47**			**36.47**	**0.00**	**0.00%**	**14.66%**	**15.13%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.32%	0.33%
Line Losses on Cost of Power (based on two-tier RPP prices)	137	0.0900	12.31	137	0.0900	12.31	0.00	0.00%	4.95%	5.11%
Line Losses on Cost of Power (based on TOU prices)	137	0.0822	11.24	137	0.0822	11.24	0.00	0.00%	4.52%	4.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.57**			**49.57**	**0.00**	**0.00%**	**19.92%**	**20.57%**
Sub-Total: Distribution (based on TOU prices)			**48.50**			**48.50**	**0.00**	**0.00%**	**19.49%**	**20.12%**
Retail Transmission Rate – Network Service Rate	1,937	0.0072	13.96	1,937	0.0072	13.94	-0.01	-0.10%	5.61%	5.79%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,937	0.0060	11.68	1,937	0.0059	11.43	-0.26	-2.19%	4.59%	4.74%
Sub-Total: Retail Transmission			**25.64**			**25.37**	**-0.27**	**-1.05%**	**10.20%**	**10.53%**
Sub-Total: Delivery (based on two-tier RPP prices)			**75.21**			**74.94**	**-0.27**	**-0.36%**	**30.12%**	**31.09%**
Sub-Total: Delivery (based on TOU prices)			**74.14**			**73.87**	**-0.27**	**-0.36%**	**29.69%**	**30.65%**
Wholesale Market Service Rate	1,937	0.0036	6.97	1,937	0.0036	6.97	0.00	0.00%	2.80%	2.89%
Rural Rate Protection Charge	1,937	0.0003	0.58	1,937	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,937	0.0000	0.00	1,937	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.80**			**7.80**	**0.00**	**0.00%**	**3.14%**	**3.24%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**237.22**			**236.95**	**-0.27**	**-0.11%**	**95.24%**	
HST		0.13	30.84		0.13	30.80	-0.03	-0.11%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**268.06**			**267.75**	**-0.30**	**-0.11%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.98		-0.08	-18.96	0.02	0.11%	-7.62%	
Total Amount on Two-Tier RPP			**249.08**			**248.79**	**-0.28**	**-0.11%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**229.83**			**229.56**	**-0.27**	**-0.12%**		**95.24%**
HST		0.13	29.88		0.13	29.84	-0.03	-0.12%		12.38%
Total Electricity Charge on TOU (including HST)			**259.71**			**259.41**	**-0.30**	**-0.12%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.39		-0.08	-18.37	0.02	0.12%		-7.62%
Total Amount on TOU			**241.32**			**241.04**	**-0.28**	**-0.12%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	920
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	990
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	32.45%	
Energy Second Tier (kWh)	320	0.090	28.80	320	0.090	28.80	0.00	0.00%	20.23%	
Sub-Total: Energy (RPP)			**75.00**			**75.00**	**0.00**	**0.00%**	**52.67%**	
TOU-Off Peak	598	0.065	38.87	598	0.065	38.87	0.00	0.00%		27.29%
TOU-Mid Peak	156	0.095	14.86	156	0.095	14.86	0.00	0.00%		10.43%
TOU-On Peak	166	0.132	21.86	166	0.132	21.86	0.00	0.00%		15.35%
Sub-Total: Energy (TOU)			**75.59**			**75.59**	0.00	0.00%	**53.08%**	**53.07%**
Service Charge	1	47.06	36.43	1	52.31	36.43	0.00	0.00%	25.58%	25.58%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	920	0.0160	0.00	920	0.0116	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	920	0.0000	0.02	920	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**25.60%**	**25.59%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.55%	0.55%
Line Losses on Cost of Power (based on two-tier RPP prices)	70	0.0900	6.29	70	0.0900	6.29	0.00	0.00%	4.42%	4.42%
Line Losses on Cost of Power (based on TOU prices)	70	0.0822	5.74	70	0.0822	5.74	0.00	0.00%	4.03%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.54**			**43.54**	**0.00**	**0.00%**	**30.57%**	**30.56%**
Sub-Total: Distribution (based on TOU prices)			**42.99**			**42.99**	**0.00**	**0.00%**	**30.19%**	**30.18%**
Retail Transmission Rate – Network Service Rate	990	0.0072	7.13	990	0.0072	7.13	-0.01	-0.10%	5.01%	5.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	990	0.0060	5.97	990	0.0059	5.84	-0.13	-2.19%	4.10%	4.10%
Sub-Total: Retail Transmission			**13.11**			**12.97**	**-0.14**	**-1.05%**	**9.11%**	**9.10%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.64**			**56.50**	**-0.14**	**-0.24%**	**39.68%**	**39.67%**
Sub-Total: Delivery (based on TOU prices)			**56.09**			**55.95**	**-0.14**	**-0.25%**	**39.30%**	**39.28%**
Wholesale Market Service Rate	990	0.0036	3.56	990	0.0036	3.56	0.00	0.00%	2.50%	2.50%
Rural Rate Protection Charge	990	0.0003	0.30	990	0.0003	0.30	0.00	0.00%	0.21%	0.21%
Ontario Electricity Support Program Charge	990	0.0000	0.00	990	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**4.11**			**4.11**	**0.00**	**0.00%**	**2.89%**	**2.89%**
Debt Retirement Charge (DRC)	920	0.000	**0.00**	920	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**135.75**			**135.61**	**-0.14**	**-0.10%**	**95.24%**	
HST		0.13	17.65		0.13	17.63	-0.02	-0.10%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**153.40**			**153.24**	**-0.16**	**-0.10%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.85	0.01	0.10%	-7.62%	
Total Amount on Two-Tier RPP			**142.54**			**142.39**	**-0.14**	**-0.10%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**135.79**			**135.65**	**-0.14**	**-0.10%**		**95.24%**
HST		0.13	17.65		0.13	17.63	-0.02	-0.10%		12.38%
Total Electricity Charge on TOU (including HST)			**153.44**			**153.29**	**-0.16**	**-0.10%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.86		-0.08	-10.85	0.01	0.10%		-7.62%
Total Amount on TOU			**142.58**			**142.44**	**-0.14**	**-0.10%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	450
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	497
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	450	0.077	34.65	450	0.077	34.65	0.00	0.00%	39.38%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**34.65**			**34.65**	**0.00**	**0.00%**	**39.38%**	
TOU-Off Peak	293	0.065	19.01	293	0.065	19.01	0.00	0.00%		20.97%
TOU-Mid Peak	77	0.095	7.27	77	0.095	7.27	0.00	0.00%		8.01%
TOU-On Peak	81	0.132	10.69	81	0.132	10.69	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**36.97**			**36.97**	0.00	0.00%	**42.02%**	**40.77%**
Service Charge	1	44.12	36.43	1	55.26	36.43	0.00	0.00%	41.40%	40.17%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	450	0.0269	0.00	450	0.0201	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	450	0.0000	0.00	450	0.0000	0.00	0.00	0.00%	0.01%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.41**			**36.41**	**0.00**	**0.00%**	**41.39%**	**40.16%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.90%	0.87%
Line Losses on Cost of Power (based on two-tier RPP prices)	47	0.0770	3.64	47	0.0770	3.64	0.00	0.00%	4.13%	4.01%
Line Losses on Cost of Power (based on TOU prices)	47	0.0822	3.88	47	0.0822	3.88	0.00	0.00%	4.41%	4.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.84**			**40.84**	**0.00**	**0.00%**	**46.42%**	**45.04%**
Sub-Total: Distribution (based on TOU prices)			**41.09**			**41.09**	**0.00**	**0.00%**	**46.70%**	**45.31%**
Retail Transmission Rate – Network Service Rate	497	0.0067	3.35	497	0.0068	3.38	0.03	0.89%	3.84%	3.73%
Retail Transmission Rate – Line and Transformation Connection Service Rate	497	0.0056	2.80	497	0.0055	2.73	-0.06	-2.31%	3.11%	3.02%
Sub-Total: Retail Transmission			**6.15**			**6.12**	**-0.03**	**-0.57%**	**6.95%**	**6.74%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.99**			**46.96**	**-0.03**	**-0.07%**	**53.37%**	**51.78%**
Sub-Total: Delivery (based on TOU prices)			**47.24**			**47.20**	**-0.03**	**-0.07%**	**53.65%**	**52.05%**
Wholesale Market Service Rate	497	0.0036	1.79	497	0.0036	1.79	0.00	0.00%	2.03%	1.97%
Rural Rate Protection Charge	497	0.0003	0.15	497	0.0003	0.15	0.00	0.00%	0.17%	0.16%
Ontario Electricity Support Program Charge	497	0.0000	0.00	497	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%	0.28%
Sub-Total: Regulatory			**2.19**			**2.19**	**0.00**	**0.00%**	**2.49%**	**2.41%**
Debt Retirement Charge (DRC)	450	0.000	**0.00**	450	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**83.83**			**83.80**	**-0.03**	**-0.04%**	**95.24%**	
HST		0.13	10.90		0.13	10.89	0.00	-0.04%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**94.73**			**94.69**	**-0.04**	**-0.04%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.71		-0.08	-6.70	0.00	0.04%	-7.62%	
Total Amount on Two-Tier RPP			**88.02**			**87.99**	**-0.04**	**-0.04%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**86.40**			**86.36**	**-0.03**	**-0.04%**		**95.24%**
HST		0.13	11.23		0.13	11.23	0.00	-0.04%		12.38%
Total Electricity Charge on TOU (including HST)			**97.63**			**97.59**	**-0.04**	**-0.04%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.91		-0.08	-6.91	0.00	0.04%		-7.62%
Total Amount on TOU			**90.72**			**90.68**	**-0.04**	**-0.04%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	829
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.39%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.93%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.32%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.37%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.70%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.27%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.87%**	**49.33%**
Service Charge	1	44.12	36.43	1	55.26	36.43	0.00	0.00%	29.49%	29.16%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	750	0.0269	0.00	750	0.0201	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	750	0.0000	0.01	750	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**29.47%**	**29.15%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.63%
Line Losses on Cost of Power (based on two-tier RPP prices)	79	0.0900	7.09	79	0.0900	7.09	0.00	0.00%	5.74%	5.67%
Line Losses on Cost of Power (based on TOU prices)	79	0.0822	6.47	79	0.0822	6.47	0.00	0.00%	5.24%	5.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.29**			**44.29**	**0.00**	**0.00%**	**35.85%**	**35.46%**
Sub-Total: Distribution (based on TOU prices)			**43.68**			**43.68**	**0.00**	**0.00%**	**35.35%**	**34.96%**
Retail Transmission Rate – Network Service Rate	829	0.0067	5.59	829	0.0068	5.64	0.05	0.89%	4.56%	4.51%
Retail Transmission Rate – Line and Transformation Connection Service Rate	829	0.0056	4.67	829	0.0055	4.56	-0.11	-2.31%	3.69%	3.65%
Sub-Total: Retail Transmission			**10.25**			**10.19**	**-0.06**	**-0.57%**	**8.25%**	**8.16%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.55**			**54.49**	**-0.06**	**-0.11%**	**44.10%**	**43.62%**
Sub-Total: Delivery (based on TOU prices)			**53.93**			**53.87**	**-0.06**	**-0.11%**	**43.60%**	**43.12%**
Wholesale Market Service Rate	829	0.0036	2.98	829	0.0036	2.98	0.00	0.00%	2.41%	2.39%
Rural Rate Protection Charge	829	0.0003	0.25	829	0.0003	0.25	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	829	0.0000	0.00	829	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.48**			**3.48**	**0.00**	**0.00%**	**2.82%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**117.73**			**117.67**	**-0.06**	**-0.05%**	**95.24%**	
HST		0.13	15.30		0.13	15.30	-0.01	-0.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**133.03**			**132.97**	**-0.07**	**-0.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.42		-0.08	-9.41	0.00	0.05%	-7.62%	
Total Amount on Two-Tier RPP			**123.61**			**123.55**	**-0.06**	**-0.05%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**119.03**			**118.97**	**-0.06**	**-0.05%**		**95.24%**
HST		0.13	15.47		0.13	15.47	-0.01	-0.05%		12.38%
Total Electricity Charge on TOU (including HST)			**134.50**			**134.44**	**-0.07**	**-0.05%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.52		-0.08	-9.52	0.00	0.05%		-7.62%
Total Amount on TOU			**124.98**			**124.92**	**-0.06**	**-0.05%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	1,152
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1273
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	26.69%	
Energy Second Tier (kWh)	552	0.090	49.68	552	0.090	49.68	0.00	0.00%	28.70%	
Sub-Total: Energy (RPP)			**95.88**			**95.88**	**0.00**	**0.00%**	**55.39%**	
TOU-Off Peak	749	0.065	48.67	749	0.065	48.67	0.00	0.00%		28.50%
TOU-Mid Peak	196	0.095	18.60	196	0.095	18.60	0.00	0.00%		10.89%
TOU-On Peak	207	0.132	27.37	207	0.132	27.37	0.00	0.00%		16.03%
Sub-Total: Energy (TOU)			**94.65**			**94.65**	0.00	0.00%	**54.68%**	**55.41%**
Service Charge	1	44.12	36.43	1	55.26	36.43	0.00	0.00%	21.05%	21.33%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	1,152	0.0269	0.00	1,152	0.0201	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,152	0.0000	0.01	1,152	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**21.04%**	**21.32%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	121	0.0900	10.89	121	0.0900	10.89	0.00	0.00%	6.29%	6.37%
Line Losses on Cost of Power (based on TOU prices)	121	0.0822	9.94	121	0.0822	9.94	0.00	0.00%	5.74%	5.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**48.10**			**48.10**	**0.00**	**0.00%**	**27.79%**	**28.16%**
Sub-Total: Distribution (based on TOU prices)			**47.15**			**47.15**	**0.00**	**0.00%**	**27.24%**	**27.60%**
Retail Transmission Rate – Network Service Rate	1,273	0.0067	8.58	1,273	0.0068	8.66	0.08	0.89%	5.00%	5.07%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,273	0.0056	7.17	1,273	0.0055	7.00	-0.17	-2.31%	4.04%	4.10%
Sub-Total: Retail Transmission			**15.75**			**15.66**	**-0.09**	**-0.57%**	**9.05%**	**9.17%**
Sub-Total: Delivery (based on two-tier RPP prices)			**63.84**			**63.75**	**-0.09**	**-0.14%**	**36.83%**	**37.33%**
Sub-Total: Delivery (based on TOU prices)			**62.90**			**62.81**	**-0.09**	**-0.14%**	**36.28%**	**36.77%**
Wholesale Market Service Rate	1,273	0.0036	4.58	1,273	0.0036	4.58	0.00	0.00%	2.65%	2.68%
Rural Rate Protection Charge	1,273	0.0003	0.38	1,273	0.0003	0.38	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,273	0.0000	0.00	1,273	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.15%
Sub-Total: Regulatory			**5.21**			**5.21**	**0.00**	**0.00%**	**3.01%**	**3.05%**
Debt Retirement Charge (DRC)	1,152	0.000	**0.00**	1,152	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**164.94**			**164.85**	**-0.09**	**-0.05%**	**95.24%**	
HST		0.13	21.44		0.13	21.43	-0.01	-0.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**186.38**			**186.28**	**-0.10**	**-0.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.20		-0.08	-13.19	0.01	0.05%	-7.62%	
Total Amount on Two-Tier RPP			**173.18**			**173.09**	**-0.09**	**-0.05%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**162.76**			**162.67**	**-0.09**	**-0.05%**		**95.24%**
HST		0.13	21.16		0.13	21.15	-0.01	-0.05%		12.38%
Total Electricity Charge on TOU (including HST)			**183.92**			**183.82**	**-0.10**	**-0.05%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.02		-0.08	-13.01	0.01	0.05%		-7.62%
Total Amount on TOU			**170.90**			**170.80**	**-0.09**	**-0.05%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	2300
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	2542
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	14.69%	
Energy Second Tier (kWh)	1,700	0.090	153.00	1,700	0.090	153.00	0.00	0.00%	48.64%	
Sub-Total: Energy (RPP)			**199.20**			**199.20**	**0.00**	**0.00%**	**63.33%**	
TOU-Off Peak	1,495	0.065	97.18	1,495	0.065	97.18	0.00	0.00%		32.20%
TOU-Mid Peak	391	0.095	37.15	391	0.095	37.15	0.00	0.00%		12.31%
TOU-On Peak	414	0.132	54.65	414	0.132	54.65	0.00	0.00%		18.11%
Sub-Total: Energy (TOU)			**188.97**			**188.97**	0.00	0.00%	**60.07%**	**62.61%**
Service Charge	1	44.12	36.43	1	55.26	36.43	0.00	0.00%	11.58%	12.07%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	2,300	0.0269	0.00	2,300	0.0201	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,300	0.0000	0.02	2,300	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.43**			**36.43**	**0.00**	**0.00%**	**11.58%**	**12.07%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.26%
Line Losses on Cost of Power (based on two-tier RPP prices)	242	0.0900	21.74	242	0.0900	21.74	0.00	0.00%	6.91%	7.20%
Line Losses on Cost of Power (based on TOU prices)	242	0.0822	19.84	242	0.0822	19.84	0.00	0.00%	6.31%	6.57%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.96**			**58.96**	**0.00**	**0.00%**	**18.74%**	**19.53%**
Sub-Total: Distribution (based on TOU prices)			**57.06**			**57.06**	**0.00**	**0.00%**	**18.14%**	**18.91%**
Retail Transmission Rate – Network Service Rate	2,542	0.0067	17.13	2,542	0.0068	17.28	0.15	0.89%	5.49%	5.73%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,542	0.0056	14.31	2,542	0.0055	13.98	-0.33	-2.31%	4.44%	4.63%
Sub-Total: Retail Transmission			**31.44**			**31.26**	**-0.18**	**-0.57%**	**9.94%**	**10.36%**
Sub-Total: Delivery (based on two-tier RPP prices)			**90.40**			**90.22**	**-0.18**	**-0.20%**	**28.68%**	**29.89%**
Sub-Total: Delivery (based on TOU prices)			**88.50**			**88.32**	**-0.18**	**-0.20%**	**28.08%**	**29.26%**
Wholesale Market Service Rate	2,542	0.0036	9.15	2,542	0.0036	9.15	0.00	0.00%	2.91%	3.03%
Rural Rate Protection Charge	2,542	0.0003	0.76	2,542	0.0003	0.76	0.00	0.00%	0.24%	0.25%
Ontario Electricity Support Program Charge	2,542	0.0000	0.00	2,542	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**10.16**			**10.16**	**0.00**	**0.00%**	**3.23%**	**3.37%**
Debt Retirement Charge (DRC)	2,300	0.000	**0.00**	2,300	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**299.76**			**299.58**	**-0.18**	**-0.06%**	**95.24%**	
HST		0.13	38.97		0.13	38.95	-0.02	-0.06%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**338.73**			**338.52**	**-0.20**	**-0.06%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.98		-0.08	-23.97	0.01	0.06%	-7.62%	
Total Amount on Two-Tier RPP			**314.75**			**314.56**	**-0.19**	**-0.06%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**287.63**			**287.45**	**-0.18**	**-0.06%**		**95.24%**
HST		0.13	37.39		0.13	37.37	-0.02	-0.06%		12.38%
Total Electricity Charge on TOU (including HST)			**325.02**			**324.82**	**-0.20**	**-0.06%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.01		-0.08	-23.00	0.01	0.06%		-7.62%
Total Amount on TOU			**302.01**			**301.83**	**-0.19**	**-0.06%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	50
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	55
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	50	0.077	3.85	50	0.077	3.85	0.00	0.00%	5.82%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**3.85**			**3.85**	**0.00**	**0.00%**	**5.82%**	
TOU-Off Peak	33	0.065	2.11	33	0.065	2.11	0.00	0.00%		3.18%
TOU-Mid Peak	9	0.095	0.81	9	0.095	0.81	0.00	0.00%		1.21%
TOU-On Peak	9	0.132	1.19	9	0.132	1.19	0.00	0.00%		1.79%
Sub-Total: Energy (TOU)			**4.11**			**4.11**	0.00	0.00%	**6.21%**	**6.18%**
Service Charge	1	50.05	50.05	1	55.37	55.37	5.32	10.63%	83.65%	83.28%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	50	0.0439	2.20	50	0.0317	1.59	-0.61	-27.79%	2.39%	2.38%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	50	0.0000	0.00	50	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**52.24**			**56.95**	**4.71**	**9.02%**	**86.04%**	**85.66%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.19%	1.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	5	0.0770	0.40	5	0.0770	0.40	0.00	0.00%	0.60%	0.60%
Line Losses on Cost of Power (based on TOU prices)	5	0.0822	0.43	5	0.0822	0.43	0.00	0.00%	0.65%	0.64%
Sub-Total: Distribution (based on two-tier RPP prices)			**53.43**			**58.14**	**4.71**	**8.81%**	**87.84%**	**87.45%**
Sub-Total: Distribution (based on TOU prices)			**53.46**			**58.17**	**4.71**	**8.81%**	**87.88%**	**87.49%**
Retail Transmission Rate – Network Service Rate	55	0.0057	0.31	55	0.0058	0.32	0.01	2.55%	0.48%	0.48%
Retail Transmission Rate – Line and Transformation Connection Service Rate	55	0.0048	0.27	55	0.0047	0.26	-0.01	-2.51%	0.39%	0.39%
Sub-Total: Retail Transmission			**0.58**			**0.58**	**0.00**	**0.22%**	**0.88%**	**0.87%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.01**			**58.72**	**4.71**	**8.72%**	**88.72%**	**88.32%**
Sub-Total: Delivery (based on TOU prices)			**54.04**			**58.75**	**4.71**	**8.72%**	**88.76%**	**88.36%**
Wholesale Market Service Rate	55	0.0036	0.20	55	0.0036	0.20	0.00	0.00%	0.30%	0.30%
Rural Rate Protection Charge	55	0.0003	0.02	55	0.0003	0.02	0.00	0.00%	0.03%	0.02%
Ontario Electricity Support Program Charge	55	0.0000	0.00	55	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.38%	0.38%
Sub-Total: Regulatory			**0.47**			**0.47**	**0.00**	**0.00%**	**0.70%**	**0.70%**
Debt Retirement Charge (DRC)	50	0.000	**0.00**	50	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**58.33**			**63.04**	**4.71**	**8.08%**	**95.24%**	
HST		0.13	7.58		0.13	8.20	0.61	8.08%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**65.91**			**71.23**	**5.32**	**8.08%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.67		-0.08	-5.04	-0.38	-8.08%	-7.62%	
Total Amount on Two-Tier RPP			**61.24**			**66.19**	**4.95**	**8.08%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**58.61**			**63.32**	**4.71**	**8.04%**		**95.24%**
HST		0.13	7.62		0.13	8.23	0.61	8.04%		12.38%
Total Electricity Charge on TOU (including HST)			**66.23**			**71.56**	**5.32**	**8.04%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.69		-0.08	-5.07	-0.38	-8.04%		-7.62%
Total Amount on TOU			**61.54**			**66.49**	**4.95**	**8.04%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	352
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	389
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	352	0.077	27.10	352	0.077	27.10	0.00	0.00%	25.04%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**27.10**			**27.10**	**0.00**	**0.00%**	**25.04%**	
TOU-Off Peak	229	0.065	14.87	229	0.065	14.87	0.00	0.00%		13.48%
TOU-Mid Peak	60	0.095	5.68	60	0.095	5.68	0.00	0.00%		5.15%
TOU-On Peak	63	0.132	8.36	63	0.132	8.36	0.00	0.00%		7.58%
Sub-Total: Energy (TOU)			**28.92**			**28.92**	0.00	0.00%	**26.72%**	**26.21%**
Service Charge	1	50.05	50.05	1	55.37	55.37	5.32	10.63%	51.15%	50.18%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	352	0.0439	15.45	352	0.0317	11.16	-4.29	-27.79%	10.31%	10.11%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	352	0.0000	0.00	352	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**65.50**			**66.53**	**1.03**	**1.57%**	**61.46%**	**60.29%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.73%	0.72%
Line Losses on Cost of Power (based on two-tier RPP prices)	37	0.0770	2.82	37	0.0770	2.82	0.00	0.00%	2.60%	2.55%
Line Losses on Cost of Power (based on TOU prices)	37	0.0822	3.01	37	0.0822	3.01	0.00	0.00%	2.78%	2.73%
Sub-Total: Distribution (based on two-tier RPP prices)			**69.11**			**70.14**	**1.03**	**1.48%**	**64.80%**	**63.56%**
Sub-Total: Distribution (based on TOU prices)			**69.30**			**70.33**	**1.03**	**1.48%**	**64.97%**	**63.73%**
Retail Transmission Rate – Network Service Rate	389	0.0057	2.20	389	0.0058	2.25	0.06	2.55%	2.08%	2.04%
Retail Transmission Rate – Line and Transformation Connection Service Rate	389	0.0048	1.87	389	0.0047	1.83	-0.05	-2.51%	1.69%	1.66%
Sub-Total: Retail Transmission			**4.07**			**4.08**	**0.01**	**0.22%**	**3.77%**	**3.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**73.18**			**74.22**	**1.03**	**1.41%**	**68.57%**	**67.26%**
Sub-Total: Delivery (based on TOU prices)			**73.37**			**74.41**	**1.03**	**1.41%**	**68.74%**	**67.43%**
Wholesale Market Service Rate	389	0.0036	1.40	389	0.0036	1.40	0.00	0.00%	1.29%	1.27%
Rural Rate Protection Charge	389	0.0003	0.12	389	0.0003	0.12	0.00	0.00%	0.11%	0.11%
Ontario Electricity Support Program Charge	389	0.0000	0.00	389	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.23%	0.23%
Sub-Total: Regulatory			**1.77**			**1.77**	**0.00**	**0.00%**	**1.63%**	**1.60%**
Debt Retirement Charge (DRC)	352	0.000	**0.00**	352	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**102.05**			**103.09**	**1.03**	**1.01%**	**95.24%**	
HST		0.13	13.27		0.13	13.40	0.13	1.01%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**115.32**			**116.49**	**1.17**	**1.01%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.16		-0.08	-8.25	-0.08	-1.01%	-7.62%	
Total Amount on Two-Tier RPP			**107.16**			**108.24**	**1.09**	**1.01%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**104.06**			**105.09**	**1.03**	**0.99%**		**95.24%**
HST		0.13	13.53		0.13	13.66	0.13	0.99%		12.38%
Total Electricity Charge on TOU (including HST)			**117.59**			**118.76**	**1.17**	**0.99%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.32		-0.08	-8.41	-0.08	-0.99%		-7.62%
Total Amount on TOU			**109.26**			**110.35**	**1.09**	**0.99%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1104
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	22.50%	
Energy Second Tier (kWh)	400	0.090	36.00	400	0.090	36.00	0.00	0.00%	17.53%	
Sub-Total: Energy (RPP)			**82.20**			**82.20**	**0.00**	**0.00%**	**40.03%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		20.66%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.90%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		11.62%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**40.01%**	**40.18%**
Service Charge	1	50.05	50.05	1	55.37	55.37	5.32	10.63%	26.96%	27.08%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0439	43.90	1,000	0.0317	31.70	-12.20	-27.79%	15.44%	15.50%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.01	1,000	0.0000	0.01	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**93.96**			**87.08**	**-6.88**	**-7.32%**	**42.40%**	**42.59%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.38%	0.39%
Line Losses on Cost of Power (based on two-tier RPP prices)	104	0.0900	9.36	104	0.0900	9.36	0.00	0.00%	4.56%	4.58%
Line Losses on Cost of Power (based on TOU prices)	104	0.0822	8.54	104	0.0822	8.54	0.00	0.00%	4.16%	4.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**104.11**			**97.23**	**-6.88**	**-6.61%**	**47.35%**	**47.55%**
Sub-Total: Distribution (based on TOU prices)			**103.29**			**96.41**	**-6.88**	**-6.66%**	**46.95%**	**47.16%**
Retail Transmission Rate – Network Service Rate	1,104	0.0057	6.24	1,104	0.0058	6.40	0.16	2.55%	3.12%	3.13%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,104	0.0048	5.32	1,104	0.0047	5.19	-0.13	-2.51%	2.53%	2.54%
Sub-Total: Retail Transmission			**11.57**			**11.59**	**0.03**	**0.22%**	**5.64%**	**5.67%**
Sub-Total: Delivery (based on two-tier RPP prices)			**115.67**			**108.82**	**-6.85**	**-5.93%**	**52.99%**	**53.22%**
Sub-Total: Delivery (based on TOU prices)			**114.86**			**108.00**	**-6.85**	**-5.97%**	**52.59%**	**52.83%**
Wholesale Market Service Rate	1,104	0.0036	3.97	1,104	0.0036	3.97	0.00	0.00%	1.94%	1.94%
Rural Rate Protection Charge	1,104	0.0003	0.33	1,104	0.0003	0.33	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	1,104	0.0000	0.00	1,104	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.12%	0.12%
Sub-Total: Regulatory			**4.56**			**4.56**	**0.00**	**0.00%**	**2.22%**	**2.23%**
Debt Retirement Charge (DRC)	1,000	0.000	**0.00**	1,000	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**202.43**			**195.58**	**-6.85**	**-3.39%**	**95.24%**	
HST		0.13	26.32		0.13	25.42	-0.89	-3.39%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**228.75**			**221.00**	**-7.75**	**-3.39%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.19		-0.08	-15.65	0.55	3.39%	-7.62%	
Total Amount on Two-Tier RPP			**212.55**			**205.35**	**-7.20**	**-3.39%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**201.57**			**194.72**	**-6.85**	**-3.40%**		**95.24%**
HST		0.13	26.20		0.13	25.31	-0.89	-3.40%		12.38%
Total Electricity Charge on TOU (including HST)			**227.78**			**220.03**	**-7.75**	**-3.40%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.13		-0.08	-15.58	0.55	3.40%		-7.62%
Total Amount on TOU			**211.65**			**204.46**	**-7.20**	**-3.40%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	Uge
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1067
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	33.12%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.90%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**46.02%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		24.03%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.18%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.51%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**47.12%**	**46.73%**
Service Charge	1	25.1	25.10	1	25.55	25.55	0.45	1.79%	14.65%	14.53%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0299	29.90	1,000	0.0308	30.80	0.90	3.01%	17.66%	17.52%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.0300	1,000	0.0000	0.0300	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**55.04**			**56.39**	**1.35**	**2.45%**	**32.34%**	**32.07%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.45%	0.45%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.03	67	0.0900	6.03	0.00	0.00%	3.46%	3.43%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.50	67	0.0822	5.50	0.00	0.00%	3.16%	3.13%
Sub-Total: Distribution (based on two-tier RPP prices)			**61.86**			**63.21**	**1.35**	**2.18%**	**36.25%**	**35.95%**
Sub-Total: Distribution (based on TOU prices)			**61.33**			**62.68**	**1.35**	**2.20%**	**35.95%**	**35.65%**
Retail Transmission Rate – Network Service Rate	1,067	0.0061	6.52	1,067	0.0058	6.19	-0.33	-5.01%	3.55%	3.52%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,067	0.0047	4.96	1,067	0.0047	5.01	0.05	1.03%	2.88%	2.85%
Sub-Total: Retail Transmission			**11.48**			**11.20**	**-0.28**	**-2.40%**	**6.42%**	**6.37%**
Sub-Total: Delivery (based on two-tier RPP prices)			**73.34**			**74.41**	**1.07**	**1.47%**	**42.67%**	**42.32%**
Sub-Total: Delivery (based on TOU prices)			**72.81**			**73.89**	**1.07**	**1.48%**	**42.37%**	**42.02%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.20%	2.18%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.53%**	**2.51%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.01%**	**3.98%**
Total Electricty Charge on Two-Tier RPP			**165.00**			**166.07**	**1.07**	**0.65%**	**95.24%**	
HST		0.13	21.45		0.13	21.59	0.14	0.65%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**186.45**			**187.66**	**1.21**	**0.65%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.20		-0.08	-13.29	-0.09	-0.65%	-7.62%	
Total Amount on Two-Tier RPP			**173.25**			**174.38**	**1.13**	**0.65%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**166.38**			**167.46**	**1.07**	**0.65%**		**95.24%**
HST		0.13	21.63		0.13	21.77	0.14	0.65%		12.38%
Total Electricity Charge on TOU (including HST)			**188.01**			**189.23**	**1.21**	**0.65%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.31		-0.08	-13.40	-0.09	-0.65%		-7.62%
Total Amount on TOU			**174.70**			**175.83**	**1.13**	**0.65%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	Uge
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2134
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.44%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	33.98%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**51.43%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		26.10%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		9.98%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		14.68%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**49.63%**	**50.76%**
Service Charge	1	25.1	25.10	1	25.55	25.55	0.45	1.79%	7.72%	7.89%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0299	59.80	2,000	0.0308	61.60	1.80	3.01%	18.61%	19.03%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,000	0.0000	0.0600	2,000	0.0000	0.0600	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**84.97**			**87.22**	**2.25**	**2.65%**	**26.34%**	**26.94%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.24%
Line Losses on Cost of Power (based on two-tier RPP prices)	134	0.0900	12.06	134	0.0900	12.06	0.00	0.00%	3.64%	3.73%
Line Losses on Cost of Power (based on TOU prices)	134	0.0822	11.01	134	0.0822	11.01	0.00	0.00%	3.33%	3.40%
Sub-Total: Distribution (based on two-tier RPP prices)			**97.82**			**100.07**	**2.25**	**2.30%**	**30.23%**	**30.91%**
Sub-Total: Distribution (based on TOU prices)			**96.77**			**99.02**	**2.25**	**2.33%**	**29.91%**	**30.59%**
Retail Transmission Rate – Network Service Rate	2,134	0.0061	13.03	2,134	0.0058	12.38	-0.65	-5.01%	3.74%	3.82%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,134	0.0047	9.93	2,134	0.0047	10.03	0.10	1.03%	3.03%	3.10%
Sub-Total: Retail Transmission			**22.96**			**22.41**	**-0.55**	**-2.40%**	**6.77%**	**6.92%**
Sub-Total: Delivery (based on two-tier RPP prices)			**120.78**			**122.48**	**1.70**	**1.41%**	**36.99%**	**37.83%**
Sub-Total: Delivery (based on TOU prices)			**119.73**			**121.42**	**1.70**	**1.42%**	**36.68%**	**37.51%**
Wholesale Market Service Rate	2,134	0.0036	7.68	2,134	0.0036	7.68	0.00	0.00%	2.32%	2.37%
Rural Rate Protection Charge	2,134	0.0003	0.64	2,134	0.0003	0.64	0.00	0.00%	0.19%	0.20%
Ontario Electricity Support Program Charge	2,134	0.0000	0.00	2,134	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.59%**	**2.65%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.23%**	**4.32%**
Total Electricty Charge on Two-Tier RPP			**313.60**			**315.30**	**1.70**	**0.54%**	**95.24%**	
HST		0.13	40.77		0.13	40.99	0.22	0.54%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**354.37**			**356.29**	**1.92**	**0.54%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-25.09		-0.08	-25.22	-0.14	-0.54%	-7.62%	
Total Amount on Two-Tier RPP			**329.28**			**331.06**	**1.78**	**0.54%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**306.62**			**308.32**	**1.70**	**0.55%**		**95.24%**
HST		0.13	39.86		0.13	40.08	0.22	0.55%		12.38%
Total Electricity Charge on TOU (including HST)			**346.48**			**348.40**	**1.92**	**0.55%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.53		-0.08	-24.67	-0.14	-0.55%		-7.62%
Total Amount on TOU			**321.95**			**323.73**	**1.78**	**0.55%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Uge
Monthly Consumption (kWh)	2,759
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2943.853
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.83%	
Energy Second Tier (kWh)	2,009	0.090	180.81	2,009	0.090	180.81	0.00	0.00%	40.18%	
Sub-Total: Energy (RPP)			**238.56**			**238.56**	**0.00**	**0.00%**	**53.01%**	
TOU-Off Peak	1,793	0.065	116.57	1,793	0.065	116.57	0.00	0.00%		26.74%
TOU-Mid Peak	469	0.095	44.56	469	0.095	44.56	0.00	0.00%		10.22%
TOU-On Peak	497	0.132	65.55	497	0.132	65.55	0.00	0.00%		15.04%
Sub-Total: Energy (TOU)			**226.68**			**226.68**	0.00	0.00%	**50.37%**	**51.99%**
Service Charge	1	25.1	25.10	1	25.55	25.55	0.45	1.79%	5.68%	5.86%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,759	0.0299	82.49	2,759	0.0308	84.98	2.48	3.01%	18.88%	19.49%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,759	0.0000	0.0828	2,759	0.0000	0.0828	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**107.68**			**110.62**	**2.93**	**2.72%**	**24.58%**	**25.37%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.18%	0.18%
Line Losses on Cost of Power (based on two-tier RPP prices)	185	0.0900	16.64	185	0.0900	16.64	0.00	0.00%	3.70%	3.82%
Line Losses on Cost of Power (based on TOU prices)	185	0.0822	15.19	185	0.0822	15.19	0.00	0.00%	3.38%	3.48%
Sub-Total: Distribution (based on two-tier RPP prices)			**125.11**			**128.04**	**2.93**	**2.34%**	**28.46%**	**29.37%**
Sub-Total: Distribution (based on TOU prices)			**123.66**			**126.60**	**2.93**	**2.37%**	**28.13%**	**29.04%**
Retail Transmission Rate – Network Service Rate	2,944	0.0061	17.98	2,944	0.0058	17.07	-0.90	-5.01%	3.79%	3.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,944	0.0047	13.69	2,944	0.0047	13.84	0.14	1.03%	3.07%	3.17%
Sub-Total: Retail Transmission			**31.67**			**30.91**	**-0.76**	**-2.40%**	**6.87%**	**7.09%**
Sub-Total: Delivery (based on two-tier RPP prices)			**156.78**			**158.96**	**2.17**	**1.39%**	**35.32%**	**36.46%**
Sub-Total: Delivery (based on TOU prices)			**155.33**			**157.51**	**2.17**	**1.40%**	**35.00%**	**36.13%**
Wholesale Market Service Rate	2,944	0.0036	10.60	2,944	0.0036	10.60	0.00	0.00%	2.36%	2.43%
Rural Rate Protection Charge	2,944	0.0003	0.88	2,944	0.0003	0.88	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,944	0.0000	0.00	2,944	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.73**			**11.73**	**0.00**	**0.00%**	**2.61%**	**2.69%**
Debt Retirement Charge (DRC)	2,759	0.007	**19.31**	2,759	0.007	**19.31**	**0.00**	**0.00%**	**4.29%**	**4.43%**
Total Electricty Charge on Two-Tier RPP			**426.39**			**428.56**	**2.17**	**0.51%**	**95.24%**	
HST		0.13	55.43		0.13	55.71	0.28	0.51%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**481.82**			**484.27**	**2.46**	**0.51%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-34.11		-0.08	-34.28	-0.17	-0.51%	-7.62%	
Total Amount on Two-Tier RPP			**447.70**			**449.99**	**2.28**	**0.51%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**413.06**			**415.23**	**2.17**	**0.53%**		**95.24%**
HST		0.13	53.70		0.13	53.98	0.28	0.53%		12.38%
Total Electricity Charge on TOU (including HST)			**466.75**			**469.21**	**2.46**	**0.53%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.04		-0.08	-33.22	-0.17	-0.53%		-7.62%
Total Amount on TOU			**433.71**			**435.99**	**2.28**	**0.53%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	Uge
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16005
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.44%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	54.16%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**56.60%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		28.21%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		10.78%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		15.86%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**52.04%**	**54.86%**
Service Charge	1	25.1	25.10	1	25.55	25.55	0.45	1.79%	1.08%	1.14%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0299	448.50	15,000	0.0308	462.00	13.50	3.01%	19.51%	20.57%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	15,000	0.0000	0.4500	15,000	0.0000	0.4500	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**474.06**			**488.01**	**13.95**	**2.94%**	**20.61%**	**21.72%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,005	0.0900	90.45	1,005	0.0900	90.45	0.00	0.00%	3.82%	4.03%
Line Losses on Cost of Power (based on TOU prices)	1,005	0.0822	82.57	1,005	0.0822	82.57	0.00	0.00%	3.49%	3.68%
Sub-Total: Distribution (based on two-tier RPP prices)			**565.30**			**579.25**	**13.95**	**2.47%**	**24.46%**	**25.78%**
Sub-Total: Distribution (based on TOU prices)			**557.42**			**571.37**	**13.95**	**2.50%**	**24.13%**	**25.43%**
Retail Transmission Rate – Network Service Rate	16,005	0.0061	97.73	16,005	0.0058	92.83	-4.90	-5.01%	3.92%	4.13%
Retail Transmission Rate – Line and Transformation Connection Service Rate	16,005	0.0047	74.46	16,005	0.0047	75.22	0.77	1.03%	3.18%	3.35%
Sub-Total: Retail Transmission			**172.18**			**168.05**	**-4.13**	**-2.40%**	**7.10%**	**7.48%**
Sub-Total: Delivery (based on two-tier RPP prices)			**737.48**			**747.30**	**9.82**	**1.33%**	**31.56%**	**33.27%**
Sub-Total: Delivery (based on TOU prices)			**729.60**			**739.42**	**9.82**	**1.35%**	**31.23%**	**32.91%**
Wholesale Market Service Rate	16,005	0.0036	57.62	16,005	0.0036	57.62	0.00	0.00%	2.43%	2.56%
Rural Rate Protection Charge	16,005	0.0003	4.80	16,005	0.0003	4.80	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	16,005	0.0000	0.00	16,005	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.67**			**62.67**	**0.00**	**0.00%**	**2.65%**	**2.79%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.43%**	**4.67%**
Total Electricty Charge on Two-Tier RPP			**2,245.40**			**2,255.22**	**9.82**	**0.44%**	**95.24%**	
HST		0.13	291.90		0.13	293.18	1.28	0.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,537.30**			**2,548.40**	**11.10**	**0.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-179.63		-0.08	-180.42	-0.79	-0.44%	-7.62%	
Total Amount on Two-Tier RPP			**2,357.67**			**2,367.98**	**10.31**	**0.44%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**2,129.67**			**2,139.49**	**9.82**	**0.46%**		**95.24%**
HST		0.13	276.86		0.13	278.13	1.28	0.46%		12.38%
Total Electricity Charge on TOU (including HST)			**2,406.53**			**2,417.62**	**11.10**	**0.46%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-170.37		-0.08	-171.16	-0.79	-0.46%		-7.62%
Total Amount on TOU			**2,236.15**			**2,246.47**	**10.31**	**0.46%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	Gse
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1096
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	26.35%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	10.26%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**36.61%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		19.17%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.33%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		10.78%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**37.48%**	**37.27%**
Service Charge	1	30.88	30.88	1	31.38	31.38	0.50	1.62%	14.32%	14.24%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0633	63.30	1,000	0.0652	65.20	1.90	3.00%	29.74%	29.58%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.0200	1,000	0.0000	0.0200	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**94.20**			**96.60**	**2.40**	**2.55%**	**44.07%**	**43.83%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.36%	0.36%
Line Losses on Cost of Power (based on two-tier RPP prices)	96	0.0900	8.64	96	0.0900	8.64	0.00	0.00%	3.94%	3.92%
Line Losses on Cost of Power (based on TOU prices)	96	0.0822	7.89	96	0.0822	7.89	0.00	0.00%	3.60%	3.58%
Sub-Total: Distribution (based on two-tier RPP prices)			**103.63**			**106.03**	**2.40**	**2.32%**	**48.37%**	**48.10%**
Sub-Total: Distribution (based on TOU prices)			**102.88**			**105.28**	**2.40**	**2.33%**	**48.03%**	**47.76%**
Retail Transmission Rate – Network Service Rate	1,096	0.0057	6.24	1,096	0.0055	6.03	-0.21	-3.39%	2.75%	2.73%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,096	0.0045	4.90	1,096	0.0045	4.93	0.03	0.58%	2.25%	2.24%
Sub-Total: Retail Transmission			**11.14**			**10.96**	**-0.18**	**-1.64%**	**5.00%**	**4.97%**
Sub-Total: Delivery (based on two-tier RPP prices)			**114.78**			**116.99**	**2.22**	**1.93%**	**53.37%**	**53.08%**
Sub-Total: Delivery (based on TOU prices)			**114.02**			**116.24**	**2.22**	**1.94%**	**53.03%**	**52.74%**
Wholesale Market Service Rate	1,096	0.0036	3.95	1,096	0.0036	3.95	0.00	0.00%	1.80%	1.79%
Rural Rate Protection Charge	1,096	0.0003	0.33	1,096	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,096	0.0000	0.00	1,096	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.11%	0.11%
Sub-Total: Regulatory			**4.52**			**4.52**	**0.00**	**0.00%**	**2.06%**	**2.05%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.19%**	**3.18%**
Total Electricty Charge on Two-Tier RPP			**206.55**			**208.77**	**2.22**	**1.07%**	**95.24%**	
HST		0.13	26.85		0.13	27.14	0.29	1.07%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**233.40**			**235.91**	**2.51**	**1.07%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.52		-0.08	-16.70	-0.18	-1.07%	-7.62%	
Total Amount on Two-Tier RPP			**216.88**			**219.20**	**2.33**	**1.07%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**207.71**			**209.92**	**2.22**	**1.07%**		**95.24%**
HST		0.13	27.00		0.13	27.29	0.29	1.07%		12.38%
Total Electricity Charge on TOU (including HST)			**234.71**			**237.21**	**2.51**	**1.07%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.62		-0.08	-16.79	-0.18	-1.07%		-7.62%
Total Amount on TOU			**218.09**			**220.42**	**2.33**	**1.07%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	Gse
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2192
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	13.93%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	27.13%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**41.06%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		20.77%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		7.94%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		11.68%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**39.63%**	**40.39%**
Service Charge	1	30.88	30.88	1	31.38	31.38	0.50	1.62%	7.57%	7.71%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0633	126.60	2,000	0.0652	130.40	3.80	3.00%	31.45%	32.06%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,000	0.0000	0.0400	2,000	0.0000	0.0400	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**157.52**			**161.82**	**4.30**	**2.73%**	**39.03%**	**39.78%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	192	0.0900	17.28	192	0.0900	17.28	0.00	0.00%	4.17%	4.25%
Line Losses on Cost of Power (based on TOU prices)	192	0.0822	15.77	192	0.0822	15.77	0.00	0.00%	3.80%	3.88%
Sub-Total: Distribution (based on two-tier RPP prices)			**175.59**			**179.89**	**4.30**	**2.45%**	**43.39%**	**44.22%**
Sub-Total: Distribution (based on TOU prices)			**174.09**			**178.39**	**4.30**	**2.47%**	**43.03%**	**43.85%**
Retail Transmission Rate – Network Service Rate	2,192	0.0057	12.48	2,192	0.0055	12.06	-0.42	-3.39%	2.91%	2.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,192	0.0045	9.81	2,192	0.0045	9.86	0.06	0.58%	2.38%	2.42%
Sub-Total: Retail Transmission			**22.29**			**21.92**	**-0.37**	**-1.64%**	**5.29%**	**5.39%**
Sub-Total: Delivery (based on two-tier RPP prices)			**197.88**			**201.81**	**3.93**	**1.99%**	**48.68%**	**49.61%**
Sub-Total: Delivery (based on TOU prices)			**196.37**			**200.31**	**3.93**	**2.00%**	**48.31%**	**49.24%**
Wholesale Market Service Rate	2,192	0.0036	7.89	2,192	0.0036	7.89	0.00	0.00%	1.90%	1.94%
Rural Rate Protection Charge	2,192	0.0003	0.66	2,192	0.0003	0.66	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,192	0.0000	0.00	2,192	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.80**			**8.80**	**0.00**	**0.00%**	**2.12%**	**2.16%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.38%**	**3.44%**
Total Electricty Charge on Two-Tier RPP			**390.93**			**394.86**	**3.93**	**1.01%**	**95.24%**	
HST		0.13	50.82		0.13	51.33	0.51	1.01%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**441.75**			**446.19**	**4.45**	**1.01%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-31.27		-0.08	-31.59	-0.31	-1.01%	-7.62%	
Total Amount on Two-Tier RPP			**410.47**			**414.60**	**4.13**	**1.01%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**383.49**			**387.43**	**3.93**	**1.03%**		**95.24%**
HST		0.13	49.85		0.13	50.37	0.51	1.03%		12.38%
Total Electricity Charge on TOU (including HST)			**433.35**			**437.79**	**4.45**	**1.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.68		-0.08	-30.99	-0.31	-1.03%		-7.62%
Total Amount on TOU			**402.67**			**406.80**	**4.13**	**1.03%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Gse
Monthly Consumption (kWh)	1,982
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2172.272
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.05%	
Energy Second Tier (kWh)	1,232	0.090	110.88	1,232	0.090	110.88	0.00	0.00%	26.97%	
Sub-Total: Energy (RPP)			**168.63**			**168.63**	**0.00**	**0.00%**	**41.02%**	
TOU-Off Peak	1,288	0.065	83.74	1,288	0.065	83.74	0.00	0.00%		20.76%
TOU-Mid Peak	337	0.095	32.01	337	0.095	32.01	0.00	0.00%		7.93%
TOU-On Peak	357	0.132	47.09	357	0.132	47.09	0.00	0.00%		11.67%
Sub-Total: Energy (TOU)			**162.84**			**162.84**	0.00	0.00%	**39.61%**	**40.36%**
Service Charge	1	30.88	30.88	1	31.38	31.38	0.50	1.62%	7.63%	7.78%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,982	0.0633	125.46	1,982	0.0652	129.23	3.77	3.00%	31.44%	32.03%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,982	0.0000	0.0396	1,982	0.0000	0.0396	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**156.38**			**160.65**	**4.27**	**2.73%**	**39.08%**	**39.82%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	190	0.0900	17.12	190	0.0900	17.12	0.00	0.00%	4.17%	4.24%
Line Losses on Cost of Power (based on TOU prices)	190	0.0822	15.63	190	0.0822	15.63	0.00	0.00%	3.80%	3.87%
Sub-Total: Distribution (based on two-tier RPP prices)			**174.30**			**178.56**	**4.27**	**2.45%**	**43.44%**	**44.26%**
Sub-Total: Distribution (based on TOU prices)			**172.80**			**177.07**	**4.27**	**2.47%**	**43.07%**	**43.89%**
Retail Transmission Rate – Network Service Rate	2,172	0.0057	12.37	2,172	0.0055	11.95	-0.42	-3.39%	2.91%	2.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,172	0.0045	9.72	2,172	0.0045	9.78	0.06	0.58%	2.38%	2.42%
Sub-Total: Retail Transmission			**22.09**			**21.72**	**-0.36**	**-1.64%**	**5.28%**	**5.38%**
Sub-Total: Delivery (based on two-tier RPP prices)			**196.38**			**200.29**	**3.90**	**1.99%**	**48.72%**	**49.64%**
Sub-Total: Delivery (based on TOU prices)			**194.89**			**198.79**	**3.90**	**2.00%**	**48.36%**	**49.27%**
Wholesale Market Service Rate	2,172	0.0036	7.82	2,172	0.0036	7.82	0.00	0.00%	1.90%	1.94%
Rural Rate Protection Charge	2,172	0.0003	0.65	2,172	0.0003	0.65	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,172	0.0000	0.00	2,172	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.72**			**8.72**	**0.00**	**0.00%**	**2.12%**	**2.16%**
Debt Retirement Charge (DRC)	1,982	0.007	**13.87**	1,982	0.007	**13.87**	**0.00**	**0.00%**	**3.37%**	**3.44%**
Total Electricty Charge on Two-Tier RPP			**387.61**			**391.51**	**3.90**	**1.01%**	**95.24%**	
HST		0.13	50.39		0.13	50.90	0.51	1.01%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**438.00**			**442.41**	**4.41**	**1.01%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-31.01		-0.08	-31.32	-0.31	-1.01%	-7.62%	
Total Amount on Two-Tier RPP			**406.99**			**411.09**	**4.10**	**1.01%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**380.33**			**384.23**	**3.90**	**1.03%**		**95.24%**
HST		0.13	49.44		0.13	49.95	0.51	1.03%		12.38%
Total Electricity Charge on TOU (including HST)			**429.77**			**434.18**	**4.41**	**1.03%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.43		-0.08	-30.74	-0.31	-1.03%		-7.62%
Total Amount on TOU			**399.34**			**403.44**	**4.10**	**1.03%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	Gse
Monthly Consumption (kWh)	15,000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16440
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	1.95%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	43.40%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**45.36%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		22.40%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		8.56%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		12.59%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**41.71%**	**43.55%**
Service Charge	1	30.88	30.88	1	31.38	31.38	0.50	1.62%	1.06%	1.11%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0633	949.50	15,000	0.0652	978.00	28.50	3.00%	33.10%	34.56%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	15,000	0.0000	0.3000	15,000	0.0000	0.3000	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**980.68**			**1,009.68**	**29.00**	**2.96%**	**34.17%**	**35.68%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,440	0.0900	129.60	1,440	0.0900	129.60	0.00	0.00%	4.39%	4.58%
Line Losses on Cost of Power (based on TOU prices)	1,440	0.0822	118.31	1,440	0.0822	118.31	0.00	0.00%	4.00%	4.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**1,111.07**			**1,140.07**	**29.00**	**2.61%**	**38.58%**	**40.29%**
Sub-Total: Distribution (based on TOU prices)			**1,099.78**			**1,128.78**	**29.00**	**2.64%**	**38.20%**	**39.89%**
Retail Transmission Rate – Network Service Rate	16,440	0.0057	93.59	16,440	0.0055	90.42	-3.17	-3.39%	3.06%	3.20%
Retail Transmission Rate – Line and Transformation Connection Service Rate	16,440	0.0045	73.55	16,440	0.0045	73.98	0.43	0.58%	2.50%	2.61%
Sub-Total: Retail Transmission			**167.15**			**164.40**	**-2.75**	**-1.64%**	**5.56%**	**5.81%**
Sub-Total: Delivery (based on two-tier RPP prices)			**1,278.22**			**1,304.47**	**26.25**	**2.05%**	**44.15%**	**46.10%**
Sub-Total: Delivery (based on TOU prices)			**1,266.93**			**1,293.18**	**26.25**	**2.07%**	**43.77%**	**45.70%**
Wholesale Market Service Rate	16,440	0.0036	59.18	16,440	0.0036	59.18	0.00	0.00%	2.00%	2.09%
Rural Rate Protection Charge	16,440	0.0003	4.93	16,440	0.0003	4.93	0.00	0.00%	0.17%	0.17%
Ontario Electricity Support Program Charge	16,440	0.0000	0.00	16,440	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**64.37**			**64.37**	**0.00**	**0.00%**	**2.18%**	**2.27%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.55%**	**3.71%**
Total Electricty Charge on Two-Tier RPP			**2,787.83**			**2,814.09**	**26.25**	**0.94%**	**95.24%**	
HST		0.13	362.42		0.13	365.83	3.41	0.94%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**3,150.25**			**3,179.92**	**29.67**	**0.94%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-223.03		-0.08	-225.13	-2.10	-0.94%	-7.62%	
Total Amount on Two-Tier RPP			**2,927.23**			**2,954.79**	**27.57**	**0.94%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,668.69**			**2,694.95**	**26.25**	**0.98%**		**95.24%**
HST		0.13	346.93		0.13	350.34	3.41	0.98%		12.38%
Total Electricity Charge on TOU (including HST)			**3,015.62**			**3,045.29**	**29.67**	**0.98%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-213.50		-0.08	-215.60	-2.10	-0.98%		-7.62%
Total Amount on TOU			**2,802.13**			**2,829.70**	**27.57**	**0.98%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.050
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,750	0.077	1,212.75	15,750	0.077	1,212.75	0.00	0.00%	45.59%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,212.75**			**1,212.75**	**0.00**	**0.00%**	**45.59%**
Service Charge	1	105.02	105.02	1	106.68	106.68	1.66	1.58%	4.01%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	10.2932	617.59	60	10.5937	635.62	18.03	2.92%	23.89%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0112	0.67	60	0.0112	0.67	0.00	0.00%	0.03%
Volumetric Global Adjustment Account Rider	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**723.30**			**742.99**	**19.69**	**2.72%**	**27.93%**
Retail Transmission Rate – Network Service Rate	60	2.2310	133.86	60	2.1349	128.09	-5.77	-4.31%	4.82%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.7047	102.28	60	1.7285	103.71	1.43	1.40%	3.90%
Sub-Total: Retail Transmission			**236.14**			**231.80**	**-4.34**	**-1.84%**	**8.71%**
Sub-Total: Delivery			**959.44**			**974.79**	**15.35**	**1.60%**	**36.64%**
Wholesale Market Service Rate	15,750	0.0036	56.70	15,750	0.0036	56.70	0.00	0.00%	2.13%
Rural Rate Protection Charge	15,750	0.0003	4.73	15,750	0.0003	4.73	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.68**			**61.68**	**0.00**	**0.00%**	**2.32%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.95%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,338.87**			**2,354.22**	**15.35**	**0.66%**	**88.50%**
HST		0.13	304.05		0.13	306.05	2.00	0.66%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,642.92**			**2,660.27**	**17.35**	**0.66%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,642.92**			**2,660.27**	**17.35**	**0.66%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	50,525
Peak (kW)	138
Loss factor	1.050
Load factor	50%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	53,051
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	53,051	0.077	4,084.95	53,051	0.077	4,084.95	0.00	0.00%	53.56%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,084.95**			**4,084.95**	**0.00**	**0.00%**	**53.56%**
Service Charge	1	105.02	105.02	1	106.68	106.68	1.66	1.58%	1.40%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	138	10.2932	1,420.46	138	10.5937	1,461.93	41.47	2.92%	19.17%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	138	0.0112	1.54	138	0.0112	1.54	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,527.04**			**1,570.17**	**43.13**	**2.82%**	**20.59%**
Retail Transmission Rate – Network Service Rate	138	2.2310	307.88	138	2.1349	294.62	-13.27	-4.31%	3.86%
Retail Transmission Rate – Line and Transformation Connection Service Rate	138	1.7047	235.25	138	1.7285	238.53	3.29	1.40%	3.13%
Sub-Total: Retail Transmission			**543.13**			**533.15**	**-9.98**	**-1.84%**	**6.99%**
Sub-Total: Delivery			**2,070.17**			**2,103.32**	**33.15**	**1.60%**	**27.58%**
Wholesale Market Service Rate	53,051	0.0036	190.98	53,051	0.0036	190.98	0.00	0.00%	2.50%
Rural Rate Protection Charge	53,051	0.0003	15.92	53,051	0.0003	15.92	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**207.15**			**207.15**	**0.00**	**0.00%**	**2.72%**
Debt Retirement Charge (DRC)	50,525	0.007	**353.68**	50,525	0.007	**353.68**	**0.00**	**0.00%**	**4.64%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,715.94**			**6,749.09**	**33.15**	**0.49%**	**88.50%**
HST		0.13	873.07		0.13	877.38	4.31	0.49%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,589.01**			**7,626.47**	**37.46**	**0.49%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,589.01**			**7,626.47**	**37.46**	**0.49%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.050
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	183,750	0.077	14,148.75	183,750	0.077	14,148.75	0.00	0.00%	53.44%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,148.75**			**14,148.75**	**0.00**	**0.00%**	**53.44%**
Service Charge	1	105.02	105.02	1	106.68	106.68	1.66	1.58%	0.40%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	10.2932	5,146.60	500	10.5937	5,296.85	150.25	2.92%	20.01%
Volumetric Global Adjustment Account Rider	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0112	5.59	500	0.0112	5.59	0.00	0.00%	0.02%
Sub-Total: Distribution			**5,257.23**			**5,409.14**	**151.91**	**2.89%**	**20.43%**
Retail Transmission Rate – Network Service Rate	500	2.2310	1,115.52	500	2.1349	1,067.45	-48.07	-4.31%	4.03%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.7047	852.34	500	1.7285	864.25	11.91	1.40%	3.26%
Sub-Total: Retail Transmission			**1,967.86**			**1,931.70**	**-36.16**	**-1.84%**	**7.30%**
Sub-Total: Delivery			**7,225.09**			**7,340.84**	**115.75**	**1.60%**	**27.72%**
Wholesale Market Service Rate	183,750	0.0036	661.50	183,750	0.0036	661.50	0.00	0.00%	2.50%
Rural Rate Protection Charge	183,750	0.0003	55.13	183,750	0.0003	55.13	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**716.88**			**716.88**	**0.00**	**0.00%**	**2.71%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.63%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,315.71**			**23,431.46**	**115.75**	**0.50%**	**88.50%**
HST		0.13	3,031.04		0.13	3,046.09	15.05	0.50%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,346.75**			**26,477.55**	**130.80**	**0.50%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,346.75**			**26,477.55**	**130.80**	**0.50%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.061
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,915
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,915	0.077	1,225.46	15,915	0.077	1,225.46	0.00	0.00%	39.01%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,225.46**			**1,225.46**	**0.00**	**0.00%**	**39.01%**
Service Charge	1	106.19	106.19	1	107.59	107.59	1.40	1.32%	3.42%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	17.9321	1,075.93	60	18.4402	1,106.41	30.49	2.83%	35.22%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0052	0.31	60	0.0052	0.31	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,182.42**			**1,214.30**	**31.89**	**2.70%**	**38.65%**
Retail Transmission Rate – Network Service Rate	60	1.6718	100.31	60	1.5908	95.45	-4.86	-4.85%	3.04%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.2769	76.61	60	1.2918	77.51	0.89	1.17%	2.47%
Sub-Total: Retail Transmission			**176.92**			**172.96**	**-3.97**	**-2.24%**	**5.51%**
Sub-Total: Delivery			**1,359.34**			**1,387.26**	**27.92**	**2.05%**	**44.16%**
Wholesale Market Service Rate	15,915	0.0036	57.29	15,915	0.0036	57.29	0.00	0.00%	1.82%
Rural Rate Protection Charge	15,915	0.0003	4.77	15,915	0.0003	4.77	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.32**			**62.32**	**0.00**	**0.00%**	**1.98%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.34%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,752.11**			**2,780.03**	**27.92**	**1.01%**	**88.50%**
HST		0.13	357.77		0.13	361.40	3.63	1.01%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**3,109.89**			**3,141.44**	**31.55**	**1.01%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**3,109.89**			**3,141.44**	**31.55**	**1.01%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	36,104
Peak (kW)	128
Loss factor	1.061
Load factor	39%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	38,306
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	38,306	0.077	2,949.59	38,306	0.077	2,949.59	0.00	0.00%	42.17%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**2,949.59**			**2,949.59**	**0.00**	**0.00%**	**42.17%**
Service Charge	1	106.19	106.19	1	107.59	107.59	1.40	1.32%	1.54%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	128	17.9321	2,295.31	128	18.4402	2,360.35	65.04	2.83%	33.75%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	128	0.0052	0.66	128	0.0052	0.66	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,402.15**			**2,468.59**	**66.44**	**2.77%**	**35.29%**
Retail Transmission Rate – Network Service Rate	128	1.6718	213.99	128	1.5908	203.62	-10.37	-4.85%	2.91%
Retail Transmission Rate – Line and Transformation Connection Service Rate	128	1.2769	163.44	128	1.2918	165.35	1.91	1.17%	2.36%
Sub-Total: Retail Transmission			**377.44**			**368.97**	**-8.46**	**-2.24%**	**5.28%**
Sub-Total: Delivery			**2,779.59**			**2,837.56**	**57.97**	**2.09%**	**40.57%**
Wholesale Market Service Rate	38,306	0.0036	137.90	38,306	0.0036	137.90	0.00	0.00%	1.97%
Rural Rate Protection Charge	38,306	0.0003	11.49	38,306	0.0003	11.49	0.00	0.00%	0.16%
Ontario Electricity Support Program Charge	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**149.64**			**149.64**	**0.00**	**0.00%**	**2.14%**
Debt Retirement Charge (DRC)	36,104	0.007	**252.73**	36,104	0.007	**252.73**	**0.00**	**0.00%**	**3.61%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,131.55**			**6,189.52**	**57.97**	**0.95%**	**88.50%**
HST		0.13	797.10		0.13	804.64	7.54	0.95%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**6,928.65**			**6,994.16**	**65.51**	**0.95%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**6,928.65**			**6,994.16**	**65.51**	**0.95%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.061
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	185,675
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	185,675	0.077	14,296.98	185,675	0.077	14,296.98	0.00	0.00%	46.83%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,296.98**			**14,296.98**	**0.00**	**0.00%**	**46.83%**
Service Charge	1	106.19	106.19	1	107.59	107.59	1.40	1.32%	0.35%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	17.9321	8,966.05	500	18.4402	9,220.10	254.05	2.83%	30.20%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0052	2.58	500	0.0052	2.58	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**9,074.81**			**9,330.26**	**255.45**	**2.81%**	**30.56%**
Retail Transmission Rate – Network Service Rate	500	1.6718	835.91	500	1.5908	795.40	-40.51	-4.85%	2.61%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.2769	638.46	500	1.2918	645.90	7.44	1.17%	2.12%
Sub-Total: Retail Transmission			**1,474.37**			**1,441.30**	**-33.07**	**-2.24%**	**4.72%**
Sub-Total: Delivery			**10,549.18**			**10,771.56**	**222.38**	**2.11%**	**35.28%**
Wholesale Market Service Rate	185,675	0.0036	668.43	185,675	0.0036	668.43	0.00	0.00%	2.19%
Rural Rate Protection Charge	185,675	0.0003	55.70	185,675	0.0003	55.70	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**724.38**			**724.38**	**0.00**	**0.00%**	**2.37%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.01%**
Total Electricity Charge on Two-Tier RPP (before HST)			**26,795.53**			**27,017.92**	**222.38**	**0.83%**	**88.50%**
HST		0.13	3,483.42		0.13	3,512.33	28.91	0.83%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**30,278.95**			**30,530.25**	**251.29**	**0.83%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**30,278.95**			**30,530.25**	**251.29**	**0.83%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	Dgen
Monthly Consumption (kWh)	300
Peak (kW)	10
Loss factor	1.061
Load factor	4%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	318
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	318	0.077	24.51	318	0.077	24.51	0.00	0.00%	6.19%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**24.51**			**24.51**	**0.00**	**0.00%**	**6.19%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	49.55%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	10	10.6446	106.45	10	11.4098	114.10	7.65	7.19%	28.82%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10	0.0028	0.03	10	0.0028	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**302.65**			**310.30**	**7.65**	**2.53%**	**78.38%**
Retail Transmission Rate – Network Service Rate	10	0.6311	6.31	10	0.6395	6.40	0.08	1.33%	1.62%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	0.5475	5.47	10	0.5543	5.54	0.07	1.25%	1.40%
Sub-Total: Retail Transmission			**11.79**			**11.94**	**0.15**	**1.29%**	**3.02%**
Sub-Total: Delivery			**314.43**			**322.24**	**7.80**	**2.48%**	**81.40%**
Wholesale Market Service Rate	318	0.0036	1.15	318	0.0036	1.15	0.00	0.00%	0.29%
Rural Rate Protection Charge	318	0.0003	0.10	318	0.0003	0.10	0.00	0.00%	0.02%
Ontario Electricity Support Program Charge	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%
Sub-Total: Regulatory			**1.49**			**1.49**	**0.00**	**0.00%**	**0.38%**
Debt Retirement Charge (DRC)	300	0.007	**2.10**	300	0.007	**2.10**	**0.00**	**0.00%**	**0.53%**
Total Electricity Charge on Two-Tier RPP (before HST)			**342.53**			**350.34**	**7.80**	**2.28%**	**88.50%**
HST		0.13	44.53		0.13	45.54	1.01	2.28%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**387.06**			**395.88**	**8.82**	**2.28%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**387.06**			**395.88**	**8.82**	**2.28%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Dgen
Monthly Consumption (kWh)	1,328
Peak (kW)	12
Loss factor	1.061
Load factor	15%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,409
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,409	0.077	108.49	1,409	0.077	108.49	0.00	0.00%	20.39%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**108.49**			**108.49**	**0.00**	**0.00%**	**20.39%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	36.86%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	12	10.6446	127.74	12	11.4098	136.92	9.18	7.19%	25.73%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	12	0.0028	0.03	12	0.0028	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**323.94**			**333.12**	**9.18**	**2.83%**	**62.59%**
Retail Transmission Rate – Network Service Rate	12	0.6311	7.57	12	0.6395	7.67	0.10	1.33%	1.44%
Retail Transmission Rate – Line and Transformation Connection Service Rate	12	0.5475	6.57	12	0.5543	6.65	0.08	1.25%	1.25%
Sub-Total: Retail Transmission			**14.14**			**14.33**	**0.18**	**1.29%**	**2.69%**
Sub-Total: Delivery			**338.08**			**347.45**	**9.37**	**2.77%**	**65.28%**
Wholesale Market Service Rate	1,409	0.0036	5.07	1,409	0.0036	5.07	0.00	0.00%	0.95%
Rural Rate Protection Charge	1,409	0.0003	0.42	1,409	0.0003	0.42	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**5.75**			**5.75**	**0.00**	**0.00%**	**1.08%**
Debt Retirement Charge (DRC)	1,328	0.007	**9.30**	1,328	0.007	**9.30**	**0.00**	**0.00%**	**1.75%**
Total Electricity Charge on Two-Tier RPP (before HST)			**461.62**			**470.98**	**9.37**	**2.03%**	**88.50%**
HST		0.13	60.01		0.13	61.23	1.22	2.03%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**521.63**			**532.21**	**10.58**	**2.03%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**521.63**			**532.21**	**10.58**	**2.03%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	Dgen
Monthly Consumption (kWh)	5,000
Peak (kW)	100
Loss factor	1.061
Load factor	7%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	5,305
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	5,305	0.077	408.49	5,305	0.077	408.49	0.00	0.00%	18.82%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**408.49**			**408.49**	**0.00**	**0.00%**	**18.82%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	9.04%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	10.6446	1,064.46	100	11.4098	1,140.98	76.52	7.19%	52.56%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0028	0.28	100	0.0028	0.28	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,260.91**			**1,337.43**	**76.52**	**6.07%**	**61.60%**
Retail Transmission Rate – Network Service Rate	100	0.6311	63.11	100	0.6395	63.95	0.84	1.33%	2.95%
Retail Transmission Rate – Line and Transformation Connection Service Rate	100	0.5475	54.75	100	0.5543	55.43	0.68	1.25%	2.55%
Sub-Total: Retail Transmission			**117.86**			**119.38**	**1.52**	**1.29%**	**5.50%**
Sub-Total: Delivery			**1,378.77**			**1,456.81**	**78.04**	**5.66%**	**67.10%**
Wholesale Market Service Rate	5,305	0.0036	19.10	5,305	0.0036	19.10	0.00	0.00%	0.88%
Rural Rate Protection Charge	5,305	0.0003	1.59	5,305	0.0003	1.59	0.00	0.00%	0.07%
Ontario Electricity Support Program Charge	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**20.94**			**20.94**	**0.00**	**0.00%**	**0.96%**
Debt Retirement Charge (DRC)	5,000	0.007	**35.00**	5,000	0.007	**35.00**	**0.00**	**0.00%**	**1.61%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,843.19**			**1,921.24**	**78.04**	**4.23%**	**88.50%**
HST		0.13	239.62		0.13	249.76	10.15	4.23%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,082.81**			**2,171.00**	**88.19**	**4.23%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,082.81**			**2,171.00**	**88.19**	**4.23%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	200,000
Peak (kW)	500
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	206,800
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	206,800	0.077	15,923.60	206,800	0.077	15,923.60	0.00	0.00%	60.86%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15,923.60**			**15,923.60**	**0.00**	**0.00%**	**60.86%**
Service Charge (includes Meter Charge for 1 meter point)	1	1255.93	1,255.93	1	1270.37	1,270.37	14.44	1.15%	4.86%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.01%
Distribution Volumetric Rate (ST Common Line Charge)	500	1.4137	706.83	500	1.4497	724.83	18.00	2.55%	2.77%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	-0.1367	-68.34	500	-0.1367	-68.34	0.00	0.00%	-0.26%
Volumetric Global Adjustment Account Rider	206,800	0	0.00	206,800	0	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,898.24**			**1,930.69**	**32.44**	**1.71%**	**7.38%**
Retail Transmission Rate – Network Service Rate	500	3.4866	1,743.32	500	3.5367	1,768.35	25.03	1.44%	6.76%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.6022	1,301.08	500	2.6514	1,325.70	24.62	1.89%	5.07%
Sub-Total: Retail Transmission			**3,044.41**			**3,094.05**	**49.64**	**1.63%**	**11.83%**
Sub-Total: Delivery			**4,942.65**			**5,024.74**	**82.09**	**1.66%**	**19.20%**
Wholesale Market Service Rate	206,800	0.0036	744.48	206,800	0.0036	744.48	0.00	0.00%	2.85%
Rural Rate Protection Charge	206,800	0.0003	62.04	206,800	0.0003	62.04	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**806.77**			**806.77**	**0.00**	**0.00%**	**3.08%**
Debt Retirement Charge (DRC)	200,000	0.007	**1,400.00**	200,000	0.007	**1,400.00**	**0.00**	**0.00%**	**5.35%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,073.02**			**23,155.11**	**82.09**	**0.36%**	**88.50%**
HST		0.13	2,999.49		0.13	3,010.16	10.67	0.36%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,072.51**			**26,165.27**	**92.76**	**0.36%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,072.51**			**26,165.27**	**92.76**	**0.36%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	1,601,036
Peak (kW)	2,960
Loss factor	1.034
Load factor	74%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,655,471
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,655,471	0.077	127,471.28	1,655,471	0.077	127,471.28	0.00	0.00%	66.90%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**127,471.28**			**127,471.28**	**0.00**	**0.00%**	**66.90%**
Service Charge (includes Meter Charge for 1 meter point)	1	1255.93	1,255.93	1	1270.37	1,270.37	14.44	1.15%	0.67%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate (ST Common Line Charge)	2,960	1.4137	4,184.42	2,960	1.4497	4,291.01	106.58	2.55%	2.25%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,960	-0.1367	-404.54	2,960	-0.1367	-404.54	0.00	0.00%	-0.21%
Volumetric Global Adjustment Account Rider	1,655,471	0	0.00	1,655,471	0	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**5,039.63**			**5,160.65**	**121.02**	**2.40%**	**2.71%**
Retail Transmission Rate – Network Service Rate	2,960	3.4866	10,320.48	2,960	3.5367	10,468.63	148.15	1.44%	5.49%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,960	2.6022	7,702.41	2,960	2.6514	7,848.14	145.74	1.89%	4.12%
Sub-Total: Retail Transmission			**18,022.88**			**18,316.78**	**293.89**	**1.63%**	**9.61%**
Sub-Total: Delivery			**23,062.51**			**23,477.43**	**414.91**	**1.80%**	**12.32%**
Wholesale Market Service Rate	1,655,471	0.0036	5,959.70	1,655,471	0.0036	5,959.70	0.00	0.00%	3.13%
Rural Rate Protection Charge	1,655,471	0.0003	496.64	1,655,471	0.0003	496.64	0.00	0.00%	0.26%
Ontario Electricity Support Program Charge	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**6,456.59**			**6,456.59**	**0.00**	**0.00%**	**3.39%**
Debt Retirement Charge (DRC)	1,601,036	0.007	**11,207.25**	1,601,036	0.007	**11,207.25**	**0.00**	**0.00%**	**5.88%**
Total Electricity Charge on Two-Tier RPP (before HST)			**168,197.64**			**168,612.55**	**414.91**	**0.25%**	**88.50%**
HST		0.13	21,865.69		0.13	21,919.63	53.94	0.25%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**190,063.33**			**190,532.18**	**468.85**	**0.25%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**190,063.33**			**190,532.18**	**468.85**	**0.25%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	4,000,000
Peak (kW)	10,000
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	4,136,000
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	4,136,000	0.077	318,472.00	4,136,000	0.077	318,472.00	0.00	0.00%	64.22%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**318,472.00**			**318,472.00**	**0.00**	**0.00%**	**64.22%**
Service Charge (includes Meter Charge for 1 meter point)	1	1255.93	1,255.93	1	1270.37	1,270.37	14.44	1.15%	0.26%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate (ST Common Line Charge)	10,000	1.4137	14,136.57	10,000	1.4497	14,496.64	360.08	2.55%	2.92%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10,000	-0.1367	-1,366.70	10,000	-0.1367	-1,366.70	0.00	0.00%	-0.28%
Volumetric Global Adjustment Account Rider	4,136,000	0	0.00	4,136,000	0	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**14,029.62**			**14,404.13**	**374.52**	**2.67%**	**2.90%**
Retail Transmission Rate – Network Service Rate	10,000	3.4866	34,866.48	10,000	3.5367	35,367.00	500.52	1.44%	7.13%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10,000	2.6022	26,021.64	10,000	2.6514	26,514.00	492.36	1.89%	5.35%
Sub-Total: Retail Transmission			**60,888.12**			**61,881.00**	**992.88**	**1.63%**	**12.48%**
Sub-Total: Delivery			**74,917.74**			**76,285.13**	**1,367.39**	**1.83%**	**15.38%**
Wholesale Market Service Rate	4,136,000	0.0036	14,889.60	4,136,000	0.0036	14,889.60	0.00	0.00%	3.00%
Rural Rate Protection Charge	4,136,000	0.0003	1,240.80	4,136,000	0.0003	1,240.80	0.00	0.00%	0.25%
Ontario Electricity Support Program Charge	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**16,130.65**			**16,130.65**	**0.00**	**0.00%**	**3.25%**
Debt Retirement Charge (DRC)	4,000,000	0.007	**28,000.00**	4,000,000	0.007	**28,000.00**	**0.00**	**0.00%**	**5.65%**
Total Electricity Charge on Two-Tier RPP (before HST)			**437,520.39**			**438,887.78**	**1,367.39**	**0.31%**	**88.50%**
HST		0.13	56,877.65		0.13	57,055.41	177.76	0.31%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**494,398.04**			**495,943.20**	**1,545.15**	**0.31%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**494,398.04**			**495,943.20**	**1,545.15**	**0.31%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	14.35%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**14.35%**
Service Charge	1	36.66	36.66	1	37.37	37.37	0.71	1.94%	69.63%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	0.0298	2.98	100	0.0303	3.03	0.05	1.68%	5.65%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0000	0.00	100	0.00002	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**39.64**			**40.40**	**0.76**	**1.92%**	**75.28%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	1.32%
Sub-Total: Distribution			**40.35**			**41.11**	**0.76**	**1.88%**	**76.60%**
Retail Transmission Rate – Network Service Rate	109	0.0048	0.52	109	0.0047	0.51	-0.01	-1.47%	0.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	109	0.0038	0.41	109	0.0038	0.41	0.00	0.13%	0.77%
Sub-Total: Retail Transmission			**0.94**			**0.93**	**-0.01**	**-0.76%**	**1.73%**
Sub-Total: Delivery			**41.29**			**42.04**	**0.75**	**1.82%**	**78.33%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	0.73%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.06%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.47%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**1.26%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**1.30%**
Total Electricity Charge on Two-Tier RPP (before HST)			**50.36**			**51.12**	**0.75**	**1.49%**	**95.24%**
HST		0.13	6.55		0.13	6.65	0.10	1.49%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**56.91**			**57.76**	**0.85**	**1.49%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.03		-0.08	-4.09	-0.06	-1.49%	-7.62%
Total Amount on Two-Tier RPP			**52.88**			**53.67**	**0.79**	**1.49%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	364
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	397
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	364	0.077	28.03	364	0.077	28.03	0.00	0.00%	30.77%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**28.03**			**28.03**	**0.00**	**0.00%**	**30.77%**
Service Charge	1	36.66	36.66	1	37.37	37.37	0.71	1.94%	41.03%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	364	0.0298	10.85	364	0.0303	11.03	0.18	1.68%	12.11%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	364	0.0000	0.01	364	0.0000	0.01	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**47.52**			**48.41**	**0.89**	**1.88%**	**53.15%**
Line Losses on Cost of Power	33	0.0770	2.58	33	0.0770	2.58	0.00	0.00%	2.83%
Sub-Total: Distribution			**50.10**			**50.99**	**0.89**	**1.78%**	**55.98%**
Retail Transmission Rate – Network Service Rate	397	0.0048	1.90	397	0.0047	1.87	-0.03	-1.47%	2.05%
Retail Transmission Rate – Line and Transformation Connection Service Rate	397	0.0038	1.51	397	0.0038	1.51	0.00	0.13%	1.66%
Sub-Total: Retail Transmission			**3.40**			**3.38**	**-0.03**	**-0.76%**	**3.71%**
Sub-Total: Delivery			**53.50**			**54.37**	**0.87**	**1.62%**	**59.69%**
Wholesale Market Service Rate	397	0.0036	1.43	397	0.0036	1.43	0.00	0.00%	1.57%
Rural Rate Protection Charge	397	0.0003	0.12	397	0.0003	0.12	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.27%
Sub-Total: Regulatory			**1.80**			**1.80**	**0.00**	**0.00%**	**1.98%**
Debt Retirement Charge (DRC)	364	0.007	**2.55**	364	0.007	**2.55**	**0.00**	**0.00%**	**2.80%**
Total Electricity Charge on Two-Tier RPP (before HST)			**85.88**			**86.74**	**0.87**	**1.01%**	**95.24%**
HST		0.13	11.16		0.13	11.28	0.11	1.01%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**97.04**			**98.02**	**0.98**	**1.01%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.87		-0.08	-6.94	-0.07	-1.01%	-7.62%
Total Amount on Two-Tier RPP			**90.17**			**91.08**	**0.91**	**1.01%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1092
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	31.07%
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.11%
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**43.18%**
Service Charge	1	36.66	36.66	1	37.37	37.37	0.71	1.94%	20.11%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0298	29.80	1,000	0.0303	30.30	0.50	1.68%	16.30%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	0.0000	0.02	1,000	0.0000	0.02	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**66.48**			**67.69**	**1.21**	**1.82%**	**36.42%**
Line Losses on Cost of Power	92	0.0900	8.28	92	0.0900	8.28	0.00	0.00%	4.45%
Sub-Total: Distribution			**74.76**			**75.97**	**1.21**	**1.62%**	**40.88%**
Retail Transmission Rate – Network Service Rate	1,092	0.0048	5.21	1,092	0.0047	5.13	-0.08	-1.47%	2.76%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,092	0.0038	4.14	1,092	0.0038	4.15	0.01	0.13%	2.23%
Sub-Total: Retail Transmission			**9.35**			**9.28**	**-0.07**	**-0.76%**	**4.99%**
Sub-Total: Delivery			**84.11**			**85.25**	**1.14**	**1.35%**	**45.87%**
Wholesale Market Service Rate	1,092	0.0036	3.93	1,092	0.0036	3.93	0.00	0.00%	2.12%
Rural Rate Protection Charge	1,092	0.0003	0.33	1,092	0.0003	0.33	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%
Sub-Total: Regulatory			**4.51**			**4.51**	**0.00**	**0.00%**	**2.43%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.77%**
Total Electricity Charge on Two-Tier RPP (before HST)			**175.87**			**177.01**	**1.14**	**0.65%**	**95.24%**
HST		0.13	22.86		0.13	23.01	0.15	0.65%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**198.74**			**200.02**	**1.29**	**0.65%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.07		-0.08	-14.16	-0.09	-0.65%	-7.62%
Total Amount on Two-Tier RPP			**184.67**			**185.86**	**1.20**	**0.65%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	20
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	21.84
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	20	0.077	1.54	20	0.077	1.54	0.00	0.00%	16.65%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1.54**			**1.54**	**0.00**	**0.00%**	**16.65%**
Service Charge	1	3.57	3.57	1	3.72	3.72	0.15	4.20%	40.21%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.06%
Distribution Volumetric Rate	20	0.1354	2.71	20	0.1383	2.77	0.06	2.14%	29.90%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	20	-0.0001	0.00	20	-0.0001	0.00	0.00	0.00%	-0.01%
Sub-Total: Distribution (excluding pass through)			**6.28**			**6.49**	**0.21**	**3.31%**	**70.16%**
Line Losses on Cost of Power	2	0.0770	0.14	2	0.0770	0.14	0.00	0.00%	1.53%
Sub-Total: Distribution			**6.42**			**6.63**	**0.21**	**3.24%**	**71.69%**
Retail Transmission Rate – Network Service Rate	22	0.0047	0.10	22	0.0038	0.08	-0.02	-18.35%	0.91%
Retail Transmission Rate – Line and Transformation Connection Service Rate	22	0.0043	0.09	22	0.0036	0.08	-0.01	-15.52%	0.86%
Sub-Total: Retail Transmission			**0.20**			**0.16**	**-0.03**	**-17.00%**	**1.76%**
Sub-Total: Delivery			**6.62**			**6.80**	**0.17**	**2.64%**	**73.46%**
Wholesale Market Service Rate	22	0.0036	0.08	22	0.0036	0.08	0.00	0.00%	0.85%
Rural Rate Protection Charge	22	0.0003	0.01	22	0.0003	0.01	0.00	0.00%	0.07%
Ontario Electricity Support Program Charge	22	0.0000	0.00	22	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	2.70%
Sub-Total: Regulatory			**0.34**			**0.34**	**0.00**	**0.00%**	**3.62%**
Debt Retirement Charge (DRC)	20	0.007	**0.14**	20	0.007	**0.14**	**0.00**	**0.00%**	**1.51%**
Total Electricity Charge on Two-Tier RPP (before HST)			**8.64**			**8.81**	**0.17**	**2.02%**	**95.24%**
HST		0.13	1.12		0.13	1.15	0.02	2.02%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**9.76**			**9.96**	**0.20**	**2.02%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-0.69		-0.08	-0.70	-0.01	-2.02%	-7.62%
Total Amount on Two-Tier RPP			**9.07**			**9.25**	**0.18**	**2.02%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	71
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	77.532
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	71	0.077	5.47	71	0.077	5.47	0.00	0.00%	24.63%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**5.47**			**5.47**	**0.00**	**0.00%**	**24.63%**
Service Charge	1	3.57	3.57	1	3.72	3.72	0.15	4.20%	16.76%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	71	0.1354	9.61	71	0.1383	9.82	0.21	2.14%	44.24%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	71	-0.0001	0.00	71	-0.0001	0.00	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**13.19**			**13.54**	**0.36**	**2.70%**	**61.01%**
Line Losses on Cost of Power	7	0.0770	0.50	7	0.0770	0.50	0.00	0.00%	2.27%
Sub-Total: Distribution			**13.69**			**14.04**	**0.36**	**2.60%**	**63.27%**
Retail Transmission Rate – Network Service Rate	78	0.0047	0.36	78	0.0038	0.30	-0.07	-18.35%	1.34%
Retail Transmission Rate – Line and Transformation Connection Service Rate	78	0.0043	0.33	78	0.0036	0.28	-0.05	-15.52%	1.27%
Sub-Total: Retail Transmission			**0.70**			**0.58**	**-0.12**	**-17.00%**	**2.61%**
Sub-Total: Delivery			**14.38**			**14.62**	**0.24**	**1.65%**	**65.88%**
Wholesale Market Service Rate	78	0.0036	0.28	78	0.0036	0.28	0.00	0.00%	1.26%
Rural Rate Protection Charge	78	0.0003	0.02	78	0.0003	0.02	0.00	0.00%	0.10%
Ontario Electricity Support Program Charge	78	0.0000	0.00	78	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.13%
Sub-Total: Regulatory			**0.55**			**0.55**	**0.00**	**0.00%**	**2.49%**
Debt Retirement Charge (DRC)	71	0.007	**0.50**	71	0.007	**0.50**	**0.00**	**0.00%**	**2.24%**
Total Electricity Charge on Two-Tier RPP (before HST)			**20.90**			**21.14**	**0.24**	**1.14%**	**95.24%**
HST		0.13	2.72		0.13	2.75	0.03	1.14%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**23.62**			**23.89**	**0.27**	**1.14%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.67		-0.08	-1.69	-0.02	-1.14%	-7.62%
Total Amount on Two-Tier RPP			**21.95**			**22.20**	**0.25**	**1.14%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	200
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	218.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	200	0.077	15.40	200	0.077	15.40	0.00	0.00%	28.03%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15.40**			**15.40**	**0.00**	**0.00%**	**28.03%**
Service Charge	1	3.57	3.57	1	3.72	3.72	0.15	4.20%	6.77%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	200	0.1354	27.08	200	0.1383	27.66	0.58	2.14%	50.35%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	200	-0.0001	-0.01	200	-0.0001	-0.01	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**30.64**			**31.37**	**0.73**	**2.38%**	**57.11%**
Line Losses on Cost of Power	18	0.0770	1.42	18	0.0770	1.42	0.00	0.00%	2.58%
Sub-Total: Distribution			**32.06**			**32.79**	**0.73**	**2.28%**	**59.69%**
Retail Transmission Rate – Network Service Rate	218	0.0047	1.03	218	0.0038	0.84	-0.19	-18.35%	1.52%
Retail Transmission Rate – Line and Transformation Connection Service Rate	218	0.0043	0.94	218	0.0036	0.79	-0.15	-15.52%	1.44%
Sub-Total: Retail Transmission			**1.96**			**1.63**	**-0.33**	**-17.00%**	**2.97%**
Sub-Total: Delivery			**34.02**			**34.42**	**0.40**	**1.16%**	**62.65%**
Wholesale Market Service Rate	218	0.0036	0.79	218	0.0036	0.79	0.00	0.00%	1.43%
Rural Rate Protection Charge	218	0.0003	0.07	218	0.0003	0.07	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	218	0.0000	0.00	218	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.46%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	**0.00%**	**2.01%**
Debt Retirement Charge (DRC)	200	0.007	**1.40**	200	0.007	**1.40**	**0.00**	**0.00%**	**2.55%**
Total Electricity Charge on Two-Tier RPP (before HST)			**51.93**			**52.32**	**0.40**	**0.76%**	**95.24%**
HST		0.13	6.75		0.13	6.80	0.05	0.76%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**58.68**			**59.12**	**0.45**	**0.76%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.15		-0.08	-4.19	-0.03	-0.76%	-7.62%
Total Amount on Two-Tier RPP			**54.52**			**54.94**	**0.42**	**0.76%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	28.13%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**28.13%**
Service Charge	1	4.33	4.33	1	4.77	4.77	0.44	10.16%	17.43%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	100	0.1043	10.43	100	0.1069	10.69	0.26	2.49%	39.06%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.0000	0.00	100	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**14.77**			**15.47**	**0.70**	**4.74%**	**56.51%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	2.59%
Sub-Total: Distribution			**15.47**			**16.17**	**0.70**	**4.52%**	**59.10%**
Retail Transmission Rate – Network Service Rate	109	0.0047	0.51	109	0.0038	0.42	-0.09	-18.35%	1.53%
Retail Transmission Rate – Line and Transformation Connection Service Rate	109	0.0043	0.47	109	0.0036	0.40	-0.07	-15.52%	1.45%
Sub-Total: Retail Transmission			**0.98**			**0.81**	**-0.17**	**-17.00%**	**2.98%**
Sub-Total: Delivery			**16.46**			**16.99**	**0.53**	**3.24%**	**62.08%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	1.44%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.91%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**2.47%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**2.56%**
Total Electricity Charge on Two-Tier RPP (before HST)			**25.53**			**26.06**	**0.53**	**2.09%**	**95.24%**
HST		0.13	3.32		0.13	3.39	0.07	2.09%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**28.85**			**29.45**	**0.60**	**2.09%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-2.04		-0.08	-2.09	-0.04	-2.09%	-7.62%
Total Amount on Two-Tier RPP			**26.81**			**27.37**	**0.56**	**2.09%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	517
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	564.564
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	517	0.077	39.81	517	0.077	39.81	0.00	0.00%	33.32%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**39.81**			**39.81**	**0.00**	**0.00%**	**33.32%**
Service Charge	1	4.33	4.33	1	4.77	4.77	0.44	10.16%	3.99%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	517	0.1043	53.92	517	0.1069	55.27	1.34	2.49%	46.26%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	517	0.0000	-0.01	517	0.0000	-0.01	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**58.25**			**60.04**	**1.78**	**3.06%**	**50.25%**
Line Losses on Cost of Power	48	0.0770	3.66	48	0.0770	3.66	0.00	0.00%	3.07%
Sub-Total: Distribution			**61.92**			**63.70**	**1.78**	**2.88%**	**53.31%**
Retail Transmission Rate – Network Service Rate	565	0.0047	2.65	565	0.0038	2.17	-0.49	-18.35%	1.81%
Retail Transmission Rate – Line and Transformation Connection Service Rate	565	0.0043	2.42	565	0.0036	2.05	-0.38	-15.52%	1.71%
Sub-Total: Retail Transmission			**5.07**			**4.21**	**-0.86**	**-17.00%**	**3.52%**
Sub-Total: Delivery			**66.99**			**67.91**	**0.92**	**1.38%**	**56.84%**
Wholesale Market Service Rate	565	0.0036	2.03	565	0.0036	2.03	0.00	0.00%	1.70%
Rural Rate Protection Charge	565	0.0003	0.17	565	0.0003	0.17	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	565	0.0000	0.00	565	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%
Sub-Total: Regulatory			**2.45**			**2.45**	**0.00**	**0.00%**	**2.05%**
Debt Retirement Charge (DRC)	517	0.007	**3.62**	517	0.007	**3.62**	**0.00**	**0.00%**	**3.03%**
Total Electricity Charge on Two-Tier RPP (before HST)			**112.87**			**113.79**	**0.92**	**0.82%**	**95.24%**
HST		0.13	14.67		0.13	14.79	0.12	0.82%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**127.54**			**128.59**	**1.04**	**0.82%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.03		-0.08	-9.10	-0.07	-0.82%	-7.62%
Total Amount on Two-Tier RPP			**118.52**			**119.48**	**0.97**	**0.82%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2184
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.38%
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	24.11%
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**36.48%**
Service Charge	1	4.33	4.33	1	4.77	4.77	0.44	10.16%	1.02%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.1043	208.60	2,000	0.1069	213.80	5.20	2.49%	45.82%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,000	0.0000	-0.02	2,000	0.0000	-0.02	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**212.92**			**218.56**	**5.64**	**2.65%**	**46.84%**
Line Losses on Cost of Power	184	0.0900	16.56	184	0.0900	16.56	0.00	0.00%	3.55%
Sub-Total: Distribution			**229.48**			**235.12**	**5.64**	**2.46%**	**50.38%**
Retail Transmission Rate – Network Service Rate	2,184	0.0047	10.26	2,184	0.0038	8.38	-1.88	-18.35%	1.80%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,184	0.0043	9.37	2,184	0.0036	7.91	-1.45	-15.52%	1.70%
Sub-Total: Retail Transmission			**19.63**			**16.29**	**-3.34**	**-17.00%**	**3.49%**
Sub-Total: Delivery			**249.11**			**251.41**	**2.30**	**0.92%**	**53.88%**
Wholesale Market Service Rate	2,184	0.0036	7.86	2,184	0.0036	7.86	0.00	0.00%	1.68%
Rural Rate Protection Charge	2,184	0.0003	0.66	2,184	0.0003	0.66	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	2,184	0.0000	0.00	2,184	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**8.77**			**8.77**	**0.00**	**0.00%**	**1.88%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.00%**
Total Electricity Charge on Two-Tier RPP (before HST)			**442.12**			**444.43**	**2.30**	**0.52%**	**95.24%**
HST		0.13	57.48		0.13	57.78	0.30	0.52%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**499.60**			**502.20**	**2.60**	**0.52%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-35.37		-0.08	-35.55	-0.18	-0.52%	-7.62%
Total Amount on Two-Tier RPP			**464.23**			**466.65**	**2.42**	**0.52%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AUR	WHSI_RES
Monthly Consumption (kWh)	350	350
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	370	365
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	38.46%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**38.46%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		20.51%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.84%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		11.54%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**41.03%**	**39.89%**
Service Charge	1	29.98	29.98	1	30.78	30.78	0.80	2.67%	43.92%	42.70%
Fixed Acquisition Agreement Rider	1	-0.30	-0.30	1	0.00	0.00	0.30	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	350	0.0000	0.00	350	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	350	0.0000	0.00	350	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**29.68**			**30.78**	**1.10**	**3.71%**	**43.92%**	**42.70%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.13%	1.10%
Line Losses on Cost of Power (based on two-tier RPP prices)	15	0.0770	1.16	20	0.0770	1.54	0.37	32.25%	2.19%	2.13%
Line Losses on Cost of Power (based on TOU prices)	15	0.0822	1.24	20	0.0822	1.64	0.40	32.25%	2.34%	2.27%
Sub-Total: Distribution (based on two-tier RPP prices)			**31.63**			**33.11**	**1.47**	**4.66%**	**47.24%**	**45.93%**
Sub-Total: Distribution (based on TOU prices)			**31.71**			**33.21**	**1.50**	**4.73%**	**47.39%**	**46.07%**
Retail Transmission Rate – Network Service Rate	365	0.0072	2.63	370	0.0073	2.70	0.07	2.74%	3.85%	3.75%
Retail Transmission Rate – Line and Transformation Connection Service Rate	365	0.0056	2.03	370	0.0062	2.29	0.26	12.82%	3.27%	3.18%
Sub-Total: Retail Transmission			**4.66**			**4.99**	**0.33**	**7.13%**	**7.13%**	**6.93%**
Sub-Total: Delivery (based on two-tier RPP prices)			**36.29**			**38.10**	**1.81**	**4.98%**	**54.37%**	**52.86%**
Sub-Total: Delivery (based on TOU prices)			**36.37**			**38.20**	**1.83**	**5.04%**	**54.51%**	**53.00%**
Wholesale Market Service Rate	365	0.0036	1.31	370	0.0036	1.33	0.02	1.33%	1.90%	1.85%
Rural Rate Protection Charge	365	0.0003	0.11	370	0.0003	0.11	0.00	1.33%	0.16%	0.15%
Ontario Electricity Support Program Charge	365	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.36%	0.35%
Sub-Total: Regulatory			**1.67**			**1.69**	**0.02**	**1.13%**	**2.42%**	**2.35%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**64.92**			**66.74**	**1.83**	**2.81%**	**95.24%**	
HST		0.13	8.44		0.13	8.68	0.24	2.81%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**73.36**			**75.42**	**2.06**	**2.81%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.19		-0.08	-5.34	-0.15	-2.81%	-7.62%	
Total Amount on Two-Tier RPP			**68.16**			**70.08**	**1.92**	**2.81%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**66.80**			**68.65**	**1.85**	**2.77%**		**95.24%**
HST		0.13	8.68		0.13	8.92	0.24	2.77%		12.38%
Total Electricity Charge on TOU (including HST)			**75.49**			**77.58**	**2.09**	**2.77%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.34		-0.08	-5.49	-0.15	-2.77%		-7.62%
Total Amount on TOU			**70.14**			**72.08**	**1.94**	**2.77%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AUR	WHSI_RES
Monthly Consumption (kWh)	600	600
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	634	626
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	47.99%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**46.20**			**46.20**	**0.00**	**0.00%**	**47.99%**	
TOU-Off Peak	390	0.065	25.35	390	0.065	25.35	0.00	0.00%		25.42%
TOU-Mid Peak	102	0.095	9.69	102	0.095	9.69	0.00	0.00%		9.72%
TOU-On Peak	108	0.132	14.26	108	0.132	14.26	0.00	0.00%		14.30%
Sub-Total: Energy (TOU)			**49.30**			**49.30**	0.00	0.00%	**51.20%**	**49.44%**
Service Charge	1	29.98	29.98	1	30.78	30.78	0.80	2.67%	31.97%	30.87%
Fixed Acquisition Agreement Rider	1	-0.30	-0.30	1	0.00	0.00	0.30	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	600	0.0000	0.00	600	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	600	0.0000	0.00	600	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**29.68**			**30.78**	**1.10**	**3.71%**	**31.97%**	**30.87%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.82%	0.79%
Line Losses on Cost of Power (based on two-tier RPP prices)	26	0.0770	1.99	34	0.0770	2.63	0.64	32.25%	2.74%	2.64%
Line Losses on Cost of Power (based on TOU prices)	26	0.0822	2.12	34	0.0822	2.81	0.69	32.25%	2.92%	2.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**32.46**			**34.20**	**1.74**	**5.37%**	**35.53%**	**34.30%**
Sub-Total: Distribution (based on TOU prices)			**32.59**			**34.38**	**1.79**	**5.48%**	**35.71%**	**34.48%**
Retail Transmission Rate – Network Service Rate	626	0.0072	4.51	634	0.0073	4.63	0.12	2.74%	4.81%	4.64%
Retail Transmission Rate – Line and Transformation Connection Service Rate	626	0.0056	3.49	634	0.0062	3.93	0.45	12.82%	4.08%	3.94%
Sub-Total: Retail Transmission			**7.99**			**8.56**	**0.57**	**7.13%**	**8.89%**	**8.59%**
Sub-Total: Delivery (based on two-tier RPP prices)			**40.45**			**42.77**	**2.31**	**5.72%**	**44.42%**	**42.89%**
Sub-Total: Delivery (based on TOU prices)			**40.59**			**42.94**	**2.36**	**5.80%**	**44.60%**	**43.07%**
Wholesale Market Service Rate	626	0.0036	2.25	634	0.0036	2.28	0.03	1.33%	2.37%	2.29%
Rural Rate Protection Charge	626	0.0003	0.19	634	0.0003	0.19	0.00	1.33%	0.20%	0.19%
Ontario Electricity Support Program Charge	626	0.0000	0.00	634	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.26%	0.25%
Sub-Total: Regulatory			**2.69**			**2.72**	**0.03**	**1.21%**	**2.83%**	**2.73%**
Debt Retirement Charge (DRC)	600	0.000	**0.00**	600	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**89.34**			**91.69**	**2.34**	**2.62%**	**95.24%**	
HST		0.13	11.61		0.13	11.92	0.30	2.62%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**100.96**			**103.61**	**2.65**	**2.62%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.15		-0.08	-7.34	-0.19	-2.62%	-7.62%	
Total Amount on Two-Tier RPP			**93.81**			**96.27**	**2.46**	**2.62%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**92.57**			**94.96**	**2.39**	**2.58%**		**95.24%**
HST		0.13	12.03		0.13	12.34	0.31	2.58%		12.38%
Total Electricity Charge on TOU (including HST)			**104.61**			**107.31**	**2.70**	**2.58%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.41		-0.08	-7.60	-0.19	-2.58%		-7.62%
Total Amount on TOU			**97.20**			**99.71**	**2.51**	**2.58%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AUR	WHSI_RES
Monthly Consumption (kWh)	750	750
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	793	782
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	40.31%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.78%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**52.09%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		27.25%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		10.42%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		15.32%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**53.76%**	**52.99%**
Service Charge	1	29.98	29.98	1	30.78	30.78	0.80	2.67%	26.85%	26.47%
Fixed Acquisition Agreement Rider	1	-0.30	-0.30	1	0.00	0.00	0.30	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0000	0.00	750	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**29.68**			**30.78**	**1.10**	**3.71%**	**26.85%**	**26.47%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.69%	0.68%
Line Losses on Cost of Power (based on two-tier RPP prices)	32	0.0900	2.91	43	0.0900	3.85	0.94	32.25%	3.36%	3.31%
Line Losses on Cost of Power (based on TOU prices)	32	0.0822	2.66	43	0.0822	3.51	0.86	32.25%	3.06%	3.02%
Sub-Total: Distribution (based on two-tier RPP prices)			**33.38**			**35.42**	**2.04**	**6.11%**	**30.90%**	**30.46%**
Sub-Total: Distribution (based on TOU prices)			**33.13**			**35.08**	**1.96**	**5.91%**	**30.61%**	**30.17%**
Retail Transmission Rate – Network Service Rate	782	0.0072	5.63	793	0.0073	5.79	0.15	2.74%	5.05%	4.98%
Retail Transmission Rate – Line and Transformation Connection Service Rate	782	0.0056	4.36	793	0.0062	4.92	0.56	12.82%	4.29%	4.23%
Sub-Total: Retail Transmission			**9.99**			**10.70**	**0.71**	**7.13%**	**9.34%**	**9.20%**
Sub-Total: Delivery (based on two-tier RPP prices)			**43.37**			**46.12**	**2.75**	**6.34%**	**40.24%**	**39.66%**
Sub-Total: Delivery (based on TOU prices)			**43.12**			**45.78**	**2.67**	**6.19%**	**39.94%**	**39.37%**
Wholesale Market Service Rate	782	0.0036	2.82	793	0.0036	2.85	0.04	1.33%	2.49%	2.45%
Rural Rate Protection Charge	782	0.0003	0.23	793	0.0003	0.24	0.00	1.33%	0.21%	0.20%
Ontario Electricity Support Program Charge	782	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.22%	0.21%
Sub-Total: Regulatory			**3.30**			**3.34**	**0.04**	**1.23%**	**2.92%**	**2.87%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Bill on Two-Tier RPP (before HST)			**106.37**			**109.16**	**2.79**	**2.62%**	**95.24%**	
HST		0.13	13.83		0.13	14.19	0.36	2.62%	12.38%	
Total Bill on Two-Tier RPP (including HST)			**120.20**			**123.35**	**3.15**	**2.62%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.51		-0.08	-8.73	-0.22	-2.62%	-7.62%	
Total Bill on Two-Tier RPP			**111.69**			**114.62**	**2.93**	**2.62%**	**100.00%**	
Total Bill on TOU (before HST)			**108.04**			**110.75**	**2.71**	**2.51%**		**95.24%**
HST		0.13	14.04		0.13	14.40	0.35	2.51%		12.38%
Total Bill on TOU (including HST)			**122.08**			**125.14**	**3.06**	**2.51%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.64		-0.08	-8.86	-0.22	-2.51%		-7.62%
Total Bill on TOU			**113.44**			**116.28**	**2.85**	**2.51%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AUR	WHSI_RES
Monthly Consumption (kWh)	1400	1400
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	1480	1460
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	24.05%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	37.48%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**61.53%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		31.44%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		12.02%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		17.68%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**59.88%**	**61.15%**
Service Charge	1	29.98	29.98	1	30.78	30.78	0.80	2.67%	16.02%	16.36%
Fixed Acquisition Agreement Rider	1	-0.30	-0.30	1	0.00	0.00	0.30	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**29.68**			**30.78**	**1.10**	**3.71%**	**16.02%**	**16.36%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.41%	0.42%
Line Losses on Cost of Power (based on two-tier RPP prices)	60	0.0900	5.43	80	0.0900	7.18	1.75	32.25%	3.74%	3.82%
Line Losses on Cost of Power (based on TOU prices)	60	0.0822	4.96	80	0.0822	6.56	1.60	32.25%	3.41%	3.49%
Sub-Total: Distribution (based on two-tier RPP prices)			**35.90**			**38.75**	**2.85**	**7.94%**	**20.17%**	**20.60%**
Sub-Total: Distribution (based on TOU prices)			**35.43**			**38.13**	**2.70**	**7.62%**	**19.85%**	**20.27%**
Retail Transmission Rate – Network Service Rate	1,460	0.0072	10.51	1,480	0.0073	10.80	0.29	2.74%	5.62%	5.74%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,460	0.0056	8.13	1,480	0.0062	9.17	1.04	12.82%	4.78%	4.88%
Sub-Total: Retail Transmission			**18.65**			**19.98**	**1.33**	**7.13%**	**10.40%**	**10.62%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.55**			**58.73**	**4.18**	**7.67%**	**30.57%**	**31.22%**
Sub-Total: Delivery (based on TOU prices)			**54.07**			**58.10**	**4.03**	**7.45%**	**30.25%**	**30.89%**
Wholesale Market Service Rate	1,460	0.0036	5.26	1,480	0.0036	5.33	0.07	1.33%	2.77%	2.83%
Rural Rate Protection Charge	1,460	0.0003	0.44	1,480	0.0003	0.44	0.01	1.33%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,460	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**5.95**			**6.02**	**0.08**	**1.28%**	**3.13%**	**3.20%**
Debt Retirement Charge (DRC)	1,400	0.0000	**0.00**	1,400	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**178.69**			**182.95**	**4.26**	**2.38%**	**95.24%**	
HST		0.13	23.23		0.13	23.78	0.55	2.38%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**201.92**			**206.73**	**4.81**	**2.38%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.30		-0.08	-14.64	-0.34	-2.38%	-7.62%	
Total Amount on Two-Tier RPP			**187.63**			**192.10**	**4.47**	**2.38%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**175.04**			**179.15**	**4.11**	**2.35%**		**95.24%**
HST		0.13	22.76		0.13	23.29	0.53	2.35%		12.38%
Total Electricity Charge on TOU (including HST)			**197.80**			**202.44**	**4.64**	**2.35%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.00		-0.08	-14.33	-0.33	-2.35%		-7.62%
Total Amount on TOU			**183.80**			**188.11**	**4.31**	**2.35%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AUGe	WHSI_GS<50
Monthly Consumption (kWh)	1000	1000
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1057	1043.1
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	35.26%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	13.74%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**49.00%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		25.56%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.77%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		14.37%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**50.16%**	**49.70%**
Service Charge	1	25.19	25.19	1	30.26	30.26	5.07	20.13%	18.48%	18.30%
Fixed Acquisition Agreement Rider	1	-0.25	-0.25	1	0.00	0.00	0.25	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0145	14.50	1,000	0.0174	17.40	2.90	20.00%	10.62%	10.53%
Volumetric Acquisition Agreement Rider	1,000	-0.0002	-0.20	1,000	0.0000	0.00	0.20	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**39.24**			**47.66**	**8.42**	**21.46%**	**29.10%**	**28.83%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.48%	0.48%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.88	57	0.0900	5.13	1.25	32.25%	3.13%	3.10%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	57	0.0822	4.68	1.14	32.25%	2.86%	2.83%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.91**			**53.58**	**9.67**	**22.03%**	**32.71%**	**32.41%**
Sub-Total: Distribution (based on TOU prices)			**43.57**			**53.13**	**9.56**	**21.95%**	**32.44%**	**32.14%**
Retail Transmission Rate – Network Service Rate	1,043	0.0065	6.78	1,057	0.0056	5.92	-0.86	-12.70%	3.61%	3.58%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,043	0.0053	5.49	1,057	0.0046	4.86	-0.62	-11.37%	2.97%	2.94%
Sub-Total: Retail Transmission			**12.27**			**10.78**	**-1.48**	**-12.11%**	**6.58%**	**6.52%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.18**			**64.36**	**8.19**	**14.57%**	**39.30%**	**38.93%**
Sub-Total: Delivery (based on TOU prices)			**55.84**			**63.91**	**8.08**	**14.47%**	**39.02%**	**38.66%**
Wholesale Market Service Rate	1,043	0.0036	3.76	1,057	0.0036	3.81	0.05	1.33%	2.32%	2.30%
Rural Rate Protection Charge	1,043	0.0003	0.31	1,057	0.0003	0.32	0.00	1.33%	0.19%	0.19%
Ontario Electricity Support Program Charge	1,043	0.0000	0.00	1,057	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.15%	0.15%
Sub-Total: Regulatory			**4.32**			**4.37**	**0.05**	**1.26%**	**2.67%**	**2.64%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.27%**	**4.23%**
Total Electricty Charge on Two-Tier RPP			**147.74**			**155.98**	**8.24**	**5.58%**	**95.24%**	
HST		0.13	19.21		0.13	20.28	1.07	5.58%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**166.95**			**176.26**	**9.31**	**5.58%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-11.82		-0.08	-12.48	-0.66	-5.58%	-7.62%	
Total Amount on Two-Tier RPP			**155.13**			**163.78**	**8.65**	**5.58%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**149.32**			**157.45**	**8.13**	**5.45%**		**95.24%**
HST		0.13	19.41		0.13	20.47	1.06	5.45%		12.38%
Total Electricity Charge on TOU (including HST)			**168.73**			**177.91**	**9.19**	**5.45%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-11.95		-0.08	-12.60	-0.65	-5.45%		-7.62%
Total Amount on TOU			**156.78**			**165.32**	**8.54**	**5.45%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AUGe	WHSI_GS<50
Monthly Consumption (kWh)	2,695	2,695
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	2849	2811
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	14.33%	
Energy Second Tier (kWh)	1,945	0.090	175.05	1,945	0.090	175.05	0.00	0.00%	43.43%	
Sub-Total: Energy (RPP)			**232.80**			**232.80**	**0.00**	**0.00%**	**57.76%**	
TOU-Off Peak	1,752	0.065	113.86	1,752	0.065	113.86	0.00	0.00%		29.21%
TOU-Mid Peak	458	0.095	43.52	458	0.095	43.52	0.00	0.00%		11.16%
TOU-On Peak	485	0.132	64.03	485	0.132	64.03	0.00	0.00%		16.43%
Sub-Total: Energy (TOU)			**221.42**			**221.42**	0.00	0.00%	**54.94%**	**56.80%**
Service Charge	1	25.19	25.19	1	30.26	30.26	5.07	20.13%	7.51%	7.76%
Fixed Acquisition Agreement Rider	1	-0.25	-0.25	1	0.00	0.00	0.25	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	2,695	0.0145	39.08	2,695	0.0174	46.89	7.82	20.00%	11.63%	12.03%
Volumetric Acquisition Agreement Rider	2,695	-0.0002	-0.54	2,695	0.0000	0.00	0.54	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**63.48**			**77.15**	**13.67**	**21.54%**	**19.14%**	**19.79%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.20%	0.20%
Line Losses on Cost of Power (based on two-tier RPP prices)	116	0.0900	10.45	154	0.0900	13.83	3.37	32.25%	3.43%	3.55%
Line Losses on Cost of Power (based on TOU prices)	116	0.0822	9.54	154	0.0822	12.62	3.08	32.25%	3.13%	3.24%
Sub-Total: Distribution (based on two-tier RPP prices)			**74.72**			**91.77**	**17.05**	**22.81%**	**22.77%**	**23.54%**
Sub-Total: Distribution (based on TOU prices)			**73.81**			**90.56**	**16.75**	**22.70%**	**22.47%**	**23.23%**
Retail Transmission Rate – Network Service Rate	2,811	0.0065	18.27	2,849	0.0056	15.95	-2.32	-12.70%	3.96%	4.09%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,811	0.0053	14.79	2,849	0.0046	13.10	-1.68	-11.37%	3.25%	3.36%
Sub-Total: Retail Transmission			**33.06**			**29.06**	**-4.00**	**-12.11%**	**7.21%**	**7.45%**
Sub-Total: Delivery (based on two-tier RPP prices)			**107.78**			**120.82**	**13.04**	**12.10%**	**29.98%**	**30.99%**
Sub-Total: Delivery (based on TOU prices)			**106.87**			**119.62**	**12.75**	**11.93%**	**29.68%**	**30.69%**
Wholesale Market Service Rate	2,811	0.0036	10.12	2,849	0.0036	10.26	0.13	1.33%	2.54%	2.63%
Rural Rate Protection Charge	2,811	0.0003	0.84	2,849	0.0003	0.85	0.01	1.33%	0.21%	0.22%
Ontario Electricity Support Program Charge	2,811	0.0000	0.00	2,849	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.21**			**11.36**	**0.15**	**1.30%**	**2.82%**	**2.91%**
Debt Retirement Charge (DRC)	2,695	0.007	**18.87**	2,695	0.007	**18.87**	**0.00**	**0.00%**	**4.68%**	**4.84%**
Total Electricty Charge on Two-Tier RPP			**370.66**			**383.85**	**13.19**	**3.56%**	**95.24%**	
HST		0.13	48.19		0.13	49.90	1.71	3.56%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**418.84**			**433.75**	**14.90**	**3.56%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.65		-0.08	-30.71	-1.06	-3.56%	-7.62%	
Total Amount on Two-Tier RPP			**389.19**			**403.04**	**13.85**	**3.56%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**358.37**			**371.27**	**12.90**	**3.60%**		**95.24%**
HST		0.13	46.59		0.13	48.26	1.68	3.60%		12.38%
Total Electricity Charge on TOU (including HST)			**404.96**			**419.53**	**14.57**	**3.60%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-28.67		-0.08	-29.70	-1.03	-3.60%		-7.62%
Total Amount on TOU			**376.29**			**389.83**	**13.54**	**3.60%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AUGe	WHSI_GS<50
Monthly Consumption (kWh)	2,000	2,000
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	2114	2086.2
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	18.94%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	36.89%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**55.83%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		28.38%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.85%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		15.96%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**53.89%**	**55.18%**
Service Charge	1	25.19	25.19	1	30.26	30.26	5.07	20.13%	9.92%	10.16%
Fixed Acquisition Agreement Rider	1	-0.25	-0.25	1	0.00	0.00	0.25	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0145	29.00	2,000	0.0174	34.80	5.80	20.00%	11.41%	11.69%
Volumetric Acquisition Agreement Rider	2,000	-0.0002	-0.40	2,000	0.0000	0.00	0.40	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**53.54**			**65.06**	**11.52**	**21.52%**	**21.34%**	**21.85%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.26%	0.27%
Line Losses on Cost of Power (based on two-tier RPP prices)	86	0.0900	7.76	114	0.0900	10.26	2.50	32.25%	3.36%	3.45%
Line Losses on Cost of Power (based on TOU prices)	86	0.0822	7.08	114	0.0822	9.37	2.28	32.25%	3.07%	3.15%
Sub-Total: Distribution (based on two-tier RPP prices)			**62.09**			**76.11**	**14.02**	**22.58%**	**24.96%**	**25.56%**
Sub-Total: Distribution (based on TOU prices)			**61.41**			**75.22**	**13.80**	**22.48%**	**24.67%**	**25.26%**
Retail Transmission Rate – Network Service Rate	2,086	0.0065	13.56	2,114	0.0056	11.84	-1.72	-12.70%	3.88%	3.98%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,086	0.0053	10.97	2,114	0.0046	9.72	-1.25	-11.37%	3.19%	3.27%
Sub-Total: Retail Transmission			**24.53**			**21.56**	**-2.97**	**-12.11%**	**7.07%**	**7.24%**
Sub-Total: Delivery (based on two-tier RPP prices)			**86.62**			**97.67**	**11.05**	**12.76%**	**32.03%**	**32.80%**
Sub-Total: Delivery (based on TOU prices)			**85.94**			**96.78**	**10.83**	**12.61%**	**31.74%**	**32.50%**
Wholesale Market Service Rate	2,086	0.0036	7.51	2,114	0.0036	7.61	0.10	1.33%	2.50%	2.56%
Rural Rate Protection Charge	2,086	0.0003	0.63	2,114	0.0003	0.63	0.01	1.33%	0.21%	0.21%
Ontario Electricity Support Program Charge	2,086	0.0000	0.00	2,114	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.39**			**8.49**	**0.11**	**1.29%**	**2.79%**	**2.85%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.59%**	**4.70%**
Total Electricty Charge on Two-Tier RPP			**279.26**			**290.42**	**11.16**	**4.00%**	**95.24%**	
HST		0.13	36.30		0.13	37.75	1.45	4.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**315.56**			**328.17**	**12.61**	**4.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-22.34		-0.08	-23.23	-0.89	-4.00%	-7.62%	
Total Amount on Two-Tier RPP			**293.22**			**304.94**	**11.72**	**4.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**272.65**			**283.59**	**10.94**	**4.01%**		**95.24%**
HST		0.13	35.44		0.13	36.87	1.42	4.01%		12.38%
Total Electricity Charge on TOU (including HST)			**308.10**			**320.46**	**12.37**	**4.01%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-21.81		-0.08	-22.69	-0.88	-4.01%		-7.62%
Total Amount on TOU			**286.28**			**297.77**	**11.49**	**4.01%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AUGe	WHSI_GS<50
Monthly Consumption (kWh)	15000	15000
Peak (kW)	0	0
Loss factor	1.057	1.0431
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	15855	15647
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.70%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	59.93%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**62.63%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		31.38%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.99%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		17.65%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**57.59%**	**61.02%**
Service Charge	1	25.19	25.19	1	30.26	30.26	5.07	20.13%	1.41%	1.50%
Fixed Acquisition Agreement Rider	1	-0.25	-0.25	1	0.00	0.00	0.25	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0145	217.50	15,000	0.0174	261.00	43.50	20.00%	12.20%	12.92%
Volumetric Acquisition Agreement Rider	15,000	-0.0002	-3.00	15,000	0.0000	0.00	3.00	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**239.44**			**291.26**	**51.82**	**21.64%**	**13.61%**	**14.42%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.04%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	646	0.0900	58.18	855	0.0900	76.95	18.77	32.25%	3.60%	3.81%
Line Losses on Cost of Power (based on TOU prices)	646	0.0822	53.12	855	0.0822	70.25	17.13	32.25%	3.28%	3.48%
Sub-Total: Distribution (based on two-tier RPP prices)			**298.42**			**369.00**	**70.59**	**23.65%**	**17.24%**	**18.27%**
Sub-Total: Distribution (based on TOU prices)			**293.35**			**362.30**	**68.95**	**23.50%**	**16.93%**	**17.94%**
Retail Transmission Rate – Network Service Rate	15,647	0.0065	101.70	15,855	0.0056	88.79	-12.91	-12.70%	4.15%	4.40%
Retail Transmission Rate – Line and Transformation Connection Service Rate	15,647	0.0053	82.29	15,855	0.0046	72.93	-9.36	-11.37%	3.41%	3.61%
Sub-Total: Retail Transmission			**184.00**			**161.72**	**-22.27**	**-12.11%**	**7.56%**	**8.01%**
Sub-Total: Delivery (based on two-tier RPP prices)			**482.41**			**530.72**	**48.31**	**10.01%**	**24.80%**	**26.28%**
Sub-Total: Delivery (based on TOU prices)			**477.34**			**524.02**	**46.68**	**9.78%**	**24.49%**	**25.95%**
Wholesale Market Service Rate	15,647	0.0036	56.33	15,855	0.0036	57.08	0.75	1.33%	2.67%	2.83%
Rural Rate Protection Charge	15,647	0.0003	4.69	15,855	0.0003	4.76	0.06	1.33%	0.22%	0.24%
Ontario Electricity Support Program Charge	15,647	0.0000	0.00	15,855	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**61.27**			**62.08**	**0.81**	**1.33%**	**2.90%**	**3.07%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.91%**	**5.20%**
Total Electricty Charge on Two-Tier RPP			**1,988.93**			**2,038.06**	**49.12**	**2.47%**	**95.24%**	
HST		0.13	258.56		0.13	264.95	6.39	2.47%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,247.49**			**2,303.00**	**55.51**	**2.47%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-159.11		-0.08	-163.04	-3.93	-2.47%	-7.62%	
Total Amount on Two-Tier RPP			**2,088.38**			**2,139.96**	**51.58**	**2.47%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**1,876.01**			**1,923.50**	**47.49**	**2.53%**		**95.24%**
HST		0.13	243.88		0.13	250.06	6.17	2.53%		12.38%
Total Electricity Charge on TOU (including HST)			**2,119.89**			**2,173.56**	**53.66**	**2.53%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-150.08		-0.08	-153.88	-3.80	-2.53%		-7.62%
Total Amount on TOU			**1,969.81**			**2,019.68**	**49.86**	**2.53%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AUGd	WHSI_GS 50>999
Monthly Consumption (kWh)	15,000	15,000
Peak (kW)	60	60
Loss factor	1.047	1.043
Load factor	34%	34%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	15,698	15,647
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,647	0.077	1,204.78	15,698	0.077	1,208.71	3.93	0.33%	52.96%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,204.78**			**1,208.71**	**3.93**	**0.33%**	**52.96%**
Service Charge	1	139.96	139.96	1	207.78	207.78	67.82	48.46%	9.10%
Fixed Acquisition Agreement Rider	1	-1.40	-1.40	1	0.00	0.00	1.40	100.00%	0.00%
Distribution Volumetric Rate	60	2.5777	154.66	60	3.9092	234.55	79.89	51.65%	10.28%
Variable Acquisition Agreement Rider	60	-0.0258	-1.55	60	0.0000	0.00	1.55	100.00%	0.00%
Sub-Total: Distribution			**291.67**			**442.33**	**150.66**	**51.65%**	**19.38%**
Retail Transmission Rate – Network Service Rate	60	2.7931	167.59	60	1.8612	111.67	-55.91	-33.36%	4.89%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	2.2465	134.79	60	1.5062	90.37	-44.42	-32.95%	3.96%
Sub-Total: Retail Transmission			**302.38**			**202.04**	**-100.33**	**-33.18%**	**8.85%**
Sub-Total: Delivery			**594.05**			**644.38**	**50.32**	**8.47%**	**28.24%**
Wholesale Market Service Rate	15,647	0.0036	56.33	15,698	0.0036	56.51	0.18	0.33%	2.48%
Rural Rate Protection Charge	15,647	0.0003	4.69	15,698	0.0003	4.71	0.02	0.33%	0.21%
Ontario Electricity Support Program Charge	15,647	0.0000	0.00	15,698	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.27**			**61.47**	**0.20**	**0.32%**	**2.69%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.60%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,965.10**			**2,019.55**	**54.45**	**2.77%**	**88.50%**
HST		0.13	255.46		0.13	262.54	7.08	2.77%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,220.57**			**2,282.10**	**61.53**	**2.77%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,220.57**			**2,282.10**	**61.53**	**2.77%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AUGd	WHSI_GS 50>999
Monthly Consumption (kWh)	61,239	61,239
Peak (kW)	177	177
Loss factor	1.047	1.043
Load factor	47%	47%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	64,087	63,878
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	63,878	0.077	4,918.64	64,087	0.077	4,934.67	16.03	0.33%	61.43%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,918.64**			**4,934.67**	**16.03**	**0.33%**	**61.43%**
Service Charge	1	139.96	139.96	1	207.78	207.78	67.82	48.46%	2.59%
Fixed Acquisition Agreement Rider	1	-1.40	-1.40	1	0.00	0.00	1.40	100.00%	0.00%
Distribution Volumetric Rate	177	2.5777	456.25	177	3.9092	691.93	235.68	51.65%	8.61%
Variable Acquisition Agreement Rider	177	-0.0258	-4.57	177	0.0000	0.00	4.57	100.00%	0.00%
Sub-Total: Distribution			**590.25**			**899.71**	**309.46**	**52.43%**	**11.20%**
Retail Transmission Rate – Network Service Rate	177	2.7931	494.38	177	1.8612	329.43	-164.95	-33.36%	4.10%
Retail Transmission Rate – Line and Transformation Connection Service Rate	177	2.2465	397.64	177	1.5062	266.60	-131.04	-32.95%	3.32%
Sub-Total: Retail Transmission			**892.01**			**596.03**	**-295.99**	**-33.18%**	**7.42%**
Sub-Total: Delivery			**1,482.26**			**1,495.74**	**13.48**	**0.91%**	**18.62%**
Wholesale Market Service Rate	63,878	0.0036	229.96	64,087	0.0036	230.71	0.75	0.33%	2.87%
Rural Rate Protection Charge	63,878	0.0003	19.16	64,087	0.0003	19.23	0.06	0.33%	0.24%
Ontario Electricity Support Program Charge	63,878	0.0000	0.00	64,087	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**249.38**			**250.19**	**0.81**	**0.33%**	**3.11%**
Debt Retirement Charge (DRC)	61,239	0.007	**428.67**	61,239	0.007	**428.67**	**0.00**	**0.00%**	**5.34%**
Total Electricity Charge on Two-Tier RPP (before HST)			**7,078.95**			**7,109.27**	**30.32**	**0.43%**	**88.50%**
HST		0.13	920.26		0.13	924.20	3.94	0.43%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,999.21**			**8,033.47**	**34.26**	**0.43%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,999.21**			**8,033.47**	**34.26**	**0.43%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AUGd	WHSI_GS 50>999
Monthly Consumption (kWh)	175,000	175,000
Peak (kW)	500	500
Loss factor	1.047	1.043
Load factor	48%	48%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	183,138	182,543
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	182,543	0.077	14,055.77	183,138	0.077	14,101.59	45.82	0.33%	62.75%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,055.77**			**14,101.59**	**45.82**	**0.33%**	**62.75%**
Service Charge	1	139.96	139.96	1	207.78	207.78	67.82	48.46%	0.92%
Fixed Acquisition Agreement Rider	1	-1.40	-1.40	1	0.00	0.00	1.40	100.00%	0.00%
Distribution Volumetric Rate	500	2.5777	1,288.85	500	3.9092	1,954.60	665.75	51.65%	8.70%
Variable Acquisition Agreement Rider	500	-0.0258	-12.90	500	0.0000	0.00	12.90	100.00%	0.00%
Sub-Total: Distribution			**1,414.51**			**2,162.38**	**747.87**	**52.87%**	**9.62%**
Retail Transmission Rate – Network Service Rate	500	2.7931	1,396.55	500	1.8612	930.60	-465.95	-33.36%	4.14%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.2465	1,123.27	500	1.5062	753.10	-370.17	-32.95%	3.35%
Sub-Total: Retail Transmission			**2,519.82**			**1,683.70**	**-836.12**	**-33.18%**	**7.49%**
Sub-Total: Delivery			**3,934.33**			**3,846.08**	**-88.25**	**-2.24%**	**17.11%**
Wholesale Market Service Rate	182,543	0.0036	657.15	183,138	0.0036	659.30	2.14	0.33%	2.93%
Rural Rate Protection Charge	182,543	0.0003	54.76	183,138	0.0003	54.94	0.18	0.33%	0.24%
Ontario Electricity Support Program Charge	182,543	0.0000	0.00	183,138	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**712.17**			**714.49**	**2.32**	**0.33%**	**3.18%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**5.45%**
Total Electricity Charge on Two-Tier RPP (before HST)			**19,927.26**			**19,887.15**	**-40.11**	**-0.20%**	**88.50%**
HST		0.13	2,590.54		0.13	2,585.33	-5.21	-0.20%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**22,517.81**			**22,472.48**	**-45.32**	**-0.20%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**22,517.81**			**22,472.48**	**-45.32**	**-0.20%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	ST	WHSI_GS >1,000kW
Monthly Consumption (kWh)	750,000	750,000
Peak (kW)	1,500	500
Loss factor	1.034	1.0326
Load factor	68%	205%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	775,500	774,450
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	774,450	0.077	59,632.65	775,500	0.077	59,713.50	80.85	0.14%	65.63%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**59,632.65**			**59,713.50**	**80.85**	**0.14%**	**65.63%**
Service Charge	1	518.85	518.85	1	1270.37	1,270.37	751.52	144.84%	1.40%
Fixed Acquisition Rider	1	-5.19	-5.19	1	0.00	0.00	5.19	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	3.82	3.82	3.82	N/A	0.00%
Distribution Volumetric Rate	500	2.7398	1,369.90	1,500	1.4497	2,174.50	804.60	58.73%	2.39%
Volumetric Acquisition Rider	500	-0.0274	-13.70	500	0.0000	0.00	13.70	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0000	0.00	1,500	-0.1367	-205.01	-205.01	0.00%	-0.23%
Volumetric Global Adjustment Rider	774,450	0.0000	0.00	775,500	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,869.86**			**3,243.68**	**1,373.82**	**73.47%**	**3.57%**
Retail Transmission Rate – Network Service Rate	500	2.7931	1,396.55	1,500	3.5367	5,305.05	3,908.50	279.87%	5.83%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.2465	1,123.27	1,500	2.6514	3,977.10	2,853.83	254.07%	4.37%
Sub-Total: Retail Transmission			**2,519.82**			**9,282.15**	**6,762.33**	**268.37%**	**10.20%**
Sub-Total: Delivery			**4,389.68**			**12,525.83**	**8,136.15**	**185.35%**	**13.77%**
Wholesale Market Service Rate	774,450	0.0036	2,788.02	775,500	0.0036	2,791.80	3.78	0.14%	3.07%
Rural Rate Protection Charge	774,450	0.0003	232.34	775,500	0.0003	232.65	0.31	0.14%	0.26%
Ontario Electricity Support Program Charge	774,450	0.0000	0.00	775,500	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**3,020.61**			**3,024.70**	**4.09**	**0.14%**	**3.32%**
Debt Retirement Charge (DRC)	750,000	0.007	**5,250.00**	750,000	0.007	**5,250.00**	**0.00**	**0.00%**	**5.77%**
Total Electricity Charge on Two-Tier RPP (before HST)			**72,292.93**			**80,514.03**	**8,221.10**	**11.37%**	**88.50%**
HST		0.13	9,398.08		0.13	10,466.82	1,068.74	11.37%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**81,691.01**			**90,980.85**	**9,289.84**	**11.37%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**81,691.01**			**90,980.85**	**9,289.84**	**11.37%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	ST	WHSI_GS >1,000kW
Monthly Consumption (kWh)	1,037,334	1,037,334
Peak (kW)	2,075	2,075
Loss factor	1.034	1.0326
Load factor	68%	68%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	1,072,603	1,071,151
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,071,151	0.077	82,478.63	1,072,603	0.077	82,590.45	111.82	0.14%	65.92%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**82,478.63**			**82,590.45**	**111.82**	**0.14%**	**65.92%**
Service Charge	1	518.85	518.85	1	1270.37	1,270.37	751.52	144.84%	1.01%
Fixed Acquisition Rider	1	-5.19	-5.19	1	0.00	0.00	5.19	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	3.82	3.82	3.82	N/A	0.00%
Distribution Volumetric Rate	2,075	2.7398	5,685.24	2,075	1.4497	3,008.14	-2,677.10	-47.09%	2.40%
Volumetric Acquisition Rider	2,075	-0.0274	-56.86	2,075	0.0000	0.00	56.86	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,075	0.0000	0.00	2,075	-0.1367	-283.60	-283.60	0.00%	-0.23%
Volumetric Global Adjustment Rider	1,071,151	0.0000	0.00	1,072,603	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**6,142.04**			**3,998.73**	**-2,143.32**	**-34.90%**	**3.19%**
Retail Transmission Rate – Network Service Rate	2,075	2.7931	5,795.84	2,075	3.5367	7,338.85	1,543.01	26.62%	5.86%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,075	2.2465	4,661.68	2,075	2.6514	5,501.81	840.12	18.02%	4.39%
Sub-Total: Retail Transmission			**10,457.52**			**12,840.66**	**2,383.14**	**22.79%**	**10.25%**
Sub-Total: Delivery			**16,599.57**			**16,839.39**	**239.82**	**1.44%**	**13.44%**
Wholesale Market Service Rate	1,071,151	0.0036	3,856.14	1,072,603	0.0036	3,861.37	5.23	0.14%	3.08%
Rural Rate Protection Charge	1,071,151	0.0003	321.35	1,072,603	0.0003	321.78	0.44	0.14%	0.26%
Ontario Electricity Support Program Charge	1,071,151	0.0000	0.00	1,072,603	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**4,177.74**			**4,183.40**	**5.66**	**0.14%**	**3.34%**
Debt Retirement Charge (DRC)	1,037,334	0.007	**7,261.34**	1,037,334	0.007	**7,261.34**	**0.00**	**0.00%**	**5.80%**
Total Electricity Charge on Two-Tier RPP (before HST)			**110,517.27**			**110,874.58**	**357.31**	**0.32%**	**88.50%**
HST		0.13	14,367.25		0.13	14,413.70	46.45	0.32%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**124,884.52**			**125,288.27**	**403.76**	**0.32%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**124,884.52**			**125,288.27**	**403.76**	**0.32%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	ST	WHSI_GS >1,000kW
Monthly Consumption (kWh)	2,000,000	2,000,000
Peak (kW)	3,500	3,500
Loss factor	1.034	1.0326
Load factor	78%	78%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	2,068,000	2,065,200
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	2,065,200	0.077	159,020.40	2,068,000	0.077	159,236.00	215.60	0.14%	67.48%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**159,020.40**			**159,236.00**	**215.60**	**0.14%**	**67.48%**
Service Charge	1	518.85	518.85	1	1270.37	1,270.37	751.52	144.84%	0.54%
Fixed Acquisition Rider	1	-5.19	-5.19	1	0.00	0.00	5.19	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	3.82	3.82	3.82	N/A	0.00%
Distribution Volumetric Rate	3,500	2.7398	9,589.30	3,500	1.4497	5,073.83	-4,515.47	-47.09%	2.15%
Volumetric Acquisition Rider	3,500	-0.0274	-95.90	3,500	0.0000	0.00	95.90	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	3,500	0.0000	0.00	3,500	-0.1367	-478.35	-478.35	0.00%	-0.20%
Volumetric Global Adjustment Rider	2,065,200	0.0000	0.00	2,068,000	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**10,007.06**			**5,869.67**	**-4,137.39**	**-41.34%**	**2.49%**
Retail Transmission Rate – Network Service Rate	3,500	2.7931	9,775.85	3,500	3.5367	12,378.45	2,602.60	26.62%	5.25%
Retail Transmission Rate – Line and Transformation Connection Service Rate	3,500	2.2465	7,862.86	3,500	2.6514	9,279.90	1,417.04	18.02%	3.93%
Sub-Total: Retail Transmission			**17,638.71**			**21,658.35**	**4,019.64**	**22.79%**	**9.18%**
Sub-Total: Delivery			**27,645.77**			**27,528.02**	**-117.75**	**-0.43%**	**11.67%**
Wholesale Market Service Rate	2,065,200	0.0036	7,434.72	2,068,000	0.0036	7,444.80	10.08	0.14%	3.15%
Rural Rate Protection Charge	2,065,200	0.0003	619.56	2,068,000	0.0003	620.40	0.84	0.14%	0.26%
Ontario Electricity Support Program Charge	2,065,200	0.0000	0.00	2,068,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**8,054.53**			**8,065.45**	**10.92**	**0.14%**	**3.42%**
Debt Retirement Charge (DRC)	2,000,000	0.007	**14,000.00**	2,000,000	0.007	**14,000.00**	**0.00**	**0.00%**	**5.93%**
Total Electricity Charge on Two-Tier RPP (before HST)			**208,720.70**			**208,829.47**	**108.77**	**0.05%**	**88.50%**
HST		0.13	27,133.69		0.13	27,147.83	14.14	0.05%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**235,854.39**			**235,977.30**	**122.91**	**0.05%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**235,854.39**			**235,977.30**	**122.91**	**0.05%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AR	NPDI_RES
Monthly Consumption (kWh)	400	400
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	427	423
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	35.96%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**35.96%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		19.21%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.34%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		10.80%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**38.37%**	**37.36%**
Service Charge	1	36.78	36.78	1	40.43	40.43	3.65	9.92%	47.20%	45.96%
Fixed Acquisition Agreement Rider	1	-0.55	-0.55	1	0.00	0.00	0.55	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0000	0.00	400	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	400	0.0009	0.36	400	0.0000	0.00	-0.36	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	400	0.0000	0.00	400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.59**			**40.43**	**3.84**	**10.49%**	**47.20%**	**45.96%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.92%	0.90%
Line Losses on Cost of Power (based on two-tier RPP prices)	23	0.0770	1.74	27	0.0770	2.05	0.32	18.26%	2.40%	2.34%
Line Losses on Cost of Power (based on TOU prices)	23	0.0822	1.85	27	0.0822	2.19	0.34	18.26%	2.56%	2.49%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.12**			**43.27**	**4.16**	**10.63%**	**50.52%**	**49.19%**
Sub-Total: Distribution (based on TOU prices)			**39.23**			**43.41**	**4.18**	**10.65%**	**50.68%**	**49.35%**
Retail Transmission Rate – Network Service Rate	423	0.0068	2.87	427	0.0071	3.03	0.16	5.43%	3.54%	3.44%
Retail Transmission Rate – Line and Transformation Connection Service Rate	423	0.0036	1.52	427	0.006	2.56	1.04	68.29%	2.99%	2.91%
Sub-Total: Retail Transmission			**4.39**			**5.59**	**1.19**	**27.19%**	**6.53%**	**6.35%**
Sub-Total: Delivery (based on two-tier RPP prices)			**43.51**			**48.86**	**5.35**	**12.30%**	**57.05%**	**55.55%**
Sub-Total: Delivery (based on TOU prices)			**43.63**			**49.00**	**5.37**	**12.32%**	**57.21%**	**55.70%**
Wholesale Market Service Rate	423	0.0036	1.52	427	0.0036	1.54	0.01	0.98%	1.79%	1.75%
Rural Rate Protection Charge	423	0.0003	0.13	427	0.0003	0.13	0.00	0.98%	0.15%	0.15%
Ontario Electricity Support Program Charge	423	0.0000	0.00	427	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%	0.28%
Sub-Total: Regulatory			**1.90**			**1.91**	**0.02**	**0.85%**	**2.23%**	**2.18%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**76.21**			**81.58**	**5.37**	**7.04%**	**95.24%**	
HST		0.13	9.91		0.13	10.61	0.70	7.04%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**86.12**			**92.18**	**6.07**	**7.04%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.10		-0.08	-6.53	-0.43	-7.04%	-7.62%	
Total Amount on Two-Tier RPP			**80.02**			**85.66**	**5.64**	**7.04%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**78.39**			**83.78**	**5.39**	**6.88%**		**95.24%**
HST		0.13	10.19		0.13	10.89	0.70	6.88%		12.38%
Total Electricity Charge on TOU (including HST)			**88.58**			**94.67**	**6.09**	**6.88%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.27		-0.08	-6.70	-0.43	-6.88%		-7.62%
Total Amount on TOU			**82.31**			**87.97**	**5.66**	**6.88%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AR	NPDI_RES
Monthly Consumption (kWh)	570	570
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	608	602
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	570	0.077	43.89	570	0.077	43.89	0.00	0.00%	42.38%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**43.89**			**43.89**	**0.00**	**0.00%**	**42.38%**	
TOU-Off Peak	370	0.065	24.08	370	0.065	24.08	0.00	0.00%		22.54%
TOU-Mid Peak	97	0.095	9.21	97	0.095	9.21	0.00	0.00%		8.62%
TOU-On Peak	103	0.132	13.54	103	0.132	13.54	0.00	0.00%		12.67%
Sub-Total: Energy (TOU)			**46.83**			**46.83**	0.00	0.00%	**45.22%**	**43.83%**
Service Charge	1	36.78	36.78	1	40.43	40.43	3.65	9.92%	39.04%	37.84%
Fixed Acquisition Agreement Rider	1	-0.55	-0.55	1	0.00	0.00	0.55	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	570	0.0000	0.00	570	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	570	0.0009	0.51	570	0.0000	0.00	-0.51	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	570	0.0000	0.00	570	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.74**			**40.43**	**3.69**	**10.03%**	**39.04%**	**37.84%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.76%	0.74%
Line Losses on Cost of Power (based on two-tier RPP prices)	32	0.0770	2.48	38	0.0770	2.93	0.45	18.26%	2.83%	2.74%
Line Losses on Cost of Power (based on TOU prices)	32	0.0822	2.64	38	0.0822	3.12	0.48	18.26%	3.02%	2.92%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.01**			**44.15**	**4.14**	**10.35%**	**42.63%**	**41.32%**
Sub-Total: Distribution (based on TOU prices)			**40.17**			**44.34**	**4.17**	**10.38%**	**42.82%**	**41.50%**
Retail Transmission Rate – Network Service Rate	602	0.0068	4.09	608	0.0071	4.32	0.22	5.43%	4.17%	4.04%
Retail Transmission Rate – Line and Transformation Connection Service Rate	602	0.0036	2.17	608	0.006	3.65	1.48	68.29%	3.52%	3.41%
Sub-Total: Retail Transmission			**6.26**			**7.96**	**1.70**	**27.19%**	**7.69%**	**7.45%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.27**			**52.11**	**5.84**	**12.63%**	**50.32%**	**48.77%**
Sub-Total: Delivery (based on TOU prices)			**46.44**			**52.31**	**5.87**	**12.65%**	**50.51%**	**48.96%**
Wholesale Market Service Rate	602	0.0036	2.17	608	0.0036	2.19	0.02	0.98%	2.11%	2.05%
Rural Rate Protection Charge	602	0.0003	0.18	608	0.0003	0.18	0.00	0.98%	0.18%	0.17%
Ontario Electricity Support Program Charge	602	0.0000	0.00	608	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.24%	0.23%
Sub-Total: Regulatory			**2.60**			**2.62**	**0.02**	**0.88%**	**2.53%**	**2.45%**
Debt Retirement Charge (DRC)	570	0.0000	**0.00**	570	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**92.76**			**98.62**	**5.86**	**6.32%**	**95.24%**	
HST		0.13	12.06		0.13	12.82	0.76	6.32%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**104.82**			**111.44**	**6.63**	**6.32%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.42		-0.08	-7.89	-0.47	-6.32%	-7.62%	
Total Amount on Two-Tier RPP			**97.39**			**103.55**	**6.16**	**6.32%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**95.86**			**101.76**	**5.89**	**6.15%**		**95.24%**
HST		0.13	12.46		0.13	13.23	0.77	6.15%		12.38%
Total Electricity Charge on TOU (including HST)			**108.33**			**114.99**	**6.66**	**6.15%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-7.67		-0.08	-8.14	-0.47	-6.15%		-7.62%
Total Amount on TOU			**100.66**			**106.85**	**6.19**	**6.15%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AR	NPDI_RES
Monthly Consumption (kWh)	750	750
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	800	792
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	36.89%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.78%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**47.67%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		24.98%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.55%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.05%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.20%**	**48.58%**
Service Charge	1	36.78	36.78	1	40.43	40.43	3.65	9.92%	32.28%	31.87%
Fixed Acquisition Agreement Rider	1	-0.55	-0.55	1	0.00	0.00	0.55	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0000	0.00	750	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	750	0.0009	0.68	750	0.0000	0.00	-0.68	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.91**			**40.43**	**3.53**	**9.55%**	**32.28%**	**31.87%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.63%	0.62%
Line Losses on Cost of Power (based on two-tier RPP prices)	42	0.0900	3.81	50	0.0900	4.50	0.70	18.26%	3.60%	3.55%
Line Losses on Cost of Power (based on TOU prices)	42	0.0822	3.48	50	0.0822	4.11	0.63	18.26%	3.28%	3.24%
Sub-Total: Distribution (based on two-tier RPP prices)			**41.50**			**45.72**	**4.22**	**10.17%**	**36.51%**	**36.05%**
Sub-Total: Distribution (based on TOU prices)			**41.17**			**45.33**	**4.16**	**10.10%**	**36.20%**	**35.74%**
Retail Transmission Rate – Network Service Rate	792	0.0068	5.39	800	0.0071	5.68	0.29	5.43%	4.54%	4.48%
Retail Transmission Rate – Line and Transformation Connection Service Rate	792	0.0036	2.85	800	0.006	4.80	1.95	68.29%	3.83%	3.78%
Sub-Total: Retail Transmission			**8.24**			**10.48**	**2.24**	**27.19%**	**8.37%**	**8.26%**
Sub-Total: Delivery (based on two-tier RPP prices)			**49.74**			**56.20**	**6.46**	**12.99%**	**44.88%**	**44.31%**
Sub-Total: Delivery (based on TOU prices)			**49.41**			**55.81**	**6.40**	**12.95%**	**44.56%**	**44.00%**
Wholesale Market Service Rate	792	0.0036	2.85	800	0.0036	2.88	0.03	0.98%	2.30%	2.27%
Rural Rate Protection Charge	792	0.0003	0.24	800	0.0003	0.24	0.00	0.98%	0.19%	0.19%
Ontario Electricity Support Program Charge	792	0.0000	0.00	800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.34**			**3.37**	**0.03**	**0.90%**	**2.69%**	**2.66%**
Debt Retirement Charge (DRC)	750	0.0000	**0.00**	750	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**112.78**			**119.27**	**6.49**	**5.76%**	**95.24%**	
HST		0.13	14.66		0.13	15.51	0.84	5.76%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**127.44**			**134.78**	**7.33**	**5.76%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.02		-0.08	-9.54	-0.52	-5.76%	-7.62%	
Total Amount on Two-Tier RPP			**118.42**			**125.24**	**6.82**	**5.76%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**114.37**			**120.80**	**6.43**	**5.62%**		**95.24%**
HST		0.13	14.87		0.13	15.70	0.84	5.62%		12.38%
Total Electricity Charge on TOU (including HST)			**129.24**			**136.50**	**7.27**	**5.62%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.15		-0.08	-9.66	-0.51	-5.62%		-7.62%
Total Amount on TOU			**120.09**			**126.84**	**6.75**	**5.62%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AR	NPDI_RES
Monthly Consumption (kWh)	1800	1800
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	1920	1902
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.40%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.02%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.42%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.24%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		11.94%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.57%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**58.90%**	**60.75%**
Service Charge	1	36.78	36.78	1	40.43	40.43	3.65	9.92%	16.10%	16.61%
Fixed Acquisition Agreement Rider	1	-0.55	-0.55	1	0.00	0.00	0.55	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	1,800	0.0009	1.62	1,800	0.0000	0.00	-1.62	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**37.85**			**40.43**	**2.58**	**6.82%**	**16.10%**	**16.61%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.31%	0.32%
Line Losses on Cost of Power (based on two-tier RPP prices)	102	0.0900	9.14	120	0.0900	10.81	1.67	18.26%	4.30%	4.44%
Line Losses on Cost of Power (based on TOU prices)	102	0.0822	8.34	120	0.0822	9.86	1.52	18.26%	3.93%	4.05%
Sub-Total: Distribution (based on two-tier RPP prices)			**47.78**			**52.03**	**4.25**	**8.89%**	**20.72%**	**21.37%**
Sub-Total: Distribution (based on TOU prices)			**46.98**			**51.08**	**4.10**	**8.73%**	**20.35%**	**20.98%**
Retail Transmission Rate – Network Service Rate	1,902	0.0068	12.93	1,920	0.0071	13.63	0.70	5.43%	5.43%	5.60%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,902	0.0036	6.85	1,920	0.006	11.52	4.67	68.29%	4.59%	4.73%
Sub-Total: Retail Transmission			**19.78**			**25.15**	**5.38**	**27.19%**	**10.02%**	**10.33%**
Sub-Total: Delivery (based on two-tier RPP prices)			**67.55**			**77.18**	**9.63**	**14.25%**	**30.74%**	**31.70%**
Sub-Total: Delivery (based on TOU prices)			**66.76**			**76.24**	**9.48**	**14.20%**	**30.36%**	**31.31%**
Wholesale Market Service Rate	1,902	0.0036	6.85	1,920	0.0036	6.91	0.07	0.98%	2.75%	2.84%
Rural Rate Protection Charge	1,902	0.0003	0.57	1,920	0.0003	0.58	0.01	0.98%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,902	0.0000	0.00	1,920	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.67**			**7.74**	**0.07**	**0.94%**	**3.08%**	**3.18%**
Debt Retirement Charge (DRC)	1,800	0.0000	**0.00**	1,800	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**229.42**			**239.12**	**9.70**	**4.23%**	**95.24%**	
HST		0.13	29.82		0.13	31.09	1.26	4.23%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**259.24**			**270.20**	**10.96**	**4.23%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.35		-0.08	-19.13	-0.78	-4.23%	-7.62%	
Total Amount on Two-Tier RPP			**240.89**			**251.07**	**10.18**	**4.23%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**222.31**			**231.86**	**9.55**	**4.30%**		**95.24%**
HST		0.13	28.90		0.13	30.14	1.24	4.30%		12.38%
Total Electricity Charge on TOU (including HST)			**251.21**			**262.01**	**10.79**	**4.30%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-17.78		-0.08	-18.55	-0.76	-4.30%		-7.62%
Total Amount on TOU			**233.43**			**243.46**	**10.03**	**4.30%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AR	HCHI_RES
Monthly Consumption (kWh)	400	400
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	426.68	426.2
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	35.96%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**35.96%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		19.21%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.34%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		10.80%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**38.37%**	**37.36%**
Service Charge	1	35.62	35.62	1	40.43	40.43	4.81	13.50%	47.20%	45.96%
Fixed Acquisition Agreement Rider	1	-0.36	-0.36	1	0.00	0.00	0.36	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0000	0.00	400	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	400	0.0004	0.16	400	0.0000	0.00	-0.16	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	400	0.0000	0.00	400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**35.42**			**40.43**	**5.01**	**14.14%**	**47.20%**	**45.96%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.92%	0.90%
Line Losses on Cost of Power (based on two-tier RPP prices)	26	0.0770	2.02	27	0.0770	2.05	0.04	1.83%	2.40%	2.34%
Line Losses on Cost of Power (based on TOU prices)	26	0.0822	2.15	27	0.0822	2.19	0.04	1.83%	2.56%	2.49%
Sub-Total: Distribution (based on two-tier RPP prices)			**38.23**			**43.27**	**5.05**	**13.20%**	**50.52%**	**49.19%**
Sub-Total: Distribution (based on TOU prices)			**38.36**			**43.41**	**5.05**	**13.16%**	**50.68%**	**49.35%**
Retail Transmission Rate – Network Service Rate	426	0.0065	2.79	427	0.0071	3.03	0.24	8.61%	3.54%	3.44%
Retail Transmission Rate – Line and Transformation Connection Service Rate	426	0.0054	2.31	427	0.006	2.56	0.25	10.91%	2.99%	2.91%
Sub-Total: Retail Transmission			**5.10**			**5.59**	**0.49**	**9.65%**	**6.53%**	**6.35%**
Sub-Total: Delivery (based on two-tier RPP prices)			**43.32**			**48.86**	**5.54**	**12.78%**	**57.05%**	**55.55%**
Sub-Total: Delivery (based on TOU prices)			**43.46**			**49.00**	**5.54**	**12.75%**	**57.21%**	**55.70%**
Wholesale Market Service Rate	426	0.0036	1.53	427	0.0036	1.54	0.00	0.11%	1.79%	1.75%
Rural Rate Protection Charge	426	0.0003	0.13	427	0.0003	0.13	0.00	0.11%	0.15%	0.15%
Ontario Electricity Support Program Charge	426	0.0000	0.00	427	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%	0.28%
Sub-Total: Regulatory			**1.91**			**1.91**	**0.00**	**0.10%**	**2.23%**	**2.18%**
Debt Retirement Charge (DRC)	400	0.0000	**0.00**	400	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**76.04**			**81.58**	**5.54**	**7.29%**	**95.24%**	
HST		0.13	9.88		0.13	10.61	0.72	7.29%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**85.92**			**92.18**	**6.26**	**7.29%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.08		-0.08	-6.53	-0.44	-7.29%	-7.62%	
Total Amount on Two-Tier RPP			**79.84**			**85.66**	**5.82**	**7.29%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**78.24**			**83.78**	**5.54**	**7.09%**		**95.24%**
HST		0.13	10.17		0.13	10.89	0.72	7.09%		12.38%
Total Electricity Charge on TOU (including HST)			**88.41**			**94.67**	**6.26**	**7.09%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.26		-0.08	-6.70	-0.44	-7.09%		-7.62%
Total Amount on TOU			**82.15**			**87.97**	**5.82**	**7.09%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AR	HCHI_RES
Monthly Consumption (kWh)	694	694
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	740	740
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	38.98%	
Energy Second Tier (kWh)	94	0.090	8.46	94	0.090	8.46	0.00	0.00%	7.14%	
Sub-Total: Energy (RPP)			**54.66**			**54.66**	**0.00**	**0.00%**	**46.12%**	
TOU-Off Peak	451	0.065	29.32	451	0.065	29.32	0.00	0.00%		24.31%
TOU-Mid Peak	118	0.095	11.21	118	0.095	11.21	0.00	0.00%		9.29%
TOU-On Peak	125	0.132	16.49	125	0.132	16.49	0.00	0.00%		13.67%
Sub-Total: Energy (TOU)			**57.02**			**57.02**	0.00	0.00%	**48.11%**	**47.27%**
Service Charge	1	35.62	35.62	1	40.43	40.43	4.81	13.50%	34.11%	33.52%
Fixed Acquisition Agreement Rider	1	-0.36	-0.36	1	0.00	0.00	0.36	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	694	0.0000	0.00	694	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	694	0.0004	0.28	694	0.0000	0.00	-0.28	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	694	0.0000	0.00	694	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**35.54**			**40.43**	**4.89**	**13.77%**	**34.11%**	**33.52%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.67%	0.65%
Line Losses on Cost of Power (based on two-tier RPP prices)	45	0.0900	4.09	46	0.0900	4.17	0.07	1.83%	3.52%	3.45%
Line Losses on Cost of Power (based on TOU prices)	45	0.0822	3.74	46	0.0822	3.80	0.07	1.83%	3.21%	3.15%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.42**			**45.39**	**4.97**	**12.29%**	**38.29%**	**37.63%**
Sub-Total: Distribution (based on TOU prices)			**40.06**			**45.02**	**4.96**	**12.38%**	**37.98%**	**37.32%**
Retail Transmission Rate – Network Service Rate	740	0.0065	4.84	740	0.0071	5.26	0.42	8.61%	4.43%	4.36%
Retail Transmission Rate – Line and Transformation Connection Service Rate	740	0.0054	4.00	740	0.006	4.44	0.44	10.91%	3.75%	3.68%
Sub-Total: Retail Transmission			**8.84**			**9.70**	**0.85**	**9.65%**	**8.18%**	**8.04%**
Sub-Total: Delivery (based on two-tier RPP prices)			**49.26**			**55.08**	**5.82**	**11.82%**	**46.47%**	**45.67%**
Sub-Total: Delivery (based on TOU prices)			**48.91**			**54.72**	**5.81**	**11.89%**	**46.17%**	**45.36%**
Wholesale Market Service Rate	740	0.0036	2.66	740	0.0036	2.67	0.00	0.11%	2.25%	2.21%
Rural Rate Protection Charge	740	0.0003	0.22	740	0.0003	0.22	0.00	0.11%	0.19%	0.18%
Ontario Electricity Support Program Charge	740	0.0000	0.00	740	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**3.13**			**3.14**	**0.00**	**0.10%**	**2.65%**	**2.60%**
Debt Retirement Charge (DRC)	694	0.0000	**0.00**	694	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**107.06**			**112.89**	**5.82**	**5.44%**	**95.24%**	
HST		0.13	13.92		0.13	14.68	0.76	5.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**120.98**			**127.56**	**6.58**	**5.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.56		-0.08	-9.03	-0.47	-5.44%	-7.62%	
Total Amount on Two-Tier RPP			**112.42**			**118.53**	**6.12**	**5.44%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**109.06**			**114.88**	**5.82**	**5.33%**		**95.24%**
HST		0.13	14.18		0.13	14.93	0.76	5.33%		12.38%
Total Electricity Charge on TOU (including HST)			**123.24**			**129.82**	**6.57**	**5.33%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.73		-0.08	-9.19	-0.47	-5.33%		-7.62%
Total Amount on TOU			**114.52**			**120.63**	**6.11**	**5.33%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AR	HCHI_RES
Monthly Consumption (kWh)	750	750
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	800.025	799.125
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	36.89%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.78%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**47.67%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		24.98%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.55%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.05%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.20%**	**48.58%**
Service Charge	1	35.62	35.62	1	40.43	40.43	4.81	13.50%	32.28%	31.87%
Fixed Acquisition Agreement Rider	1	-0.36	-0.36	1	0.00	0.00	0.36	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0000	0.00	750	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	750	0.0004	0.30	750	0.0000	0.00	-0.30	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**35.56**			**40.43**	**4.87**	**13.70%**	**32.28%**	**31.87%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.63%	0.62%
Line Losses on Cost of Power (based on two-tier RPP prices)	49	0.0900	4.42	50	0.0900	4.50	0.08	1.83%	3.60%	3.55%
Line Losses on Cost of Power (based on TOU prices)	49	0.0822	4.04	50	0.0822	4.11	0.07	1.83%	3.28%	3.24%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.77**			**45.72**	**4.95**	**12.14%**	**36.51%**	**36.05%**
Sub-Total: Distribution (based on TOU prices)			**40.39**			**45.33**	**4.94**	**12.24%**	**36.20%**	**35.74%**
Retail Transmission Rate – Network Service Rate	799	0.0065	5.23	800	0.0071	5.68	0.45	8.61%	4.54%	4.48%
Retail Transmission Rate – Line and Transformation Connection Service Rate	799	0.0054	4.33	800	0.006	4.80	0.47	10.91%	3.83%	3.78%
Sub-Total: Retail Transmission			**9.56**			**10.48**	**0.92**	**9.65%**	**8.37%**	**8.26%**
Sub-Total: Delivery (based on two-tier RPP prices)			**50.33**			**56.20**	**5.87**	**11.67%**	**44.88%**	**44.31%**
Sub-Total: Delivery (based on TOU prices)			**49.94**			**55.81**	**5.87**	**11.75%**	**44.56%**	**44.00%**
Wholesale Market Service Rate	799	0.0036	2.88	800	0.0036	2.88	0.00	0.11%	2.30%	2.27%
Rural Rate Protection Charge	799	0.0003	0.24	800	0.0003	0.24	0.00	0.11%	0.19%	0.19%
Ontario Electricity Support Program Charge	799	0.0000	0.00	800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.37**			**3.37**	**0.00**	**0.10%**	**2.69%**	**2.66%**
Debt Retirement Charge (DRC)	750	0.0000	**0.00**	750	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**113.40**			**119.27**	**5.88**	**5.18%**	**95.24%**	
HST		0.13	14.74		0.13	15.51	0.76	5.18%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**128.14**			**134.78**	**6.64**	**5.18%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.07		-0.08	-9.54	-0.47	-5.18%	-7.62%	
Total Amount on Two-Tier RPP			**119.07**			**125.24**	**6.17**	**5.18%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**114.93**			**120.80**	**5.87**	**5.11%**		**95.24%**
HST		0.13	14.94		0.13	15.70	0.76	5.11%		12.38%
Total Electricity Charge on TOU (including HST)			**129.87**			**136.50**	**6.63**	**5.11%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.19		-0.08	-9.66	-0.47	-5.11%		-7.62%
Total Amount on TOU			**120.68**			**126.84**	**6.16**	**5.11%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AR	HCHI_RES
Monthly Consumption (kWh)	1800	1800
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	600	600
Monthly Consumption (kWh) - Uplifted	1920.06	1917.9
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.40%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.02%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.42%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.24%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		11.94%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.57%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**58.90%**	**60.75%**
Service Charge	1	35.62	35.62	1	40.43	40.43	4.81	13.50%	16.10%	16.61%
Fixed Acquisition Agreement Rider	1	-0.36	-0.36	1	0.00	0.00	0.36	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	0.00%	0.00%	0.00%
Low Voltage Service Rate	1,800	0.0004	0.72	1,800	0.0000	0.00	-0.72	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**35.98**			**40.43**	**4.45**	**12.37%**	**16.10%**	**16.61%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.31%	0.32%
Line Losses on Cost of Power (based on two-tier RPP prices)	118	0.0900	10.61	120	0.0900	10.81	0.19	1.83%	4.30%	4.44%
Line Losses on Cost of Power (based on TOU prices)	118	0.0822	9.69	120	0.0822	9.86	0.18	1.83%	3.93%	4.05%
Sub-Total: Distribution (based on two-tier RPP prices)			**47.38**			**52.03**	**4.64**	**9.80%**	**20.72%**	**21.37%**
Sub-Total: Distribution (based on TOU prices)			**46.46**			**51.08**	**4.63**	**9.96%**	**20.35%**	**20.98%**
Retail Transmission Rate – Network Service Rate	1,918	0.0065	12.55	1,920	0.0071	13.63	1.08	8.61%	5.43%	5.60%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,918	0.0054	10.39	1,920	0.006	11.52	1.13	10.91%	4.59%	4.73%
Sub-Total: Retail Transmission			**22.94**			**25.15**	**2.21**	**9.65%**	**10.02%**	**10.33%**
Sub-Total: Delivery (based on two-tier RPP prices)			**70.32**			**77.18**	**6.86**	**9.75%**	**30.74%**	**31.70%**
Sub-Total: Delivery (based on TOU prices)			**69.40**			**76.24**	**6.84**	**9.86%**	**30.36%**	**31.31%**
Wholesale Market Service Rate	1,918	0.0036	6.90	1,920	0.0036	6.91	0.01	0.11%	2.75%	2.84%
Rural Rate Protection Charge	1,918	0.0003	0.58	1,920	0.0003	0.58	0.00	0.11%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,918	0.0000	0.00	1,920	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.73**			**7.74**	**0.01**	**0.11%**	**3.08%**	**3.18%**
Debt Retirement Charge (DRC)	1,800	0.0000	**0.00**	1,800	0.0000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**232.25**			**239.12**	**6.87**	**2.96%**	**95.24%**	
HST		0.13	30.19		0.13	31.09	0.89	2.96%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**262.44**			**270.20**	**7.76**	**2.96%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.58		-0.08	-19.13	-0.55	-2.96%	-7.62%	
Total Amount on Two-Tier RPP			**243.86**			**251.07**	**7.21**	**2.96%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**225.01**			**231.86**	**6.85**	**3.04%**		**95.24%**
HST		0.13	29.25		0.13	30.14	0.89	3.04%		12.38%
Total Electricity Charge on TOU (including HST)			**254.26**			**262.01**	**7.74**	**3.04%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.00		-0.08	-18.55	-0.55	-3.04%		-7.62%
Total Amount on TOU			**236.26**			**243.46**	**7.19**	**3.04%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AGSe	NPDI_GS<50
Monthly Consumption (kWh)	1000	1000
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1066.7	1056.4
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	32.64%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.72%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**45.35%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		23.68%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.05%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.32%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**46.43%**	**46.05%**
Service Charge	1	49.98	49.98	1	40.92	40.92	-9.06	-18.13%	23.13%	22.94%
Fixed Acquisition Agreement Rider	1	-0.74	-0.74	1	0.00	0.00	0.74	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0156	15.60	1,000	0.0188	18.80	3.20	20.51%	10.62%	10.54%
Low Voltage Service Rate	1,000	0.0008	0.80	1,000	0.0000	0.00	-0.80	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	1,000	-0.0003	-0.30	1,000	0.0000	0.00	0.30	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**65.34**			**59.72**	**-5.62**	**-8.60%**	**33.75%**	**33.47%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.45%	0.44%
Line Losses on Cost of Power (based on two-tier RPP prices)	56	0.0900	5.08	67	0.0900	6.00	0.93	18.26%	3.39%	3.36%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.48	67	0.0822	5.48	0.00	0.00%	3.10%	3.07%
Sub-Total: Distribution (based on two-tier RPP prices)			**71.21**			**66.51**	**-4.69**	**-6.59%**	**37.59%**	**37.28%**
Sub-Total: Distribution (based on TOU prices)			**71.61**			**65.99**	**-5.62**	**-7.85%**	**37.29%**	**36.99%**
Retail Transmission Rate – Network Service Rate	1,056	0.0063	6.66	1,067	0.0053	5.65	-1.00	-15.05%	3.20%	3.17%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,056	0.0031	3.27	1,067	0.0044	4.69	1.42	43.32%	2.65%	2.63%
Sub-Total: Retail Transmission			**9.93**			**10.35**	**0.42**	**4.20%**	**5.85%**	**5.80%**
Sub-Total: Delivery (based on two-tier RPP prices)			**81.14**			**76.86**	**-4.28**	**-5.27%**	**43.44%**	**43.08%**
Sub-Total: Delivery (based on TOU prices)			**81.54**			**76.34**	**-5.20**	**-6.38%**	**43.14%**	**42.79%**
Wholesale Market Service Rate	1,056	0.0036	3.80	1,067	0.0036	3.84	0.04	0.98%	2.17%	2.15%
Rural Rate Protection Charge	1,056	0.0003	0.32	1,067	0.0003	0.32	0.00	0.98%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,056	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.37**			**4.41**	**0.04**	**0.92%**	**2.49%**	**2.47%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.96%**	**3.92%**
Total Electricty Charge on Two-Tier RPP			**172.76**			**168.52**	**-4.24**	**-2.45%**	**95.24%**	
HST		0.13	22.46		0.13	21.91	-0.55	-2.45%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**195.21**			**190.43**	**-4.79**	**-2.45%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.82		-0.08	-13.48	0.34	2.45%	-7.62%	
Total Amount on Two-Tier RPP			**181.39**			**176.95**	**-4.45**	**-2.45%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**175.07**			**169.91**	**-5.16**	**-2.95%**		**95.24%**
HST		0.13	22.76		0.13	22.09	-0.67	-2.95%		12.38%
Total Electricity Charge on TOU (including HST)			**197.83**			**192.00**	**-5.83**	**-2.95%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.01		-0.08	-13.59	0.41	2.95%		-7.62%
Total Amount on TOU			**183.82**			**178.40**	**-5.42**	**-2.95%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AGSe	NPDI_GS<50
Monthly Consumption (kWh)	2,182	2,182
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	2328	2306
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	16.68%	
Energy Second Tier (kWh)	1,432	0.090	128.92	1,432	0.090	128.92	0.00	0.00%	37.24%	
Sub-Total: Energy (RPP)			**186.67**			**186.67**	**0.00**	**0.00%**	**53.92%**	
TOU-Off Peak	1,419	0.065	92.21	1,419	0.065	92.21	0.00	0.00%		27.34%
TOU-Mid Peak	371	0.095	35.25	371	0.095	35.25	0.00	0.00%		10.45%
TOU-On Peak	393	0.132	51.86	393	0.132	51.86	0.00	0.00%		15.38%
Sub-Total: Energy (TOU)			**179.31**			**179.31**	0.00	0.00%	**51.80%**	**53.17%**
Service Charge	1	49.98	49.98	1	40.92	40.92	-9.06	-18.13%	11.82%	12.13%
Fixed Acquisition Agreement Rider	1	-0.74	-0.74	1	0.00	0.00	0.74	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	2,182	0.0156	34.05	2,182	0.0188	41.03	6.98	20.51%	11.85%	12.17%
Low Voltage Service Rate	2,182	0.0008	1.75	2,182	0.0000	0.00	-1.75	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	2,182	-0.0003	-0.65	2,182	0.0000	0.00	0.65	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**84.38**			**81.95**	**-2.43**	**-2.88%**	**23.67%**	**24.30%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.23%	0.23%
Line Losses on Cost of Power (based on two-tier RPP prices)	123	0.0900	11.08	146	0.0900	13.10	2.02	18.26%	3.78%	3.88%
Line Losses on Cost of Power (based on TOU prices)	123	0.0822	10.11	146	0.0822	11.96	1.85	18.26%	3.45%	3.55%
Sub-Total: Distribution (based on two-tier RPP prices)			**96.25**			**95.84**	**-0.40**	**-0.42%**	**27.68%**	**28.42%**
Sub-Total: Distribution (based on TOU prices)			**95.28**			**94.70**	**-0.58**	**-0.61%**	**27.36%**	**28.08%**
Retail Transmission Rate – Network Service Rate	2,306	0.0063	14.53	2,328	0.0053	12.34	-2.19	-15.05%	3.56%	3.66%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,306	0.0031	7.15	2,328	0.0044	10.24	3.10	43.32%	2.96%	3.04%
Sub-Total: Retail Transmission			**21.67**			**22.58**	**0.91**	**4.20%**	**6.52%**	**6.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**117.92**			**118.42**	**0.51**	**0.43%**	**34.21%**	**35.11%**
Sub-Total: Delivery (based on TOU prices)			**116.95**			**117.28**	**0.33**	**0.28%**	**33.88%**	**34.77%**
Wholesale Market Service Rate	2,306	0.0036	8.30	2,328	0.0036	8.38	0.08	0.98%	2.42%	2.49%
Rural Rate Protection Charge	2,306	0.0003	0.69	2,328	0.0003	0.70	0.01	0.98%	0.20%	0.21%
Ontario Electricity Support Program Charge	2,306	0.0000	0.00	2,328	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%	0.07%
Sub-Total: Regulatory			**9.24**			**9.33**	**0.09**	**0.95%**	**2.69%**	**2.77%**
Debt Retirement Charge (DRC)	2,182	0.007	**15.28**	2,182	0.007	**15.28**	**0.00**	**0.00%**	**4.41%**	**4.53%**
Total Electricty Charge on Two-Tier RPP			**329.11**			**329.70**	**0.59**	**0.18%**	**95.24%**	
HST		0.13	42.78		0.13	42.86	0.08	0.18%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**371.89**			**372.56**	**0.67**	**0.18%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-26.33		-0.08	-26.38	-0.05	-0.18%	-7.62%	
Total Amount on Two-Tier RPP			**345.57**			**346.19**	**0.62**	**0.18%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**320.78**			**321.20**	**0.42**	**0.13%**		**95.24%**
HST		0.13	41.70		0.13	41.76	0.05	0.13%		12.38%
Total Electricity Charge on TOU (including HST)			**362.49**			**362.96**	**0.47**	**0.13%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-25.66		-0.08	-25.70	-0.03	-0.13%		-7.62%
Total Amount on TOU			**336.82**			**337.26**	**0.44**	**0.13%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AGSe	NPDI_GS<50
Monthly Consumption (kWh)	2,000	2,000
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	2133.4	2112.8
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	18.04%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	35.15%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**53.19%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		27.02%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.33%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		15.19%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**51.34%**	**52.54%**
Service Charge	1	49.98	49.98	1	40.92	40.92	-9.06	-18.13%	12.78%	13.08%
Fixed Acquisition Agreement Rider	1	-0.74	-0.74	1	0.00	0.00	0.74	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0156	31.20	2,000	0.0188	37.60	6.40	20.51%	11.75%	12.02%
Low Voltage Service Rate	2,000	0.0008	1.60	2,000	0.0000	0.00	-1.60	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	2,000	-0.0003	-0.60	2,000	0.0000	0.00	0.60	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**81.44**			**78.52**	**-2.92**	**-3.59%**	**24.53%**	**25.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	113	0.0900	10.15	133	0.0900	12.01	1.85	18.26%	3.75%	3.84%
Line Losses on Cost of Power (based on TOU prices)	113	0.0822	9.27	133	0.0822	10.96	1.69	18.26%	3.42%	3.50%
Sub-Total: Distribution (based on two-tier RPP prices)			**92.38**			**91.32**	**-1.07**	**-1.15%**	**28.53%**	**29.20%**
Sub-Total: Distribution (based on TOU prices)			**91.50**			**90.27**	**-1.23**	**-1.34%**	**28.20%**	**28.86%**
Retail Transmission Rate – Network Service Rate	2,113	0.0063	13.31	2,133	0.0053	11.31	-2.00	-15.05%	3.53%	3.62%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,113	0.0031	6.55	2,133	0.0044	9.39	2.84	43.32%	2.93%	3.00%
Sub-Total: Retail Transmission			**19.86**			**20.69**	**0.83**	**4.20%**	**6.47%**	**6.62%**
Sub-Total: Delivery (based on two-tier RPP prices)			**112.24**			**112.01**	**-0.23**	**-0.21%**	**35.00%**	**35.81%**
Sub-Total: Delivery (based on TOU prices)			**111.36**			**110.96**	**-0.39**	**-0.35%**	**34.67%**	**35.48%**
Wholesale Market Service Rate	2,113	0.0036	7.61	2,133	0.0036	7.68	0.07	0.98%	2.40%	2.46%
Rural Rate Protection Charge	2,113	0.0003	0.63	2,133	0.0003	0.64	0.01	0.98%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,113	0.0000	0.00	2,133	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.49**			**8.57**	**0.08**	**0.95%**	**2.68%**	**2.74%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.37%**	**4.48%**
Total Electricty Charge on Two-Tier RPP			**304.98**			**304.83**	**-0.15**	**-0.05%**	**95.24%**	
HST		0.13	39.65		0.13	39.63	-0.02	-0.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**344.63**			**344.46**	**-0.17**	**-0.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.40		-0.08	-24.39	0.01	0.05%	-7.62%	
Total Amount on Two-Tier RPP			**320.23**			**320.07**	**-0.16**	**-0.05%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**298.17**			**297.85**	**-0.31**	**-0.11%**		**95.24%**
HST		0.13	38.76		0.13	38.72	-0.04	-0.11%		12.38%
Total Electricity Charge on TOU (including HST)			**336.93**			**336.58**	**-0.35**	**-0.11%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.85		-0.08	-23.83	0.03	0.11%		-7.62%
Total Amount on TOU			**313.08**			**312.75**	**-0.33**	**-0.11%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AGSe	NPDI_GS<50
Monthly Consumption (kWh)	15,000	15,000
Peak (kW)	0	0
Loss factor	1.0667	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	16000.5	15846
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.65%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	58.81%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**61.46%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		30.78%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.76%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		17.31%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**56.51%**	**59.85%**
Service Charge	1	49.98	49.98	1	40.92	40.92	-9.06	-18.13%	1.88%	1.99%
Fixed Acquisition Agreement Rider	1	-0.74	-0.74	1	0.00	0.00	0.74	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0156	234.00	15,000	0.0188	282.00	48.00	20.51%	12.93%	13.69%
Low Voltage Service Rate	15,000	0.0008	12.00	15,000	0.0000	0.00	-12.00	-100.00%	0.00%	0.00%
Volumetric Acquisition Agreement Rider	15,000	-0.0003	-4.50	15,000	0.0000	0.00	4.50	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**290.74**			**322.92**	**32.18**	**11.07%**	**14.81%**	**15.68%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.04%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	846	0.0900	76.14	1,001	0.0900	90.05	13.91	18.26%	4.13%	4.37%
Line Losses on Cost of Power (based on TOU prices)	846	0.0822	69.51	1,001	0.0822	82.20	12.69	18.26%	3.77%	3.99%
Sub-Total: Distribution (based on two-tier RPP prices)			**367.67**			**413.76**	**46.09**	**12.53%**	**18.97%**	**20.09%**
Sub-Total: Distribution (based on TOU prices)			**361.04**			**405.91**	**44.87**	**12.43%**	**18.61%**	**19.71%**
Retail Transmission Rate – Network Service Rate	15,846	0.0063	99.83	16,001	0.0053	84.80	-15.03	-15.05%	3.89%	4.12%
Retail Transmission Rate – Line and Transformation Connection Service Rate	15,846	0.0031	49.12	16,001	0.0044	70.40	21.28	43.32%	3.23%	3.42%
Sub-Total: Retail Transmission			**148.95**			**155.20**	**6.25**	**4.20%**	**7.12%**	**7.54%**
Sub-Total: Delivery (based on two-tier RPP prices)			**516.62**			**568.96**	**52.34**	**10.13%**	**26.09%**	**27.63%**
Sub-Total: Delivery (based on TOU prices)			**509.99**			**561.12**	**51.13**	**10.02%**	**25.73%**	**27.25%**
Wholesale Market Service Rate	15,846	0.0036	57.05	16,001	0.0036	57.60	0.56	0.98%	2.64%	2.80%
Rural Rate Protection Charge	15,846	0.0003	4.75	16,001	0.0003	4.80	0.05	0.98%	0.22%	0.23%
Ontario Electricity Support Program Charge	15,846	0.0000	0.00	16,001	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.05**			**62.65**	**0.60**	**0.97%**	**2.87%**	**3.04%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.81%**	**5.10%**
Total Electricty Charge on Two-Tier RPP			**2,023.92**			**2,076.86**	**52.94**	**2.62%**	**95.24%**	
HST		0.13	263.11		0.13	269.99	6.88	2.62%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,287.03**			**2,346.85**	**59.82**	**2.62%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-161.91		-0.08	-166.15	-4.24	-2.62%	-7.62%	
Total Amount on Two-Tier RPP			**2,125.12**			**2,180.70**	**55.59**	**2.62%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**1,909.44**			**1,961.17**	**51.73**	**2.71%**		**95.24%**
HST		0.13	248.23		0.13	254.95	6.72	2.71%		12.38%
Total Electricity Charge on TOU (including HST)			**2,157.67**			**2,216.12**	**58.45**	**2.71%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-152.76		-0.08	-156.89	-4.14	-2.71%		-7.62%
Total Amount on TOU			**2,004.91**			**2,059.23**	**54.32**	**2.71%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AGSe	HCHI_GS<50
Monthly Consumption (kWh)	1000	1000
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1066.7	1065.5
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	32.64%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.72%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**45.35%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		23.68%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.05%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.32%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**46.43%**	**46.05%**
Service Charge	1	26.94	26.94	1	40.92	40.92	13.98	51.89%	23.13%	22.94%
Fixed Acquisition Agreement Rider	1	-0.27	-0.27	1	0.00	0.00	0.27	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0190	19.00	1,000	0.0188	18.80	-0.20	-1.05%	10.62%	10.54%
Low Voltage Service Rate	1,000	0.0004	0.40	1,000	0.0000	0.00	-0.40	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,000	-0.0002	-0.20	1,000	0.0000	0.00	0.20	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**45.87**			**59.72**	**13.85**	**30.19%**	**33.75%**	**33.47%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.45%	0.44%
Line Losses on Cost of Power (based on two-tier RPP prices)	66	0.0900	5.90	67	0.0900	6.00	0.11	1.83%	3.39%	3.36%
Line Losses on Cost of Power (based on TOU prices)	66	0.0822	5.38	67	0.0822	5.48	0.10	1.83%	3.10%	3.07%
Sub-Total: Distribution (based on two-tier RPP prices)			**52.56**			**66.51**	**13.96**	**26.56%**	**37.59%**	**37.28%**
Sub-Total: Distribution (based on TOU prices)			**52.04**			**65.99**	**13.95**	**26.80%**	**37.29%**	**36.99%**
Retail Transmission Rate – Network Service Rate	1,066	0.0059	6.26	1,067	0.0053	5.65	-0.60	-9.62%	3.20%	3.17%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,066	0.0050	5.33	1,067	0.0044	4.69	-0.63	-11.89%	2.65%	2.63%
Sub-Total: Retail Transmission			**11.58**			**10.35**	**-1.23**	**-10.66%**	**5.85%**	**5.80%**
Sub-Total: Delivery (based on two-tier RPP prices)			**64.14**			**76.86**	**12.72**	**19.84%**	**43.44%**	**43.08%**
Sub-Total: Delivery (based on TOU prices)			**63.62**			**76.34**	**12.71**	**19.98%**	**43.14%**	**42.79%**
Wholesale Market Service Rate	1,066	0.0036	3.84	1,067	0.0036	3.84	0.00	0.11%	2.17%	2.15%
Rural Rate Protection Charge	1,066	0.0003	0.32	1,067	0.0003	0.32	0.00	0.11%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,066	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.11%**	**2.49%**	**2.47%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.96%**	**3.92%**
Total Electricty Charge on Two-Tier RPP			**155.79**			**168.52**	**12.73**	**8.17%**	**95.24%**	
HST		0.13	20.25		0.13	21.91	1.65	8.17%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**176.05**			**190.43**	**14.38**	**8.17%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.46		-0.08	-13.48	-1.02	-8.17%	-7.62%	
Total Amount on Two-Tier RPP			**163.58**			**176.95**	**13.36**	**8.17%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**157.19**			**169.91**	**12.72**	**8.09%**		**95.24%**
HST		0.13	20.43		0.13	22.09	1.65	8.09%		12.38%
Total Electricity Charge on TOU (including HST)			**177.62**			**192.00**	**14.37**	**8.09%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.58		-0.08	-13.59	-1.02	-8.09%		-7.62%
Total Amount on TOU			**165.05**			**178.40**	**13.35**	**8.09%**		**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AGSe	HCHI_GS<50
Monthly Consumption (kWh)	1,819	1,819
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1,941	1,939
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	19.63%	
Energy Second Tier (kWh)	1,069	0.090	96.25	1,069	0.090	96.25	0.00	0.00%	32.71%	
Sub-Total: Energy (RPP)			**154.00**			**154.00**	**0.00**	**0.00%**	**52.34%**	
TOU-Off Peak	1,183	0.065	76.87	1,183	0.065	76.87	0.00	0.00%		26.65%
TOU-Mid Peak	309	0.095	29.38	309	0.095	29.38	0.00	0.00%		10.19%
TOU-On Peak	327	0.132	43.23	327	0.132	43.23	0.00	0.00%		14.98%
Sub-Total: Energy (TOU)			**149.49**			**149.49**	**0.00**	**0.00%**	**50.81%**	**51.82%**
Service Charge	1	26.94	26.94	1	40.92	40.92	13.98	51.89%	13.91%	14.18%
Fixed Acquisition Agreement Rider	1	-0.27	-0.27	1	0.00	0.00	0.27	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	1,819	0.0190	34.57	1,819	0.0188	34.21	-0.36	-1.05%	11.63%	11.86%
Low Voltage Service Rate	1,819	0.0004	0.73	1,819	0.0000	0.00	-0.73	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,819	-0.0002	-0.36	1,819	0.0000	0.00	0.36	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**61.60**			**75.13**	**13.52**	**21.95%**	**25.53%**	**26.04%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.27%	0.27%
Line Losses on Cost of Power (based on two-tier RPP prices)	119	0.0900	10.73	121	0.0900	10.92	0.20	1.83%	3.71%	3.79%
Line Losses on Cost of Power (based on TOU prices)	119	0.0822	9.79	121	0.0822	9.97	0.18	1.83%	3.39%	3.46%
Sub-Total: Distribution (based on two-tier RPP prices)			**73.12**			**86.84**	**13.72**	**18.76%**	**29.51%**	**30.10%**
Sub-Total: Distribution (based on TOU prices)			**72.18**			**85.89**	**13.70**	**18.98%**	**29.19%**	**29.77%**
Retail Transmission Rate – Network Service Rate	1,939	0.0059	11.38	1,941	0.0053	10.29	-1.09	-9.62%	3.50%	3.57%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,939	0.0050	9.69	1,941	0.0044	8.54	-1.15	-11.89%	2.90%	2.96%
Sub-Total: Retail Transmission			**21.07**			**18.83**	**-2.25**	**-10.66%**	**6.40%**	**6.53%**
Sub-Total: Delivery (based on two-tier RPP prices)			**94.19**			**105.66**	**11.47**	**12.18%**	**35.91%**	**36.63%**
Sub-Total: Delivery (based on TOU prices)			**93.26**			**104.71**	**11.45**	**12.28%**	**35.59%**	**36.30%**
Wholesale Market Service Rate	1,939	0.0036	6.98	1,941	0.0036	6.99	0.01	0.11%	2.37%	2.42%
Rural Rate Protection Charge	1,939	0.0003	0.58	1,941	0.0003	0.58	0.00	0.11%	0.20%	0.20%
Ontario Electricity Support Program Charge	1,939	0.0000	0.00	1,941	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.09%
Sub-Total: Regulatory			**7.81**			**7.82**	**0.01**	**0.11%**	**2.66%**	**2.71%**
Debt Retirement Charge (DRC)	1,819	0.007	**12.74**	1,819	0.007	**12.74**	**0.00**	**0.00%**	**4.33%**	**4.41%**
Total Electricty Charge on Two-Tier RPP			**268.74**			**280.22**	**11.48**	**4.27%**	**95.24%**	
HST		0.13	34.94		0.13	36.43	1.49	4.27%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**303.67**			**316.65**	**12.97**	**4.27%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-21.50		-0.08	-22.42	-0.92	-4.27%	-7.62%	
Total Amount on Two-Tier RPP			**282.17**			**294.23**	**12.05**	**4.27%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**263.29**			**274.75**	**11.46**	**4.35%**		**95.24%**
HST		0.13	34.23		0.13	35.72	1.49	4.35%		12.38%
Total Electricity Charge on TOU (including HST)			**297.52**			**310.47**	**12.95**	**4.35%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-21.06		-0.08	-21.98	-0.92	-4.35%		-7.62%
Total Amount on TOU			**276.45**			**288.49**	**12.04**	**4.35%**		**100.00%**

2021 Bill Impacts (Typical Consumption Level)

Rate Class	AGSe	HCHI_GS<50
Monthly Consumption (kWh)	2,000	2,000
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	2133.4	2131
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	18.04%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	35.15%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**53.19%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		27.02%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.33%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		15.19%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**51.34%**	**52.54%**
Service Charge	1	26.94	26.94	1	40.92	40.92	13.98	51.89%	12.78%	13.08%
Fixed Acquisition Agreement Rider	1	-0.27	-0.27	1	0.00	0.00	0.27	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0190	38.00	2,000	0.0188	37.60	-0.40	-1.05%	11.75%	12.02%
Low Voltage Service Rate	2,000	0.0004	0.80	2,000	0.0000	0.00	-0.80	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,000	-0.0002	-0.40	2,000	0.0000	0.00	0.40	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**65.07**			**78.52**	**13.45**	**20.67%**	**24.53%**	**25.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	131	0.0900	11.79	133	0.0900	12.01	0.22	1.83%	3.75%	3.84%
Line Losses on Cost of Power (based on TOU prices)	131	0.0822	10.76	133	0.0822	10.96	0.20	1.83%	3.42%	3.50%
Sub-Total: Distribution (based on two-tier RPP prices)			**77.65**			**91.32**	**13.67**	**17.60%**	**28.53%**	**29.20%**
Sub-Total: Distribution (based on TOU prices)			**76.62**			**90.27**	**13.65**	**17.81%**	**28.20%**	**28.86%**
Retail Transmission Rate – Network Service Rate	2,131	0.0059	12.51	2,133	0.0053	11.31	-1.20	-9.62%	3.53%	3.62%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,131	0.0050	10.65	2,133	0.0044	9.39	-1.27	-11.89%	2.93%	3.00%
Sub-Total: Retail Transmission			**23.16**			**20.69**	**-2.47**	**-10.66%**	**6.47%**	**6.62%**
Sub-Total: Delivery (based on two-tier RPP prices)			**100.81**			**112.01**	**11.20**	**11.11%**	**35.00%**	**35.81%**
Sub-Total: Delivery (based on TOU prices)			**99.79**			**110.96**	**11.18**	**11.20%**	**34.67%**	**35.48%**
Wholesale Market Service Rate	2,131	0.0036	7.67	2,133	0.0036	7.68	0.01	0.11%	2.40%	2.46%
Rural Rate Protection Charge	2,131	0.0003	0.64	2,133	0.0003	0.64	0.00	0.11%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,131	0.0000	0.00	2,133	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.56**			**8.57**	**0.01**	**0.11%**	**2.68%**	**2.74%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.37%**	**4.48%**
Total Electricty Charge on Two-Tier RPP			**293.62**			**304.83**	**11.21**	**3.82%**	**95.24%**	
HST		0.13	38.17		0.13	39.63	1.46	3.82%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**331.80**			**344.46**	**12.66**	**3.82%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.49		-0.08	-24.39	-0.90	-3.82%	-7.62%	
Total Amount on Two-Tier RPP			**308.31**			**320.07**	**11.77**	**3.82%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**286.67**			**297.85**	**11.19**	**3.90%**		**95.24%**
HST		0.13	37.27		0.13	38.72	1.45	3.90%		12.38%
Total Electricity Charge on TOU (including HST)			**323.93**			**336.58**	**12.64**	**3.90%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-22.93		-0.08	-23.83	-0.89	-3.90%		-7.62%
Total Amount on TOU			**301.00**			**312.75**	**11.75**	**3.90%**		**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AGSe	HCHI_GS<50
Monthly Consumption (kWh)	15,000	15,000
Peak (kW)	0	0
Loss factor	1.0667	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	16000.5	15982.5
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.65%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	58.81%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**61.46%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		30.78%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.76%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		17.31%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**56.51%**	**59.85%**
Service Charge	1	26.94	26.94	1	40.92	40.92	13.98	51.89%	1.88%	1.99%
Fixed Acquisition Agreement Rider	1	-0.27	-0.27	1	0.00	0.00	0.27	-100.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0190	285.00	15,000	0.0188	282.00	-3.00	-1.05%	12.93%	13.69%
Low Voltage Service Rate	15,000	0.0004	6.00	15,000	0.0000	0.00	-6.00	-100.00%	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	15,000	-0.0002	-3.00	15,000	0.0000	0.00	3.00	100.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**314.67**			**322.92**	**8.25**	**2.62%**	**14.81%**	**15.68%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.04%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	982	0.0900	88.42	1,001	0.0900	90.05	1.62	1.83%	4.13%	4.37%
Line Losses on Cost of Power (based on TOU prices)	982	0.0822	80.72	1,001	0.0822	82.20	1.48	1.83%	3.77%	3.99%
Sub-Total: Distribution (based on two-tier RPP prices)			**403.89**			**413.76**	**9.87**	**2.44%**	**18.97%**	**20.09%**
Sub-Total: Distribution (based on TOU prices)			**396.18**			**405.91**	**9.73**	**2.46%**	**18.61%**	**19.71%**
Retail Transmission Rate – Network Service Rate	15,983	0.0059	93.83	16,001	0.0053	84.80	-9.03	-9.62%	3.89%	4.12%
Retail Transmission Rate – Line and Transformation Connection Service Rate	15,983	0.0050	79.90	16,001	0.0044	70.40	-9.50	-11.89%	3.23%	3.42%
Sub-Total: Retail Transmission			**173.73**			**155.20**	**-18.52**	**-10.66%**	**7.12%**	**7.54%**
Sub-Total: Delivery (based on two-tier RPP prices)			**577.61**			**568.96**	**-8.65**	**-1.50%**	**26.09%**	**27.63%**
Sub-Total: Delivery (based on TOU prices)			**569.91**			**561.12**	**-8.79**	**-1.54%**	**25.73%**	**27.25%**
Wholesale Market Service Rate	15,983	0.0036	57.54	16,001	0.0036	57.60	0.06	0.11%	2.64%	2.80%
Rural Rate Protection Charge	15,983	0.0003	4.79	16,001	0.0003	4.80	0.01	0.11%	0.22%	0.23%
Ontario Electricity Support Program Charge	15,983	0.0000	0.00	16,001	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.58**			**62.65**	**0.07**	**0.11%**	**2.87%**	**3.04%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.81%**	**5.10%**
Total Electricty Charge on Two-Tier RPP			**2,085.44**			**2,076.86**	**-8.58**	**-0.41%**	**95.24%**	
HST		0.13	271.11		0.13	269.99	-1.12	-0.41%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,356.55**			**2,346.85**	**-9.70**	**-0.41%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-166.84		-0.08	-166.15	0.69	0.41%	-7.62%	
Total Amount on Two-Tier RPP			**2,189.72**			**2,180.70**	**-9.01**	**-0.41%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**1,969.89**			**1,961.17**	**-8.72**	**-0.44%**		**95.24%**
HST		0.13	256.09		0.13	254.95	-1.13	-0.44%		12.38%
Total Electricity Charge on TOU (including HST)			**2,225.98**			**2,216.12**	**-9.86**	**-0.44%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-157.59		-0.08	-156.89	0.70	0.44%		-7.62%
Total Amount on TOU			**2,068.39**			**2,059.23**	**-9.16**	**-0.44%**		**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AGSd	NPDI_GS >50
Monthly Consumption (kWh)	15,000	15,000
Peak (kW)	60	60
Loss factor	1.0563	1.0564
Load factor	34%	34%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	15,845	15,846
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,846	0.077	1,220.14	15,845	0.077	1,220.03	-0.12	-0.01%	51.30%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,220.14**			**1,220.03**	**-0.12**	**-0.01%**	**51.30%**
Service Charge	1	245.55	245.55	1	206.23	206.23	-39.32	-16.01%	8.67%
Fixed Acquisition Agreement Rider	1	-3.61	-3.61	1	0.00	0.00	3.61	100.00%	0.00%
Distribution Volumetric Rate	60	3.9602	237.61	60	5.1666	310.00	72.38	30.46%	13.03%
Low Voltage Service Rate	60	0.3050	18.30	60	0.0000	0.00	-18.30	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	60	-0.0583	-3.50	60	0.0000	0.00	3.50	-100.00%	0.00%
Sub-Total: Distribution			**494.35**			**516.23**	**21.87**	**4.42%**	**21.70%**
Retail Transmission Rate – Network Service Rate	60	2.5454	152.72	60	1.8483	110.90	-41.83	-27.39%	4.66%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.2385	74.31	60	1.5101	90.61	16.30	21.93%	3.81%
Sub-Total: Retail Transmission			**227.03**			**201.50**	**-25.53**	**-11.25%**	**8.47%**
Sub-Total: Delivery			**721.39**			**717.73**	**-3.66**	**-0.51%**	**30.18%**
Wholesale Market Service Rate	15,846	0.0036	57.05	15,845	0.0036	57.04	-0.01	-0.01%	2.40%
Rural Rate Protection Charge	15,846	0.0003	4.75	15,845	0.0003	4.75	0.00	-0.01%	0.20%
Ontario Electricity Support Program Charge	15,846	0.0000	0.00	15,845	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.05**			**62.04**	**-0.01**	**-0.01%**	**2.61%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.41%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,108.58**			**2,104.80**	**-3.78**	**-0.18%**	**88.50%**
HST		0.13	274.12		0.13	273.62	-0.49	-0.18%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,382.69**			**2,378.42**	**-4.27**	**-0.18%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,382.69**			**2,378.42**	**-4.27**	**-0.18%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AGSd	NPDI_GS >50
Monthly Consumption (kWh)	57,223	57,223
Peak (kW)	161	161
Loss factor	1.0563	1.0564
Load factor	49%	49%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	60,444	60,450
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	60,450	0.077	4,654.66	60,444	0.077	4,654.21	-0.44	-0.01%	59.96%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,654.66**			**4,654.21**	**-0.44**	**-0.01%**	**59.96%**
Service Charge	1	245.55	245.55	1	206.23	206.23	-39.32	-16.01%	2.66%
Fixed Acquisition Agreement Rider	1	-3.61	-3.61	1	0.00	0.00	3.61	100.00%	0.00%
Distribution Volumetric Rate	161	3.9602	637.41	161	5.1666	831.58	194.17	30.46%	10.71%
Low Voltage Service Rate	161	0.3050	49.09	161	0.0000	0.00	-49.09	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	161	-0.0583	-9.38	161	0.0000	0.00	9.38	-100.00%	0.00%
Sub-Total: Distribution			**919.05**			**1,037.81**	**118.76**	**12.92%**	**13.37%**
Retail Transmission Rate – Network Service Rate	161	2.5454	409.69	161	1.8483	297.49	-112.20	-27.39%	3.83%
Retail Transmission Rate – Line and Transformation Connection Service Rate	161	1.2385	199.34	161	1.5101	243.06	43.71	21.93%	3.13%
Sub-Total: Retail Transmission			**609.03**			**540.55**	**-68.49**	**-11.25%**	**6.96%**
Sub-Total: Delivery			**1,528.09**			**1,578.36**	**50.27**	**3.29%**	**20.33%**
Wholesale Market Service Rate	60,450	0.0036	217.62	60,444	0.0036	217.60	-0.02	-0.01%	2.80%
Rural Rate Protection Charge	60,450	0.0003	18.14	60,444	0.0003	18.13	0.00	-0.01%	0.23%
Ontario Electricity Support Program Charge	60,450	0.0000	0.00	60,444	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**236.01**			**235.98**	**-0.02**	**-0.01%**	**3.04%**
Debt Retirement Charge (DRC)	57,223	0.007	**400.56**	57,223	0.007	**400.56**	**0.00**	**0.00%**	**5.16%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,819.31**			**6,869.11**	**49.81**	**0.73%**	**88.50%**
HST		0.13	886.51		0.13	892.98	6.48	0.73%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,705.81**			**7,762.10**	**56.28**	**0.73%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,705.81**			**7,762.10**	**56.28**	**0.73%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AGSd	NPDI_GS >50
Monthly Consumption (kWh)	175,000	175,000
Peak (kW)	500	500
Loss factor	1.056	1.056
Load factor	48%	48%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	184,853	184,870
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	184,870	0.077	14,234.99	184,853	0.077	14,233.64	-1.35	-0.01%	61.00%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,234.99**			**14,233.64**	**-1.35**	**-0.01%**	**61.00%**
Service Charge	1	245.55	245.55	1	206.23	206.23	-39.32	-16.01%	0.88%
Fixed Acquisition Agreement Rider	1	-3.61	-3.61	1	0.00	0.00	3.61	100.00%	0.00%
Distribution Volumetric Rate	500	3.9602	1,980.10	500	5.1666	2,583.30	603.20	30.46%	11.07%
Low Voltage Service Rate	500	0.3050	152.50	500	0.0000	0.00	-152.50	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	500	-0.0583	-29.15	500	0.0000	0.00	29.15	-100.00%	0.00%
Sub-Total: Distribution			**2,345.39**			**2,789.53**	**444.14**	**18.94%**	**11.96%**
Retail Transmission Rate – Network Service Rate	500	2.5454	1,272.70	500	1.8483	924.15	-348.55	-27.39%	3.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.2385	619.25	500	1.5101	755.05	135.80	21.93%	3.24%
Sub-Total: Retail Transmission			**1,891.95**			**1,679.20**	**-212.75**	**-11.25%**	**7.20%**
Sub-Total: Delivery			**4,237.34**			**4,468.73**	**231.39**	**5.46%**	**19.15%**
Wholesale Market Service Rate	184,870	0.0036	665.53	184,853	0.0036	665.47	-0.06	-0.01%	2.85%
Rural Rate Protection Charge	184,870	0.0003	55.46	184,853	0.0003	55.46	-0.01	-0.01%	0.24%
Ontario Electricity Support Program Charge	184,870	0.0000	0.00	184,853	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**721.24**			**721.17**	**-0.07**	**-0.01%**	**3.09%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**5.25%**
Total Electricity Charge on Two-Tier RPP (before HST)			**20,418.57**			**20,648.55**	**229.97**	**1.13%**	**88.50%**
HST		0.13	2,654.41		0.13	2,684.31	29.90	1.13%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**23,072.99**			**23,332.86**	**259.87**	**1.13%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**23,072.99**			**23,332.86**	**259.87**	**1.13%**	**100.00%**

2021 Bill Impacts (Low Consumption Level)

Rate Class	AGSd	HCHI_GS >50
Monthly Consumption (kWh)	15,000	15,000
Peak (kW)	60	60
Loss factor	1.056	1.066
Load factor	34%	34%
Commodity Threshold	0	750
Monthly Consumption (kWh) - Uplifted	15,845	15,983
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,983	0.077	1,230.65	15,845	0.077	1,220.03	-10.63	-0.86%	51.30%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,230.65**			**1,220.03**	**-10.63**	**-0.86%**	**51.30%**
Service Charge	1	83.61	83.61	1	206.23	206.23	122.62	146.66%	8.67%
Fixed Acquisition Agreement Rider	1	-0.84	-0.84	1	0.00	0.00	0.84	100.00%	0.00%
Distribution Volumetric Rate	60	3.9339	236.03	60	5.1666	310.00	73.96	31.34%	13.03%
Low Voltage Service Rate	60	0.1550	9.30	60	0.0000	0.00	-9.30	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	60	-0.0393	-2.36	60	0.0000	0.00	2.36	-100.00%	0.00%
Sub-Total: Distribution			**325.75**			**516.23**	**190.48**	**58.48%**	**21.70%**
Retail Transmission Rate – Network Service Rate	60	2.5038	150.23	60	1.8483	110.90	-39.33	-26.18%	4.66%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	2.1172	127.03	60	1.5101	90.61	-36.43	-28.68%	3.81%
Sub-Total: Retail Transmission			**277.26**			**201.50**	**-75.76**	**-27.32%**	**8.47%**
Sub-Total: Delivery			**603.01**			**717.73**	**114.72**	**19.02%**	**30.18%**
Wholesale Market Service Rate	15,983	0.0036	57.54	15,845	0.0036	57.04	-0.50	-0.86%	2.40%
Rural Rate Protection Charge	15,983	0.0003	4.79	15,845	0.0003	4.75	-0.04	-0.86%	0.20%
Ontario Electricity Support Program Charge	15,983	0.0000	0.00	15,845	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.58**			**62.04**	**-0.54**	**-0.86%**	**2.61%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.41%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,001.24**			**2,104.80**	**103.56**	**5.17%**	**88.50%**
HST		0.13	260.16		0.13	273.62	13.46	5.17%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,261.41**			**2,378.42**	**117.02**	**5.17%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,261.41**			**2,378.42**	**117.02**	**5.17%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	AGSd	HCHI_GS >50
Monthly Consumption (kWh)	50,917	50,917
Peak (kW)	143	143
Loss factor	1.0563	1.0655
Load factor	49%	49%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	53,783	54,252
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	54,252	0.077	4,177.37	53,783	0.077	4,141.30	-36.07	-0.86%	59.74%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,177.37**			**4,141.30**	**-36.07**	**-0.86%**	**59.74%**
Service Charge	1	83.61	83.61	1	206.23	206.23	122.62	146.66%	2.97%
Fixed Acquisition Agreement Rider	1	-0.84	-0.84	1	0.00	0.00	0.84	100.00%	0.00%
Distribution Volumetric Rate	143	3.9339	563.40	143	5.1666	739.94	176.54	31.34%	10.67%
Low Voltage Service Rate	143	0.1550	22.20	143	0.0000	0.00	-22.20	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	143	-0.0393	-5.63	143	0.0000	0.00	5.63	-100.00%	0.00%
Sub-Total: Distribution			**662.74**			**946.17**	**283.43**	**42.77%**	**13.65%**
Retail Transmission Rate – Network Service Rate	143	2.5038	358.59	143	1.8483	264.71	-93.88	-26.18%	3.82%
Retail Transmission Rate – Line and Transformation Connection Service Rate	143	2.1172	303.22	143	1.5101	216.27	-86.95	-28.68%	3.12%
Sub-Total: Retail Transmission			**661.81**			**480.98**	**-180.83**	**-27.32%**	**6.94%**
Sub-Total: Delivery			**1,324.55**			**1,427.14**	**102.60**	**7.75%**	**20.59%**
Wholesale Market Service Rate	54,252	0.0036	195.31	53,783	0.0036	193.62	-1.69	-0.86%	2.79%
Rural Rate Protection Charge	54,252	0.0003	16.28	53,783	0.0003	16.13	-0.14	-0.86%	0.23%
Ontario Electricity Support Program Charge	54,252	0.0000	0.00	53,783	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**211.83**			**210.00**	**-1.83**	**-0.86%**	**3.03%**
Debt Retirement Charge (DRC)	50,917	0.007	**356.42**	50,917	0.007	**356.42**	**0.00**	**0.00%**	**5.14%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,070.16**			**6,134.87**	**64.70**	**1.07%**	**88.50%**
HST		0.13	789.12		0.13	797.53	8.41	1.07%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**6,859.29**			**6,932.40**	**73.11**	**1.07%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**6,859.29**			**6,932.40**	**73.11**	**1.07%**	**100.00%**

2021 Bill Impacts (High Consumption Level)

Rate Class	AGSd	HCHI_GS >50
Monthly Consumption (kWh)	175,000	175,000
Peak (kW)	500	500
Loss factor	1.056	1.066
Load factor	48%	48%
Commodity Threshold	0	0
Monthly Consumption (kWh) - Uplifted	184,853	186,463
Charge determinant	kW	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	186,463	0.077	14,357.61	184,853	0.077	14,233.64	-123.97	-0.86%	61.00%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,357.61**			**14,233.64**	**-123.97**	**-0.86%**	**61.00%**
Service Charge	1	83.61	83.61	1	206.23	206.23	122.62	146.66%	0.88%
Fixed Acquisition Agreement Rider	1	-0.8400	-0.84	1	0.00	0.00	0.84	100.00%	0.00%
Distribution Volumetric Rate	500	3.9339	1,966.95	500	5.1666	2,583.30	616.35	31.34%	11.07%
Low Voltage Service Rate	500	0.1550	77.50	500	0.0000	0.00	-77.50	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	500	-0.0393	-19.65	500	0.0000	0.00	**19.65**	**-100.00%**	0.00%
Sub-Total: Distribution			**2,107.57**			**2,789.53**	**681.96**	**32.36%**	**11.96%**
Retail Transmission Rate – Network Service Rate	500	2.5038	1,251.92	500	1.8483	924.15	-327.77	-26.18%	3.96%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.1172	1,058.62	500	1.5101	755.05	-303.57	-28.68%	3.24%
Sub-Total: Retail Transmission			**2,310.54**			**1,679.20**	**-631.34**	**-27.32%**	**7.20%**
Sub-Total: Delivery			**2,107.57**			**4,468.73**	**2,361.16**	**112.03%**	**19.15%**
Wholesale Market Service Rate	186,463	0.0036	671.27	184,853	0.0036	665.47	-5.80	-0.86%	2.85%
Rural Rate Protection Charge	186,463	0.0003	55.94	184,853	0.0003	55.46	-0.48	-0.86%	0.24%
Ontario Electricity Support Program Charge	186,463	0.0000	0.00	184,853	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**727.45**			**721.17**	**-6.28**	**-0.86%**	**3.09%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**5.25%**
Total Electricity Charge on Two-Tier RPP (before HST)			**20,728.17**			**20,648.55**	**-79.62**	**-0.38%**	**88.50%**
HST		0.13	2,694.66		0.13	2,684.31	-10.35	-0.38%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**23,422.83**			**23,332.86**	**-89.98**	**-0.38%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**23,422.83**			**23,332.86**	**-89.98**	**-0.38%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	USL	WHSI_USL
Monthly Consumption (kWh)	1,545	1,545
Peak (kW)	0	0
Loss factor	1.092	1.043
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1,687	1,611
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	21.29%
Energy Second Tier (kWh)	795	0.090	71.54	795	0.090	71.54	0.00	0.00%	26.38%
Sub-Total: Energy (RPP)			**129.29**			**129.29**	**0.00**	**0.00%**	**47.67%**
Service Charge	1	10.53	10.53	1	37.37	37.37	26.84	254.89%	13.78%
Fixed Acquisition Agreement Rider	1	-0.11	-0.11	1	0.00	0.00	0.11	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	1,545	0.0122	18.85	1,545	0.0303	46.81	27.96	148.36%	17.26%
Volumetric Acquisition Agreement Rider	1,545	-0.0001	-0.15	1,545	0.0000	0.00	0.15	100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	1,545	0.0000	0.00	1,545	0.0000	0.03	0.03	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**29.11**			**84.21**	**55.10**	**189.26%**	**31.05%**
Line Losses on Cost of Power	67	0.0900	5.99	142	0.0900	12.79	6.80	113.46%	4.72%
Sub-Total: Distribution			**35.11**			**97.00**	**61.90**	**176.32%**	**35.77%**
Retail Transmission Rate – Network Service Rate	1,611	0.0065	10.47	1,687	0.0047	7.93	-2.55	-24.30%	2.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	1,611	0.0053	8.48	1,687	0.0038	6.41	-2.06	-24.36%	2.36%
Sub-Total: Retail Transmission			**18.95**			**14.34**	**-4.61**	**-24.33%**	**5.29%**
Sub-Total: Delivery			**54.06**			**111.34**	**57.29**	**105.98%**	**41.06%**
Wholesale Market Service Rate	1,611	0.0036	5.80	1,687	0.0036	6.07	0.27	4.69%	2.24%
Rural Rate Protection Charge	1,611	0.0003	0.48	1,687	0.0003	0.51	0.02	4.69%	0.19%
Ontario Electricity Support Program Charge	1,611	0.0000	0.00	1,687	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.09%
Sub-Total: Regulatory			**6.53**			**6.83**	**0.29**	**4.51%**	**2.52%**
Debt Retirement Charge (DRC)	1,545	0.007	**10.81**	1,545	0.007	**10.81**	**0.00**	**0.00%**	**3.99%**
Total Electricity Charge on Two-Tier RPP (before HST)			**200.70**			**258.28**	**57.58**	**28.69%**	**95.24%**
HST		0.13	26.09		0.13	33.58	7.49	28.69%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**226.79**			**291.85**	**65.07**	**28.69%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.06		-0.08	-20.66	-4.61	-28.69%	-7.62%
Total Amount on Two-Tier RPP			**210.73**			**271.19**	**60.46**	**28.69%**	**100.00%**

N/A

2021 Bill Impacts (Average Consumption Level)

Rate Class	USL	NPDI_USL
Monthly Consumption (kWh)	945	945
Peak (kW)	0	0
Loss factor	1.092	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1032	999
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	32.57%
Energy Second Tier (kWh)	195	0.090	17.58	195	0.090	17.58	0.00	0.00%	9.92%
Sub-Total: Energy (RPP)			**75.33**			**75.33**	**0.00**	**0.00%**	**42.49%**
Service Charge	1	15.49	15.49	1	37.37	37.37	21.88	141.25%	21.08%
Fixed Acquisition Agreement Rider	1	-0.22	-0.22	1	0.00	0.00	0.22	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.002	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	945	0.0087	8.22	945	0.0303	28.64	20.42	248.28%	16.16%
Low Voltage Service Rate	945	0.0008	0.76	945	0.0000	0.00	-0.76	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	945	-0.0001	-0.09	945	0.0000	0.00	0.09	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	945	0.0000	0.00	945	0.0000	0.02	0.02	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**24.16**			**66.04**	**41.88**	**173.37%**	**37.24%**
Line Losses on Cost of Power	53	0.0900	4.80	87	0.0900	7.83	3.03	63.12%	4.41%
Sub-Total: Distribution			**28.96**			**73.86**	**44.91**	**155.10%**	**41.66%**
Retail Transmission Rate – Network Service Rate	999	0.0063	6.29	1,032	0.0047	4.85	-1.44	-22.88%	2.74%
Retail Transmission Rate – Line and Transformation Connection Service Rate	999	0.0031	3.10	1,032	0.0038	3.92	0.83	26.71%	2.21%
Sub-Total: Retail Transmission			**9.39**			**8.77**	**-0.61**	**-6.53%**	**4.95%**
Sub-Total: Delivery			**38.34**			**82.64**	**44.30**	**115.52%**	**46.61%**
Wholesale Market Service Rate	999	0.0036	3.60	1,032	0.0036	3.72	0.12	3.37%	2.10%
Rural Rate Protection Charge	999	0.0003	0.30	1,032	0.0003	0.31	0.01	3.37%	0.17%
Ontario Electricity Support Program Charge	999	0.0000	0.00	1,032	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%
Sub-Total: Regulatory			**4.14**			**4.28**	**0.13**	**3.17%**	**2.41%**
Debt Retirement Charge (DRC)	945	0.007	**6.62**	945	0.007	**6.62**	**0.00**	**0.00%**	**3.73%**
Total Electricity Charge on Two-Tier RPP (before HST)			**124.44**			**168.87**	**44.43**	**35.70%**	**95.24%**
HST		0.13	16.18		0.13	21.95	5.78	35.70%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**140.62**			**190.82**	**50.20**	**35.70%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.96		-0.08	-13.51	-3.55	-35.70%	-7.62%
Total Amount on Two-Tier RPP			**130.66**			**177.31**	**46.65**	**35.70%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	USL	HCHI_USL
Monthly Consumption (kWh)	551	551
Peak (kW)	0	0
Loss factor	1.092	1.066
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	601	587
Charge determinant	kWh	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	551	0.077	42.41	551	0.077	42.41	0.00	0.00%	36.08%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**42.41**			**42.41**	**0.00**	**0.00%**	**36.08%**
Service Charge	1	19.51	19.51	1	37.37	37.37	17.86	91.54%	31.79%
Fixed Acquisition Agreement Rider	1	-0.20	-0.20	1	0.00	0.00	0.20	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.002	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	551	0.0025	1.38	551	0.0303	16.69	15.31	1112.00%	14.20%
Low Voltage Service Rate	551	0.0004	0.22	551	0.0000	0.00	-0.22	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	551	0.0000	0.00	551	0.0000	0.01	0.01	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**20.89**			**54.07**	**33.18**	**158.83%**	**46.00%**
Line Losses on Cost of Power	36	0.0770	2.78	51	0.0770	3.90	1.12	40.46%	3.32%
Sub-Total: Distribution			**23.67**			**57.97**	**34.30**	**144.93%**	**49.32%**
Retail Transmission Rate – Network Service Rate	587	0.0059	3.45	601	0.0047	2.83	-0.62	-17.95%	2.40%
Retail Transmission Rate – Line and Transformation Connection Service Rate	587	0.0050	2.93	601	0.0038	2.29	-0.65	-22.10%	1.94%
Sub-Total: Retail Transmission			**6.38**			**5.11**	**-1.27**	**-19.86%**	**4.35%**
Sub-Total: Delivery			**30.05**			**63.08**	**33.04**	**109.95%**	**53.67%**
Wholesale Market Service Rate	587	0.0036	2.11	601	0.0036	2.17	0.05	2.49%	1.84%
Rural Rate Protection Charge	587	0.0003	0.18	601	0.0003	0.18	0.00	2.49%	0.15%
Ontario Electricity Support Program Charge	587	0.0000	0.00	601	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%
Sub-Total: Regulatory			**2.54**			**2.60**	**0.06**	**2.24%**	**2.21%**
Debt Retirement Charge (DRC)	551	0.007	**3.86**	551	0.007	**3.86**	**0.00**	**0.00%**	**3.28%**
Total Electricity Charge on Two-Tier RPP (before HST)			**78.85**			**111.94**	**33.09**	**41.97%**	**95.24%**
HST		0.13	10.25		0.13	14.55	4.30	41.97%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**89.10**			**126.49**	**37.40**	**41.97%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.31		-0.08	-8.96	-2.65	-41.97%	-7.62%
Total Amount on Two-Tier RPP			**82.79**			**117.54**	**34.75**	**41.97%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt	WHSI_St Lgt
Monthly Consumption (kWh)	76,826	76,826
Peak (kW)		211
Loss factor	1.092	1.0431
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	83894	80138
Charge determinant	kWh	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	0.32%
Energy Second Tier (kWh)	76,076	0.090	6,846.87	76,076	0.090	6,846.87	0.00	0.00%	37.81%
Sub-Total: Energy (RPP)			**6,904.62**			**6,904.62**	**0.00**	**0.00%**	**38.12%**
Service Charge	810	3.09	2,502.90	1	4.77	4.77	-2,498.13	-99.81%	0.03%
Fixed Acquisition Agreement Rider	810	-0.03	-24.30	1	0.00	0.00	24.30	100.00%	0.00%
Fixed Deferral/Variance Account Rider	810	0.00	0.00	1	0.01	0.01	0.01	N/A	0.00%
Distribution Volumetric Rate	211	12.4552	2,625.19	76,826	0.1069	8,212.74	5,587.55	212.84%	45.35%
Volumetric Acquisition Agreement Rider	211	-0.1246	-26.26	76,826	0.0000	0.00	26.26	100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	211	0.0000	0.00	76,826	0.0000	-0.77	-0.77	N/A	0.00%
Sub-Total: Distribution (excluding pass through)			**5,077.52**			**8,216.75**	**3,139.22**	**61.83%**	**45.37%**
Line Losses on Cost of Power	3,311	0.0900	298.01	7,068	0.0900	636.12	338.11	113.46%	3.51%
Sub-Total: Distribution			**5,375.53**			**8,852.87**	**3,477.34**	**64.69%**	**48.88%**
Retail Transmission Rate – Network Service Rate	210.8	2.0614	434.48	83,894	0.0038	321.82	-112.66	-25.93%	1.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	210.8	1.6581	349.48	83,894	0.0036	304.03	-45.44	-13.00%	1.68%
Sub-Total: Retail Transmission			**783.96**			**625.85**	**-158.10**	**-20.17%**	**3.46%**
Sub-Total: Delivery			**6,159.49**			**9,478.72**	**3,319.23**	**53.89%**	**52.34%**
Wholesale Market Service Rate	80,138	0.0036	288.50	83,894	0.0036	302.02	13.52	4.69%	1.67%
Rural Rate Protection Charge	80,138	0.0003	24.04	83,894	0.0003	25.17	1.13	4.69%	0.14%
Ontario Electricity Support Program Charge	80,138	0.0000	0.00	83,894	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**312.79**			**327.44**	**14.65**	**4.68%**	**1.81%**
Debt Retirement Charge (DRC)	76,826	0.007	**537.78**	76,826	0.007	**537.78**	**0.00**	**0.00%**	**2.97%**
Total Electricity Charge on Two-Tier RPP (before HST)			**13,914.69**			**17,248.57**	**3,333.88**	**23.96%**	**95.24%**
HST		0.13	1,808.91		0.13	2,242.31	433.40	23.96%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**15,723.60**			**19,490.89**	**3,767.29**	**23.96%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1,113.17		-0.08	-1,379.89	-266.71	-23.96%	-7.62%
Total Amount on Two-Tier RPP			**14,610.42**			**18,111.00**	**3,500.58**	**23.96%**	**100.00%**

N/A

2021 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt	NPDI_St Lgt
Monthly Consumption (kWh)	1,368	1,368
Peak (kW)		4.13
Loss factor	1.092	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	1,494	1,445
Charge determinant	kWh	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	18.19%
Energy Second Tier (kWh)	618	0.090	55.59	618	0.090	55.59	0.00	0.00%	17.51%
Sub-Total: Energy (RPP)			**113.34**			**113.34**	**0.00**	**0.00%**	**35.69%**
Service Charge	21	1.97	41.37	1	4.77	4.77	-36.60	-88.47%	1.50%
Fixed Acquisition Agreement Rider	21	-0.03	-0.63	1	0.00	0.00	0.63	100.00%	0.00%
Fixed Deferral/Variance Account Rider	21	0.00	0.00	1	0.01	0.01	0.01	N/A	0.00%
Distribution Volumetric Rate	4	7.4269	30.65	1,368	0.1069	146.21	115.55	376.96%	46.04%
Low Voltage Service Rate	4	0.2358	0.97	1,368	0.0000	0.00	-0.97	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	4	-0.1094	-0.45	1,368	0.0000	0.00	0.45	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	4	0.0000	0.00	1,368	0.0000	-0.01	-0.01	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**71.92**			**150.97**	**79.05**	**109.93%**	**47.54%**
Line Losses on Cost of Power	77	0.0900	6.94	126	0.0900	11.32	4.38	63.12%	3.57%
Sub-Total: Distribution			**78.86**			**162.29**	**83.44**	**105.80%**	**51.11%**
Retail Transmission Rate – Network Service Rate	4	1.9197	7.92	1,494	0.0038	5.73	-2.19	-27.69%	1.80%
Retail Transmission Rate – Line and Transformation Connection Service Rate	4	0.9575	3.95	1,494	0.0036	5.41	1.46	36.96%	1.70%
Sub-Total: Retail Transmission			**11.88**			**11.14**	**-0.73**	**-6.18%**	**3.51%**
Sub-Total: Delivery			**90.73**			**173.43**	**82.70**	**91.15%**	**54.62%**
Wholesale Market Service Rate	1,445	0.0036	5.20	1,494	0.0036	5.38	0.18	3.37%	1.69%
Rural Rate Protection Charge	1,445	0.0003	0.43	1,494	0.0003	0.45	0.01	3.37%	0.14%
Ontario Electricity Support Program Charge	1,445	0.0000	0.00	1,494	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%
Sub-Total: Regulatory			**5.88**			**6.07**	**0.19**	**3.23%**	**1.91%**
Debt Retirement Charge (DRC)	1,368	0.007	**9.57**	1,368	0.007	**9.57**	**0.00**	**0.00%**	**3.01%**
Total Electricity Charge on Two-Tier RPP (before HST)			**219.53**			**302.42**	**82.89**	**37.76%**	**95.24%**
HST		0.13	28.54		0.13	39.32	10.78	37.76%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**248.07**			**341.74**	**93.67**	**37.76%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-17.56		-0.08	-24.19	-6.63	-37.76%	-7.62%
Total Amount on Two-Tier RPP			**230.51**			**317.55**	**87.04**	**37.76%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt	HCHI_St Lgt
Monthly Consumption (kWh)	105,612	105,612
Peak (kW)		274
Loss factor	1.092	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	115328	112529
Charge determinant	kWh	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	0.23%
Energy Second Tier (kWh)	104,862	0.090	9,437.54	104,862	0.090	9,437.54	0.00	0.00%	37.90%
Sub-Total: Energy (RPP)			**9,495.29**			**9,495.29**	**0.00**	**0.00%**	**38.14%**
Service Charge	1,847	5.70	10,527.90	1	4.77	4.77	-10,523.13	-99.95%	0.02%
Fixed Acquisition Agreement Rider	1,847	-0.06	-110.82	1	0.00	0.00	110.82	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1,847	0.00	0.00	1	0.01	0.01	0.01	N/A	0.00%
Distribution Volumetric Rate	274	14.5882	3,998.54	105,612	0.1069	11,289.88	7,291.34	182.35%	45.34%
Low Voltage Service Rate	274	0.1130	30.97	105,612	0.0000	0.00	-30.97	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	274	-0.1459	-39.99	105,612	0.0000	0.00	39.99	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	274	0.0000	0.00	105,612	0.0000	-1.06	-1.06	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**14,406.60**			**11,293.60**	**-3,113.00**	**-21.61%**	**45.36%**
Line Losses on Cost of Power	6,918	0.0900	622.58	9,716	0.0900	874.46	251.88	40.46%	3.51%
Sub-Total: Distribution			**15,029.18**			**12,168.06**	**-2,861.12**	**-19.04%**	**48.87%**
Retail Transmission Rate – Network Service Rate	274	1.8085	495.69	115,328	0.0038	442.40	-53.30	-10.75%	1.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	274	1.5210	416.89	115,328	0.0036	417.95	1.05	0.25%	1.68%
Sub-Total: Retail Transmission			**912.59**			**860.35**	**-52.24**	**-5.72%**	**3.46%**
Sub-Total: Delivery			**15,941.77**			**13,028.41**	**-2,913.36**	**-18.27%**	**52.33%**
Wholesale Market Service Rate	112,529	0.0036	405.10	115,328	0.0036	415.18	10.08	2.49%	1.67%
Rural Rate Protection Charge	112,529	0.0003	33.76	115,328	0.0003	34.60	0.84	2.49%	0.14%
Ontario Electricity Support Program Charge	112,529	0.0000	0.00	115,328	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**439.11**			**450.03**	**10.91**	**2.49%**	**1.81%**
Debt Retirement Charge (DRC)	105,612	0.007	**739.28**	105,612	0.007	**739.28**	**0.00**	**0.00%**	**2.97%**
Total Electricity Charge on Two-Tier RPP (before HST)			**26,615.45**			**23,713.01**	**-2,902.44**	**-10.91%**	**95.24%**
HST		0.13	3,460.01		0.13	3,082.69	-377.32	-10.91%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**30,075.46**			**26,795.70**	**-3,279.76**	**-10.91%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-2,129.24		-0.08	-1,897.04	232.20	10.91%	-7.62%
Total Amount on Two-Tier RPP			**27,946.23**			**24,898.66**	**-3,047.56**	**-10.91%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt	NPDI_Sen Lgt
Monthly Consumption (kWh)	126	126
Peak (kW)	0	0.5
Loss factor	1.092	1.0564
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	138	133
Charge determinant	kWh	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	126	0.077	9.70	126	0.077	9.70	0.00	0.00%	26.83%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**9.70**			**9.70**	**0.00**	**0.00%**	**26.83%**
Service Charge	1	6.53	6.53	1	3.72	3.72	-2.81	-43.03%	10.29%
Fixed Acquisition Agreement Rider	1	-0.09	-0.09	1	0.00	0.00	0.09	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.01	0.01	0.01	N/A	0.02%
Distribution Volumetric Rate	0.5	19.433	8.83	126	0.1383	17.43	8.60	97.46%	48.20%
Low Voltage Service Rate	0.5	0.2407	0.11	126	0.0000	0.00	-0.11	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	0.5	-0.2862	-0.13	126	0.0000	0.00	0.13	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	0.5	0.0000	0.00	126	-0.0001	-0.01	-0.01	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**15.25**			**21.15**	**5.90**	**38.71%**	**58.48%**
Line Losses on Cost of Power	7	0.0770	0.55	12	0.0770	0.89	0.35	63.12%	2.47%
Sub-Total: Distribution			**15.79**			**22.04**	**6.25**	**39.55%**	**60.95%**
Retail Transmission Rate – Network Service Rate	0.5	1.9294	0.88	138	0.0038	0.53	-0.35	-39.76%	1.46%
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.5	0.9774	0.44	138	0.0036	0.50	0.05	12.34%	1.38%
Sub-Total: Retail Transmission			**1.32**			**1.03**	**-0.29**	**-22.24%**	**2.84%**
Sub-Total: Delivery			**17.11**			**23.07**	**5.95**	**34.79%**	**63.79%**
Wholesale Market Service Rate	133	0.0036	0.48	138	0.0036	0.50	0.02	3.37%	1.37%
Rural Rate Protection Charge	133	0.0003	0.04	138	0.0003	0.04	0.00	3.37%	0.11%
Ontario Electricity Support Program Charge	133	0.0000	0.00	138	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.69%
Sub-Total: Regulatory			**0.77**			**0.79**	**0.02**	**2.27%**	**2.18%**
Debt Retirement Charge (DRC)	126	0.007	**0.88**	126	0.007	**0.88**	**0.00**	**0.00%**	**2.44%**
Total Electricity Charge on Two-Tier RPP (before HST)			**28.47**			**34.44**	**5.97**	**20.97%**	**95.24%**
HST		0.13	3.70		0.13	4.48	0.78	20.97%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**32.17**			**38.92**	**6.75**	**20.97%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-2.28		-0.08	-2.76	-0.48	-20.97%	-7.62%
Total Amount on Two-Tier RPP			**29.89**			**36.16**	**6.27**	**20.97%**	**100.00%**

2021 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt	HCHI_Sen Lgt
Monthly Consumption (kWh)	131	131
Peak (kW)	0	0
Loss factor	1.092	1.0655
Commodity Threshold	750	750
Monthly Consumption (kWh) - Uplifted	143	140
Charge determinant	kWh	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	131	0.077	10.09	131	0.077	10.09	0.00	0.00%	26.95%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**10.09**			**10.09**	**0.00**	**0.00%**	**26.95%**
Service Charge	1	14.23	14.23	1	3.72	3.72	-10.51	-73.86%	9.93%
Fixed Acquisition Agreement Rider	1	-0.14	-0.14	1	0.00	0.00	0.14	100.00%	0.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.01	0.01	0.01	N/A	0.02%
Distribution Volumetric Rate	0.34	36.726	12.49	131	0.1383	18.13	5.63	45.10%	48.41%
Low Voltage Service Rate	0.34	0.1099	0.04	131	0.0000	0.00	-0.04	-100.00%	0.00%
Volumetric Acquisition Agreement Rider	0.34	-0.3673	-0.12	131	0.0000	0.00	0.12	-100.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	0.34	0.0000	0.00	131	-0.0001	-0.01	-0.01	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**26.50**			**21.85**	**-4.65**	**-17.55%**	**58.34%**
Line Losses on Cost of Power	9	0.0770	0.66	12	0.0770	0.93	0.27	40.46%	2.48%
Sub-Total: Distribution			**27.16**			**22.78**	**-4.38**	**-16.14%**	**60.82%**
Retail Transmission Rate – Network Service Rate	0.34	1.8176	0.62	143	0.0038	0.55	-0.07	-11.20%	1.47%
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.34	1.5528	0.53	143	0.0036	0.52	-0.01	-1.80%	1.39%
Sub-Total: Retail Transmission			**1.15**			**1.07**	**-0.08**	**-6.87%**	**2.85%**
Sub-Total: Delivery			**28.30**			**23.84**	**-4.46**	**-15.76%**	**63.67%**
Wholesale Market Service Rate	140	0.0036	0.50	143	0.0036	0.52	0.01	2.49%	1.38%
Rural Rate Protection Charge	140	0.0003	0.04	143	0.0003	0.04	0.00	2.49%	0.11%
Ontario Electricity Support Program Charge	140	0.0000	0.00	143	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.67%
Sub-Total: Regulatory			**0.79**			**0.81**	**0.01**	**1.70%**	**2.16%**
Debt Retirement Charge (DRC)	131	0.007	**0.92**	131	0.007	**0.92**	**0.00**	**0.00%**	**2.45%**
Total Electricity Charge on Two-Tier RPP (before HST)			**40.11**			**35.66**	**-4.45**	**-11.09%**	**95.24%**
HST		0.13	5.21		0.13	4.64	-0.58	-11.09%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**45.32**			**40.30**	**-5.03**	**-11.09%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-3.21		-0.08	-2.85	0.36	11.09%	-7.62%
Total Amount on Two-Tier RPP			**42.11**			**37.44**	**-4.67**	**-11.09%**	**100.00%**

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2021 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Low	350		$78.48	$0.70	1.91%	$0.73	0.94%
	Typical	750		$122.92	$0.70	1.91%	$0.73	0.60%
	Average	755		$123.47	$0.70	1.91%	$0.73	0.60%
	High	1,400		$195.12	$0.70	1.91%	$0.73	0.38%
R1	Low	400		$84.17	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.39	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.44	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.04	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.68	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.92	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.80	$0.00	0.00%	$0.00	0.00%
	High	2,300		$301.83	$0.00	0.00%	$0.00	0.00%
Seasonal	Low	50		$66.49	$5.45	9.56%	$5.72	8.60%
	Average	352		$110.35	$1.43	2.15%	$1.50	1.36%
	High	1,000		$204.46	($7.19)	-8.26%	($7.55)	-3.69%
GSe	Low	1,000		$220.42	$2.36	2.44%	$2.48	1.12%
	Typical	2,000		$406.80	$4.16	2.57%	$4.37	1.07%
	Average	1,982		$403.44	$4.13	2.57%	$4.33	1.07%
	High	15,000		$2,829.70	$27.56	2.73%	$28.94	1.02%
UGe	Low	1,000		$175.83	$1.32	2.34%	$1.39	0.79%
	Typical	2,000		$323.73	$2.12	2.43%	$2.23	0.69%
	Average	2,759		$435.99	$2.73	2.47%	$2.86	0.66%
	High	15,000		$2,246.47	$12.52	2.57%	$13.15	0.59%
GSd	Low	15,000	60	$3,147.61	$24.92	2.04%	$28.16	0.89%
	Average	36,104	128	$7,007.32	$51.34	2.07%	$58.01	0.83%
	High	175,000	500	$30,581.66	$195.82	2.09%	$221.28	0.72%
UGd	Low	15,000	60	$2,665.86	$13.47	1.80%	$15.22	0.57%
	Average	50,525	138	$7,639.32	$28.62	1.81%	$32.34	0.42%
	High	175,000	500	$26,524.11	$98.92	1.81%	$111.78	0.42%
St Lgt	Low	100		$27.37	$0.39	2.52%	$0.41	1.50%
	Average	517		$119.48	$1.56	2.45%	$1.64	1.37%
	High	2,000		$466.65	$5.71	2.61%	$6.00	1.28%
Sen Lgt	Low	20		$9.25	$0.26	4.07%	$0.28	3.00%
	Average	71		$22.20	$0.55	4.10%	$0.58	2.62%
	High	200		$54.94	$1.29	4.11%	$1.35	2.47%
USL	Low	100		$53.67	$0.99	2.45%	$1.04	1.94%
	Average	364		$91.08	$1.15	2.37%	$1.21	1.32%
	High	1,000		$185.86	$1.53	2.26%	$1.61	0.86%
DGen	Low	300	10	$396.81	$6.77	2.18%	$7.65	1.93%
	Average	1,328	12	$533.33	$8.12	2.43%	$9.18	1.72%
	High	5,000	100	$2,180.31	$67.68	5.03%	$76.48	3.51%
ST	Low	200,000	500	$26,165.27	$50.62	2.62%	$57.20	0.22%
	Average	1,601,036	2,960	$190,532.18	$152.76	2.96%	$172.62	0.09%
	High	4,000,000	10,000	$495,943.20	$445.07	3.09%	$502.93	0.10%
AUR	Low	350		$72.08	$0.81	2.63%	$0.85	1.18%
	Typical	750		$116.28	$0.81	2.63%	$0.85	0.73%
	Average	505		$89.21	$0.81	2.63%	$0.85	0.95%
	High	1,400		$188.11	$0.81	2.63%	$0.85	0.45%
AUGe	Low	1,000		$165.32	$9.71	20.37%	$10.20	6.17%
	Typical	2,000		$297.77	$13.31	20.46%	$13.98	4.69%
	Average	2,695		$389.83	$15.81	20.49%	$16.60	4.26%
	High	15,000		$2,019.68	$60.11	20.64%	$63.12	3.13%
AUGd	Low	15,000	60	$2,287.68	$154.15	34.46%	$174.19	7.61%
	Average	61,239	177	$8,049.95	$306.86	33.56%	$346.75	4.31%
	High	175,000	500	$22,519.04	$728.44	33.06%	$823.14	3.66%
AR	Low	400		$87.97	$1.06	2.62%	$1.11	1.27%
	Typical	750		$126.84	$1.06	2.62%	$1.11	0.88%
	Average	634		$113.96	$1.06	2.62%	$1.11	0.98%
	High	1,800		$243.46	$1.06	2.62%	$1.11	0.46%
AGSe	Low	1,000		$178.40	$3.64	6.10%	$3.82	2.14%
	Typical	2,000		$312.75	$4.94	6.29%	$5.19	1.66%
	Average	1,988		$311.13	$4.92	6.29%	$5.17	1.66%
	High	15,000		$2,059.23	$21.84	6.76%	$22.93	1.11%
AGSd	Low	15,000	60	$2,384.01	$115.81	22.22%	$130.87	5.49%
	Average	53,895	152	$7,342.34	$222.58	22.17%	$251.51	3.43%
	High	175,000	500	$23,379.41	$626.43	22.13%	$707.87	3.03%

2022 Bill Impacts (Low Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	370
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	34.90%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**34.90%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		18.67%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.14%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		10.50%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**37.24%**	**36.30%**
Service Charge	1	36.67	36.67	1	37.37	37.37	0.70	1.91%	48.40%	47.17%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	350	0.0000	0.00	350	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	350	0.0000	0.01	350	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.69**			**37.39**	**0.70**	**1.91%**	**48.42%**	**47.20%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.02%	1.00%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	1.99%	1.94%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.12%	2.07%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.01**			**39.71**	**0.70**	**1.79%**	**51.43%**	**50.13%**
Sub-Total: Distribution (based on TOU prices)			**39.12**			**39.82**	**0.70**	**1.79%**	**51.57%**	**50.26%**
Retail Transmission Rate – Network Service Rate	370	0.0077	2.85	370	0.0077	2.85	0.00	0.00%	3.69%	3.60%
Retail Transmission Rate – Line and Transformation Connection S	370	0.0063	2.33	370	0.0063	2.33	0.00	0.00%	3.02%	2.94%
Sub-Total: Retail Transmission			**5.18**			**5.18**	**0.00**	**0.00%**	**6.71%**	**6.54%**
Sub-Total: Delivery (based on two-tier RPP prices)			**44.19**			**44.89**	**0.70**	**1.58%**	**58.14%**	**56.67%**
Sub-Total: Delivery (based on TOU prices)			**44.30**			**45.00**	**0.70**	**1.58%**	**58.28%**	**56.80%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.72%	1.68%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.14%	0.14%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.32%	0.32%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.19%**	**2.14%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**72.84**			**73.54**	**0.70**	**0.96%**	**95.24%**	
HST		0.13	9.47		0.13	9.56	0.09	0.96%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**82.30**			**83.10**	**0.79**	**0.96%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.83		-0.08	-5.88	-0.06	-0.96%	-7.62%	
Total Amount on Two-Tier RPP			**76.48**			**77.21**	**0.73**	**0.96%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**74.74**			**75.44**	**0.70**	**0.94%**		**95.24%**
HST		0.13	9.72		0.13	9.81	0.09	0.94%		12.38%
Total Electricity Charge on TOU (including HST)			**84.46**			**85.25**	**0.79**	**0.94%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.98		-0.08	-6.04	-0.06	-0.94%		-7.62%
Total Amount on TOU			**78.48**			**79.22**	**0.73**	**0.94%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	793
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.87%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.07%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.94%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.63%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.80%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.41%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.51%**	**49.83%**
Service Charge	1	36.67	36.67	1	37.37	37.37	0.70	1.91%	30.63%	30.22%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	750	0.0000	0.00	750	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**36.70**			**37.40**	**0.70**	**1.91%**	**30.66%**	**30.25%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.15%	3.11%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	2.88%	2.84%
Sub-Total: Distribution (based on two-tier RPP prices)			**41.34**			**42.04**	**0.70**	**1.69%**	**34.46%**	**34.00%**
Sub-Total: Distribution (based on TOU prices)			**41.00**			**41.70**	**0.70**	**1.71%**	**34.19%**	**33.73%**
Retail Transmission Rate – Network Service Rate	793	0.0077	6.10	793	0.0077	6.10	0.00	0.00%	5.00%	4.94%
Retail Transmission Rate – Line and Transformation Connection S	793	0.0063	4.99	793	0.0063	4.99	0.00	0.00%	4.09%	4.04%
Sub-Total: Retail Transmission			**11.10**			**11.10**	**0.00**	**0.00%**	**9.10%**	**8.98%**
Sub-Total: Delivery (based on two-tier RPP prices)			**52.44**			**53.14**	**0.70**	**1.33%**	**43.56%**	**42.97%**
Sub-Total: Delivery (based on TOU prices)			**52.10**			**52.80**	**0.70**	**1.34%**	**43.28%**	**42.70%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.34%	2.31%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.19%	0.19%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.74%**	**2.70%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**115.48**			**116.18**	**0.70**	**0.61%**	**95.24%**	
HST		0.13	15.01		0.13	15.10	0.09	0.61%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**130.49**			**131.28**	**0.79**	**0.61%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.24		-0.08	-9.29	-0.06	-0.61%	-7.62%	
Total Amount on Two-Tier RPP			**121.25**			**121.99**	**0.73**	**0.61%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.06**			**117.76**	**0.70**	**0.60%**		**95.24%**
HST		0.13	15.22		0.13	15.31	0.09	0.60%		12.38%
Total Electricity Charge on TOU (including HST)			**132.28**			**133.07**	**0.79**	**0.60%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.36		-0.08	-9.42	-0.06	-0.60%		-7.62%
Total Amount on TOU			**122.92**			**123.65**	**0.73**	**0.60%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	755
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	798
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.69%	
Energy Second Tier (kWh)	155	0.090	13.95	155	0.090	13.95	0.00	0.00%	11.38%	
Sub-Total: Energy (RPP)			**60.15**			**60.15**	**0.00**	**0.00%**	**49.07%**	
TOU-Off Peak	491	0.065	31.90	491	0.065	31.90	0.00	0.00%		25.68%
TOU-Mid Peak	128	0.095	12.19	128	0.095	12.19	0.00	0.00%		9.82%
TOU-On Peak	136	0.132	17.94	136	0.132	17.94	0.00	0.00%		14.44%
Sub-Total: Energy (TOU)			**62.03**			**62.03**	0.00	0.00%	**50.60%**	**49.94%**
Service Charge	1	36.67	36.67	1	37.37	37.37	0.70	1.91%	30.48%	30.09%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%	0.01%
Distribution Volumetric Rate	755	0.0000	0.00	755	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	755	0.0000	0.02	755	0.0000	0.02	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**36.70**			**37.40**	**0.70**	**1.91%**	**30.51%**	**30.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.87	43	0.0900	3.87	0.00	0.00%	3.16%	3.12%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.54	43	0.0822	3.54	0.00	0.00%	2.88%	2.85%
Sub-Total: Distribution (based on two-tier RPP prices)			**41.36**			**42.06**	**0.70**	**1.69%**	**34.31%**	**33.87%**
Sub-Total: Distribution (based on TOU prices)			**41.03**			**41.73**	**0.70**	**1.71%**	**34.04%**	**33.59%**
Retail Transmission Rate – Network Service Rate	798	0.0077	6.14	798	0.0077	6.14	0.00	0.00%	5.01%	4.95%
Retail Transmission Rate – Line and Transformation Connection S	798	0.0063	5.03	798	0.0063	5.03	0.00	0.00%	4.10%	4.05%
Sub-Total: Retail Transmission			**11.17**			**11.17**	**0.00**	**0.00%**	**9.11%**	**9.00%**
Sub-Total: Delivery (based on two-tier RPP prices)			**52.54**			**53.24**	**0.70**	**1.33%**	**43.43%**	**42.86%**
Sub-Total: Delivery (based on TOU prices)			**52.20**			**52.90**	**0.70**	**1.34%**	**43.15%**	**42.59%**
Wholesale Market Service Rate	798	0.0036	2.87	798	0.0036	2.87	0.00	0.00%	2.34%	2.31%
Rural Rate Protection Charge	798	0.0003	0.24	798	0.0003	0.24	0.00	0.00%	0.20%	0.19%
Ontario Electricity Support Program Charge	798	0.0000	0.00	798	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.36**			**3.36**	**0.00**	**0.00%**	**2.74%**	**2.71%**
Debt Retirement Charge (DRC)	755	0.000	**0.00**	755	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**116.05**			**116.75**	**0.70**	**0.60%**	**95.24%**	
HST		0.13	15.09		0.13	15.18	0.09	0.60%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**131.13**			**131.92**	**0.79**	**0.60%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.28		-0.08	-9.34	-0.06	-0.60%	-7.62%	
Total Amount on Two-Tier RPP			**121.85**			**122.59**	**0.73**	**0.60%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.59**			**118.29**	**0.70**	**0.60%**		**95.24%**
HST		0.13	15.29		0.13	15.38	0.09	0.60%		12.38%
Total Electricity Charge on TOU (including HST)			**132.88**			**133.67**	**0.79**	**0.60%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.46	-0.06	-0.60%		-7.62%
Total Amount on TOU			**123.47**			**124.21**	**0.73**	**0.60%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	UR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1480
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.12%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	36.03%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**59.15%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		30.20%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.54%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		16.98%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**57.56%**	**58.73%**
Service Charge	1	36.67	36.67	1	37.37	37.37	0.70	1.91%	18.70%	19.08%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0000	0.00	1,400	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,400	0.0000	0.04	1,400	0.0000	0.04	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**36.72**			**37.42**	**0.70**	**1.91%**	**18.72%**	**19.11%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.40%	0.40%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.59%	3.67%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.28%	3.35%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.69**			**45.39**	**0.70**	**1.57%**	**22.71%**	**23.18%**
Sub-Total: Distribution (based on TOU prices)			**44.07**			**44.77**	**0.70**	**1.59%**	**22.40%**	**22.86%**
Retail Transmission Rate – Network Service Rate	1,480	0.0077	11.39	1,480	0.0077	11.39	0.00	0.00%	5.70%	5.82%
Retail Transmission Rate – Line and Transformation Connection S	1,480	0.0063	9.32	1,480	0.0063	9.32	0.00	0.00%	4.66%	4.76%
Sub-Total: Retail Transmission			**20.72**			**20.72**	**0.00**	**0.00%**	**10.37%**	**10.58%**
Sub-Total: Delivery (based on two-tier RPP prices)			**65.41**			**66.11**	**0.70**	**1.07%**	**33.08%**	**33.75%**
Sub-Total: Delivery (based on TOU prices)			**64.78**			**65.48**	**0.70**	**1.08%**	**32.77%**	**33.43%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.67%	2.72%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**3.01%**	**3.07%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**189.63**			**190.33**	**0.70**	**0.37%**	**95.24%**	
HST		0.13	24.65		0.13	24.74	0.09	0.37%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**214.28**			**215.07**	**0.79**	**0.37%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.17		-0.08	-15.23	-0.06	-0.37%	-7.62%	
Total Amount on Two-Tier RPP			**199.11**			**199.85**	**0.73**	**0.37%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**185.83**			**186.53**	**0.70**	**0.38%**		**95.24%**
HST		0.13	24.16		0.13	24.25	0.09	0.38%		12.38%
Total Electricity Charge on TOU (including HST)			**209.99**			**210.78**	**0.79**	**0.38%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.87		-0.08	-14.92	-0.06	-0.38%		-7.62%
Total Amount on TOU			**195.12**			**195.85**	**0.73**	**0.38%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	430
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	37.64%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**37.64%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		20.08%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.68%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		11.29%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**40.16%**	**39.05%**
Service Charge	1	52.31	36.43	1	58.26	36.43	0.00	0.00%	44.52%	43.28%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	400	0.0116	0.00	400	0.0066	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	400	0.0000	0.01	400	0.0000	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.44**			**36.44**	**0.00**	**0.00%**	**44.53%**	**43.30%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.97%	0.94%
Line Losses on Cost of Power (based on two-tier RPP prices)	30	0.0770	2.34	30	0.0770	2.34	0.00	0.00%	2.86%	2.78%
Line Losses on Cost of Power (based on TOU prices)	30	0.0822	2.50	30	0.0822	2.50	0.00	0.00%	3.05%	2.97%
Sub-Total: Distribution (based on two-tier RPP prices)			**39.57**			**39.57**	**0.00**	**0.00%**	**48.36%**	**47.02%**
Sub-Total: Distribution (based on TOU prices)			**39.73**			**39.73**	**0.00**	**0.00%**	**48.55%**	**47.20%**
Retail Transmission Rate – Network Service Rate	430	0.0072	3.10	430	0.0072	3.10	0.00	0.00%	3.79%	3.68%
Retail Transmission Rate – Line and Transformation Connection S	430	0.0059	2.54	430	0.0059	2.54	0.00	0.00%	3.10%	3.02%
Sub-Total: Retail Transmission			**5.64**			**5.64**	**0.00**	**0.00%**	**6.89%**	**6.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**45.21**			**45.21**	**0.00**	**0.00%**	**55.25%**	**53.71%**
Sub-Total: Delivery (based on TOU prices)			**45.37**			**45.37**	**0.00**	**0.00%**	**55.44%**	**53.90%**
Wholesale Market Service Rate	430	0.0036	1.55	430	0.0036	1.55	0.00	0.00%	1.89%	1.84%
Rural Rate Protection Charge	430	0.0003	0.13	430	0.0003	0.13	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	430	0.0000	0.00	430	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.31%	0.30%
Sub-Total: Regulatory			**1.93**			**1.93**	**0.00**	**0.00%**	**2.36%**	**2.29%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**77.94**			**77.94**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.13		0.13	10.13	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**88.07**			**88.07**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.24		-0.08	-6.24	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**81.84**			**81.84**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**80.16**			**80.16**	**0.00**	**0.00%**		**95.24%**
HST		0.13	10.42		0.13	10.42	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**90.58**			**90.58**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.41		-0.08	-6.41	0.00	0.00%		-7.62%
Total Amount on TOU			**84.17**			**84.17**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	807
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.92%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.08%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**49.00%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.68%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.82%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.44%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**50.57%**	**49.94%**
Service Charge	1	52.31	36.43	1	58.26	36.43	0.00	0.00%	29.90%	29.53%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	750	0.0116	0.00	750	0.0066	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	750	0.0000	0.02	750	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**29.92%**	**29.54%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.65%	0.64%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	4.21%	4.16%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	3.84%	3.80%
Sub-Total: Distribution (based on two-tier RPP prices)			**42.37**			**42.37**	**0.00**	**0.00%**	**34.77%**	**34.34%**
Sub-Total: Distribution (based on TOU prices)			**41.92**			**41.92**	**0.00**	**0.00%**	**34.41%**	**33.98%**
Retail Transmission Rate – Network Service Rate	807	0.0072	5.81	807	0.0072	5.81	0.00	0.00%	4.77%	4.71%
Retail Transmission Rate – Line and Transformation Connection S	807	0.0059	4.76	807	0.0059	4.76	0.00	0.00%	3.91%	3.86%
Sub-Total: Retail Transmission			**10.57**			**10.57**	**0.00**	**0.00%**	**8.68%**	**8.57%**
Sub-Total: Delivery (based on two-tier RPP prices)			**52.94**			**52.94**	**0.00**	**0.00%**	**43.45%**	**42.91%**
Sub-Total: Delivery (based on TOU prices)			**52.49**			**52.49**	**0.00**	**0.00%**	**43.08%**	**42.54%**
Wholesale Market Service Rate	807	0.0036	2.91	807	0.0036	2.91	0.00	0.00%	2.38%	2.35%
Rural Rate Protection Charge	807	0.0003	0.24	807	0.0003	0.24	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	807	0.0000	0.00	807	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.20%
Sub-Total: Regulatory			**3.40**			**3.40**	**0.00**	**0.00%**	**2.79%**	**2.75%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**116.04**			**116.04**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.08		0.13	15.08	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**131.12**			**131.12**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.28		-0.08	-9.28	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**121.84**			**121.84**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**117.51**			**117.51**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.28		0.13	15.28	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**132.79**			**132.79**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.40		-0.08	-9.40	0.00	0.00%		-7.62%
Total Amount on TOU			**123.39**			**123.39**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	920
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	990
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	32.45%	
Energy Second Tier (kWh)	320	0.090	28.80	320	0.090	28.80	0.00	0.00%	20.23%	
Sub-Total: Energy (RPP)			**75.00**			**75.00**	**0.00**	**0.00%**	**52.67%**	
TOU-Off Peak	598	0.065	38.87	598	0.065	38.87	0.00	0.00%		27.29%
TOU-Mid Peak	156	0.095	14.86	156	0.095	14.86	0.00	0.00%		10.43%
TOU-On Peak	166	0.132	21.86	166	0.132	21.86	0.00	0.00%		15.35%
Sub-Total: Energy (TOU)			**75.59**			**75.59**	0.00	0.00%	**53.08%**	**53.07%**
Service Charge	1	52.31	36.43	1	58.26	36.43	0.00	0.00%	25.58%	25.58%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	920	0.0116	0.00	920	0.0066	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	920	0.0000	0.02	920	0.0000	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.45**			**36.45**	**0.00**	**0.00%**	**25.60%**	**25.59%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.55%	0.55%
Line Losses on Cost of Power (based on two-tier RPP prices)	70	0.0900	6.29	70	0.0900	6.29	0.00	0.00%	4.42%	4.42%
Line Losses on Cost of Power (based on TOU prices)	70	0.0822	5.74	70	0.0822	5.74	0.00	0.00%	4.03%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.54**			**43.54**	**0.00**	**0.00%**	**30.57%**	**30.56%**
Sub-Total: Distribution (based on TOU prices)			**42.99**			**42.99**	**0.00**	**0.00%**	**30.19%**	**30.18%**
Retail Transmission Rate – Network Service Rate	990	0.0072	7.13	990	0.0072	7.13	0.00	0.00%	5.01%	5.00%
Retail Transmission Rate – Line and Transformation Connection S	990	0.0059	5.84	990	0.0059	5.84	0.00	0.00%	4.10%	4.10%
Sub-Total: Retail Transmission			**12.97**			**12.97**	**0.00**	**0.00%**	**9.11%**	**9.10%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.50**			**56.50**	**0.00**	**0.00%**	**39.68%**	**39.67%**
Sub-Total: Delivery (based on TOU prices)			**55.95**			**55.95**	**0.00**	**0.00%**	**39.30%**	**39.28%**
Wholesale Market Service Rate	990	0.0036	3.56	990	0.0036	3.56	0.00	0.00%	2.50%	2.50%
Rural Rate Protection Charge	990	0.0003	0.30	990	0.0003	0.30	0.00	0.00%	0.21%	0.21%
Ontario Electricity Support Program Charge	990	0.0000	0.00	990	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%	0.18%
Sub-Total: Regulatory			**4.11**			**4.11**	**0.00**	**0.00%**	**2.89%**	**2.89%**
Debt Retirement Charge (DRC)	920	0.000	**0.00**	920	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**135.61**			**135.61**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	17.63		0.13	17.63	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**153.24**			**153.24**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.85		-0.08	-10.85	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**142.39**			**142.39**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**135.65**			**135.65**	**0.00**	**0.00%**		**95.24%**
HST		0.13	17.63		0.13	17.63	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**153.29**			**153.29**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-10.85		-0.08	-10.85	0.00	0.00%		-7.62%
Total Amount on TOU			**142.44**			**142.44**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	R1
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.076
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1937
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.57%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	43.41%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.98%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.55%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		12.06%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.74%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	0.00	0.00%	**59.44%**	**61.35%**
Service Charge	1	52.31	36.43	1	58.26	36.43	0.00	0.00%	14.64%	15.11%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0116	0.00	1,800	0.0066	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,800	0.0000	0.04	1,800	0.0000	0.04	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.47**			**36.47**	**0.00**	**0.00%**	**14.66%**	**15.13%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.32%	0.33%
Line Losses on Cost of Power (based on two-tier RPP prices)	137	0.0900	12.31	137	0.0900	12.31	0.00	0.00%	4.95%	5.11%
Line Losses on Cost of Power (based on TOU prices)	137	0.0822	11.24	137	0.0822	11.24	0.00	0.00%	4.52%	4.66%
Sub-Total: Distribution (based on two-tier RPP prices)			**49.57**			**49.57**	**0.00**	**0.00%**	**19.92%**	**20.57%**
Sub-Total: Distribution (based on TOU prices)			**48.50**			**48.50**	**0.00**	**0.00%**	**19.49%**	**20.12%**
Retail Transmission Rate – Network Service Rate	1,937	0.0072	13.94	1,937	0.0072	13.94	0.00	0.00%	5.61%	5.79%
Retail Transmission Rate – Line and Transformation Connection S	1,937	0.0059	11.43	1,937	0.0059	11.43	0.00	0.00%	4.59%	4.74%
Sub-Total: Retail Transmission			**25.37**			**25.37**	**0.00**	**0.00%**	**10.20%**	**10.53%**
Sub-Total: Delivery (based on two-tier RPP prices)			**74.94**			**74.94**	**0.00**	**0.00%**	**30.12%**	**31.09%**
Sub-Total: Delivery (based on TOU prices)			**73.87**			**73.87**	**0.00**	**0.00%**	**29.69%**	**30.65%**
Wholesale Market Service Rate	1,937	0.0036	6.97	1,937	0.0036	6.97	0.00	0.00%	2.80%	2.89%
Rural Rate Protection Charge	1,937	0.0003	0.58	1,937	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,937	0.0000	0.00	1,937	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.80**			**7.80**	**0.00**	**0.00%**	**3.14%**	**3.24%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**236.95**			**236.95**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	30.80		0.13	30.80	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**267.75**			**267.75**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.96		-0.08	-18.96	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**248.79**			**248.79**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**229.56**			**229.56**	**0.00**	**0.00%**		**95.24%**
HST		0.13	29.84		0.13	29.84	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**259.41**			**259.41**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.37		-0.08	-18.37	0.00	0.00%		-7.62%
Total Amount on TOU			**241.04**			**241.04**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	450
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	497
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	450	0.077	34.65	450	0.077	34.65	0.00	0.00%	39.38%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**34.65**			**34.65**	**0.00**	**0.00%**	**39.38%**	
TOU-Off Peak	293	0.065	19.01	293	0.065	19.01	0.00	0.00%		20.97%
TOU-Mid Peak	77	0.095	7.27	77	0.095	7.27	0.00	0.00%		8.01%
TOU-On Peak	81	0.132	10.69	81	0.132	10.69	0.00	0.00%		11.79%
Sub-Total: Energy (TOU)			**36.97**			**36.97**	0.00	0.00%	**42.02%**	**40.77%**
Service Charge	1	55.26	36.43	1	68.12	36.43	0.00	0.00%	41.40%	40.17%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	450	0.0201	0.00	450	0.0117	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	450	0.0000	0.00	450	0.0000	0.00	0.00	0.00%	0.01%	0.00%
Sub-Total: Distribution (excluding pass through)			**36.41**			**36.41**	**0.00**	**0.00%**	**41.39%**	**40.16%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.90%	0.87%
Line Losses on Cost of Power (based on two-tier RPP prices)	47	0.0770	3.64	47	0.0770	3.64	0.00	0.00%	4.13%	4.01%
Line Losses on Cost of Power (based on TOU prices)	47	0.0822	3.88	47	0.0822	3.88	0.00	0.00%	4.41%	4.28%
Sub-Total: Distribution (based on two-tier RPP prices)			**40.84**			**40.84**	**0.00**	**0.00%**	**46.42%**	**45.04%**
Sub-Total: Distribution (based on TOU prices)			**41.09**			**41.09**	**0.00**	**0.00%**	**46.70%**	**45.31%**
Retail Transmission Rate – Network Service Rate	497	0.0068	3.38	497	0.0068	3.38	0.00	0.00%	3.84%	3.73%
Retail Transmission Rate – Line and Transformation Connection S	497	0.0055	2.73	497	0.0055	2.73	0.00	0.00%	3.11%	3.02%
Sub-Total: Retail Transmission			**6.12**			**6.12**	**0.00**	**0.00%**	**6.95%**	**6.74%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.96**			**46.96**	**0.00**	**0.00%**	**53.37%**	**51.78%**
Sub-Total: Delivery (based on TOU prices)			**47.20**			**47.20**	**0.00**	**0.00%**	**53.65%**	**52.05%**
Wholesale Market Service Rate	497	0.0036	1.79	497	0.0036	1.79	0.00	0.00%	2.03%	1.97%
Rural Rate Protection Charge	497	0.0003	0.15	497	0.0003	0.15	0.00	0.00%	0.17%	0.16%
Ontario Electricity Support Program Charge	497	0.0000	0.00	497	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.28%	0.28%
Sub-Total: Regulatory			**2.19**			**2.19**	**0.00**	**0.00%**	**2.49%**	**2.41%**
Debt Retirement Charge (DRC)	450	0.000	**0.00**	450	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**83.80**			**83.80**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	10.89		0.13	10.89	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**94.69**			**94.69**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.70		-0.08	-6.70	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**87.99**			**87.99**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**86.36**			**86.36**	**0.00**	**0.00%**		**95.24%**
HST		0.13	11.23		0.13	11.23	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**97.59**			**97.59**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.91		-0.08	-6.91	0.00	0.00%		-7.62%
Total Amount on TOU			**90.68**			**90.68**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	829
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	37.39%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.93%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**48.32%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		25.37%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.70%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		14.27%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**49.87%**	**49.33%**
Service Charge	1	55.26	36.43	1	68.12	36.43	0.00	0.00%	29.49%	29.16%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.02%	-0.02%
Distribution Volumetric Rate	750	0.0201	0.00	750	0.0117	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	750	0.0000	0.01	750	0.00001	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**29.47%**	**29.15%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.64%	0.63%
Line Losses on Cost of Power (based on two-tier RPP prices)	79	0.0900	7.09	79	0.0900	7.09	0.00	0.00%	5.74%	5.67%
Line Losses on Cost of Power (based on TOU prices)	79	0.0822	6.47	79	0.0822	6.47	0.00	0.00%	5.24%	5.18%
Sub-Total: Distribution (based on two-tier RPP prices)			**44.29**			**44.29**	**0.00**	**0.00%**	**35.85%**	**35.46%**
Sub-Total: Distribution (based on TOU prices)			**43.68**			**43.68**	**0.00**	**0.00%**	**35.35%**	**34.96%**
Retail Transmission Rate – Network Service Rate	829	0.0068	5.64	829	0.0068	5.64	0.00	0.00%	4.56%	4.51%
Retail Transmission Rate – Line and Transformation Connection S	829	0.0055	4.56	829	0.0055	4.56	0.00	0.00%	3.69%	3.65%
Sub-Total: Retail Transmission			**10.19**			**10.19**	**0.00**	**0.00%**	**8.25%**	**8.16%**
Sub-Total: Delivery (based on two-tier RPP prices)			**54.49**			**54.49**	**0.00**	**0.00%**	**44.10%**	**43.62%**
Sub-Total: Delivery (based on TOU prices)			**53.87**			**53.87**	**0.00**	**0.00%**	**43.60%**	**43.12%**
Wholesale Market Service Rate	829	0.0036	2.98	829	0.0036	2.98	0.00	0.00%	2.41%	2.39%
Rural Rate Protection Charge	829	0.0003	0.25	829	0.0003	0.25	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	829	0.0000	0.00	829	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.48**			**3.48**	**0.00**	**0.00%**	**2.82%**	**2.79%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**117.67**			**117.67**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	15.30		0.13	15.30	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**132.97**			**132.97**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.41		-0.08	-9.41	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**123.55**			**123.55**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**118.97**			**118.97**	**0.00**	**0.00%**		**95.24%**
HST		0.13	15.47		0.13	15.47	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**134.44**			**134.44**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.52		-0.08	-9.52	0.00	0.00%		-7.62%
Total Amount on TOU			**124.92**			**124.92**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	1,152
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1273
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	26.69%	
Energy Second Tier (kWh)	552	0.090	49.68	552	0.090	49.68	0.00	0.00%	28.70%	
Sub-Total: Energy (RPP)			**95.88**			**95.88**	**0.00**	**0.00%**	**55.39%**	
TOU-Off Peak	749	0.065	48.67	749	0.065	48.67	0.00	0.00%		28.50%
TOU-Mid Peak	196	0.095	18.60	196	0.095	18.60	0.00	0.00%		10.89%
TOU-On Peak	207	0.132	27.37	207	0.132	27.37	0.00	0.00%		16.03%
Sub-Total: Energy (TOU)			**94.65**			**94.65**	0.00	0.00%	**54.68%**	**55.41%**
Service Charge	1	55.26	36.43	1	68.12	36.43	0.00	0.00%	21.05%	21.33%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	1,152	0.0201	0.00	1,152	0.0117	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,152	0.0000	0.01	1,152	0.00001	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.42**			**36.42**	**0.00**	**0.00%**	**21.04%**	**21.32%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.46%	0.46%
Line Losses on Cost of Power (based on two-tier RPP prices)	121	0.0900	10.89	121	0.0900	10.89	0.00	0.00%	6.29%	6.37%
Line Losses on Cost of Power (based on TOU prices)	121	0.0822	9.94	121	0.0822	9.94	0.00	0.00%	5.74%	5.82%
Sub-Total: Distribution (based on two-tier RPP prices)			**48.10**			**48.10**	**0.00**	**0.00%**	**27.79%**	**28.16%**
Sub-Total: Distribution (based on TOU prices)			**47.15**			**47.15**	**0.00**	**0.00%**	**27.24%**	**27.60%**
Retail Transmission Rate – Network Service Rate	1,273	0.0068	8.66	1,273	0.0068	8.66	0.00	0.00%	5.00%	5.07%
Retail Transmission Rate – Line and Transformation Connection S	1,273	0.0055	7.00	1,273	0.0055	7.00	0.00	0.00%	4.04%	4.10%
Sub-Total: Retail Transmission			**15.66**			**15.66**	**0.00**	**0.00%**	**9.05%**	**9.17%**
Sub-Total: Delivery (based on two-tier RPP prices)			**63.75**			**63.75**	**0.00**	**0.00%**	**36.83%**	**37.33%**
Sub-Total: Delivery (based on TOU prices)			**62.81**			**62.81**	**0.00**	**0.00%**	**36.28%**	**36.77%**
Wholesale Market Service Rate	1,273	0.0036	4.58	1,273	0.0036	4.58	0.00	0.00%	2.65%	2.68%
Rural Rate Protection Charge	1,273	0.0003	0.38	1,273	0.0003	0.38	0.00	0.00%	0.22%	0.22%
Ontario Electricity Support Program Charge	1,273	0.0000	0.00	1,273	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.15%
Sub-Total: Regulatory			**5.21**			**5.21**	**0.00**	**0.00%**	**3.01%**	**3.05%**
Debt Retirement Charge (DRC)	1,152	0.000	**0.00**	1,152	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**164.85**			**164.85**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	21.43		0.13	21.43	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**186.28**			**186.28**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.19		-0.08	-13.19	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**173.09**			**173.09**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**162.67**			**162.67**	**0.00**	**0.00%**		**95.24%**
HST		0.13	21.15		0.13	21.15	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**183.82**			**183.82**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.01		-0.08	-13.01	0.00	0.00%		-7.62%
Total Amount on TOU			**170.80**			**170.80**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	R2
Monthly Consumption (kWh)	2300
Peak (kW)	0
Loss factor	1.105
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	2542
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	14.69%	
Energy Second Tier (kWh)	1,700	0.090	153.00	1,700	0.090	153.00	0.00	0.00%	48.64%	
Sub-Total: Energy (RPP)			**199.20**			**199.20**	**0.00**	**0.00%**	**63.33%**	
TOU-Off Peak	1,495	0.065	97.18	1,495	0.065	97.18	0.00	0.00%		32.20%
TOU-Mid Peak	391	0.095	37.15	391	0.095	37.15	0.00	0.00%		12.31%
TOU-On Peak	414	0.132	54.65	414	0.132	54.65	0.00	0.00%		18.11%
Sub-Total: Energy (TOU)			**188.97**			**188.97**	0.00	0.00%	**60.07%**	**62.61%**
Service Charge	1	55.26	36.43	1	68.12	36.43	0.00	0.00%	11.58%	12.07%
Fixed Deferral/Variance Account Rider	1	-0.02	-0.02	1	-0.02	-0.02	0.00	0.00%	-0.01%	-0.01%
Distribution Volumetric Rate	2,300	0.0201	0.00	2,300	0.0117	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,300	0.0000	0.02	2,300	0.00001	0.02	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**36.43**			**36.43**	**0.00**	**0.00%**	**11.58%**	**12.07%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.26%
Line Losses on Cost of Power (based on two-tier RPP prices)	242	0.0900	21.74	242	0.0900	21.74	0.00	0.00%	6.91%	7.20%
Line Losses on Cost of Power (based on TOU prices)	242	0.0822	19.84	242	0.0822	19.84	0.00	0.00%	6.31%	6.57%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.96**			**58.96**	**0.00**	**0.00%**	**18.74%**	**19.53%**
Sub-Total: Distribution (based on TOU prices)			**57.06**			**57.06**	**0.00**	**0.00%**	**18.14%**	**18.91%**
Retail Transmission Rate – Network Service Rate	2,542	0.0068	17.28	2,542	0.0068	17.28	0.00	0.00%	5.49%	5.73%
Retail Transmission Rate – Line and Transformation Connection S	2,542	0.0055	13.98	2,542	0.0055	13.98	0.00	0.00%	4.44%	4.63%
Sub-Total: Retail Transmission			**31.26**			**31.26**	**0.00**	**0.00%**	**9.94%**	**10.36%**
Sub-Total: Delivery (based on two-tier RPP prices)			**90.22**			**90.22**	**0.00**	**0.00%**	**28.68%**	**29.89%**
Sub-Total: Delivery (based on TOU prices)			**88.32**			**88.32**	**0.00**	**0.00%**	**28.08%**	**29.26%**
Wholesale Market Service Rate	2,542	0.0036	9.15	2,542	0.0036	9.15	0.00	0.00%	2.91%	3.03%
Rural Rate Protection Charge	2,542	0.0003	0.76	2,542	0.0003	0.76	0.00	0.00%	0.24%	0.25%
Ontario Electricity Support Program Charge	2,542	0.0000	0.00	2,542	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**10.16**			**10.16**	**0.00**	**0.00%**	**3.23%**	**3.37%**
Debt Retirement Charge (DRC)	2,300	0.000	**0.00**	2,300	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**299.58**			**299.58**	**0.00**	**0.00%**	**95.24%**	
HST		0.13	38.95		0.13	38.95	0.00	0.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**338.52**			**338.52**	**0.00**	**0.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.97		-0.08	-23.97	0.00	0.00%	-7.62%	
Total Amount on Two-Tier RPP			**314.56**			**314.56**	**0.00**	**0.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**287.45**			**287.45**	**0.00**	**0.00%**		**95.24%**
HST		0.13	37.37		0.13	37.37	0.00	0.00%		12.38%
Total Electricity Charge on TOU (including HST)			**324.82**			**324.82**	**0.00**	**0.00%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.00		-0.08	-23.00	0.00	0.00%		-7.62%
Total Amount on TOU			**301.83**			**301.83**	**0.00**	**0.00%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	50
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	55
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	50	0.077	3.85	50	0.077	3.85	0.00	0.00%	5.35%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**3.85**			**3.85**	**0.00**	**0.00%**	**5.35%**	
TOU-Off Peak	33	0.065	2.11	33	0.065	2.11	0.00	0.00%		2.93%
TOU-Mid Peak	9	0.095	0.81	9	0.095	0.81	0.00	0.00%		1.12%
TOU-On Peak	9	0.132	1.19	9	0.132	1.19	0.00	0.00%		1.65%
Sub-Total: Energy (TOU)			**4.11**			**4.11**	0.00	0.00%	**5.71%**	**5.69%**
Service Charge	1	55.37	55.37	1	61.48	61.48	6.11	11.03%	85.50%	85.14%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	50	0.0317	1.59	50	0.0184	0.92	-0.67	-41.96%	1.28%	1.27%
Volumetric Deferral/Variance Account Rider (including CBR Class	50	0.00001	0.00	50	0.00001	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**56.95**			**62.40**	**5.45**	**9.56%**	**86.78%**	**86.42%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.10%	1.09%
Line Losses on Cost of Power (based on two-tier RPP prices)	5	0.0770	0.40	5	0.0770	0.40	0.00	0.00%	0.56%	0.55%
Line Losses on Cost of Power (based on TOU prices)	5	0.0822	0.43	5	0.0822	0.43	0.00	0.00%	0.59%	0.59%
Sub-Total: Distribution (based on two-tier RPP prices)			**58.14**			**63.59**	**5.45**	**9.36%**	**88.43%**	**88.06%**
Sub-Total: Distribution (based on TOU prices)			**58.17**			**63.62**	**5.45**	**9.36%**	**88.47%**	**88.10%**
Retail Transmission Rate – Network Service Rate	55	0.0058	0.32	55	0.0058	0.32	0.00	0.00%	0.45%	0.44%
Retail Transmission Rate – Line and Transformation Connection S	55	0.0047	0.26	55	0.0047	0.26	0.00	0.00%	0.36%	0.36%
Sub-Total: Retail Transmission			**0.58**			**0.58**	**0.00**	**0.00%**	**0.81%**	**0.80%**
Sub-Total: Delivery (based on two-tier RPP prices)			**58.72**			**64.17**	**5.45**	**9.27%**	**89.24%**	**88.87%**
Sub-Total: Delivery (based on TOU prices)			**58.75**			**64.20**	**5.45**	**9.27%**	**89.27%**	**88.90%**
Wholesale Market Service Rate	55	0.0036	0.20	55	0.0036	0.20	0.00	0.00%	0.28%	0.28%
Rural Rate Protection Charge	55	0.0003	0.02	55	0.0003	0.02	0.00	0.00%	0.02%	0.02%
Ontario Electricity Support Program Charge	55	0.0000	0.00	55	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.35%	0.35%
Sub-Total: Regulatory			**0.47**			**0.47**	**0.00**	**0.00%**	**0.65%**	**0.64%**
Debt Retirement Charge (DRC)	50	0.000	**0.00**	50	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**63.04**			**68.48**	**5.45**	**8.64%**	**95.24%**	
HST		0.13	8.20		0.13	8.90	0.71	8.64%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**71.23**			**77.39**	**6.15**	**8.64%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.04		-0.08	-5.48	-0.44	-8.64%	-7.62%	
Total Amount on Two-Tier RPP			**66.19**			**71.91**	**5.72**	**8.64%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**63.32**			**68.77**	**5.45**	**8.60%**		**95.24%**
HST		0.13	8.23		0.13	8.94	0.71	8.60%		12.38%
Total Electricity Charge on TOU (including HST)			**71.56**			**77.71**	**6.15**	**8.60%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.07		-0.08	-5.50	-0.44	-8.60%		-7.62%
Total Amount on TOU			**66.49**			**72.21**	**5.72**	**8.60%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	352
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	389
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	352	0.077	27.10	352	0.077	27.10	0.00	0.00%	24.70%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**27.10**			**27.10**	**0.00**	**0.00%**	**24.70%**	
TOU-Off Peak	229	0.065	14.87	229	0.065	14.87	0.00	0.00%		13.30%
TOU-Mid Peak	60	0.095	5.68	60	0.095	5.68	0.00	0.00%		5.08%
TOU-On Peak	63	0.132	8.36	63	0.132	8.36	0.00	0.00%		7.48%
Sub-Total: Energy (TOU)			**28.92**			**28.92**	0.00	0.00%	**26.35%**	**25.86%**
Service Charge	1	55.37	55.37	1	61.48	61.48	6.11	11.03%	56.02%	54.97%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	352	0.0317	11.16	352	0.0184	6.48	-4.68	-41.96%	5.90%	5.79%
Volumetric Deferral/Variance Account Rider (including CBR Class	352	0.00001	0.00	352	0.00001	0.00	0.00	0.00%	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**66.53**			**67.96**	**1.43**	**2.15%**	**61.93%**	**60.76%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.72%	0.71%
Line Losses on Cost of Power (based on two-tier RPP prices)	37	0.0770	2.82	37	0.0770	2.82	0.00	0.00%	2.57%	2.52%
Line Losses on Cost of Power (based on TOU prices)	37	0.0822	3.01	37	0.0822	3.01	0.00	0.00%	2.74%	2.69%
Sub-Total: Distribution (based on two-tier RPP prices)			**70.14**			**71.57**	**1.43**	**2.04%**	**65.21%**	**63.99%**
Sub-Total: Distribution (based on TOU prices)			**70.33**			**71.76**	**1.43**	**2.03%**	**65.39%**	**64.15%**
Retail Transmission Rate – Network Service Rate	389	0.0058	2.25	389	0.0058	2.25	0.00	0.00%	2.05%	2.02%
Retail Transmission Rate – Line and Transformation Connection S	389	0.0047	1.83	389	0.0047	1.83	0.00	0.00%	1.66%	1.63%
Sub-Total: Retail Transmission			**4.08**			**4.08**	**0.00**	**0.00%**	**3.72%**	**3.65%**
Sub-Total: Delivery (based on two-tier RPP prices)			**74.22**			**75.65**	**1.43**	**1.92%**	**68.93%**	**67.63%**
Sub-Total: Delivery (based on TOU prices)			**74.41**			**75.84**	**1.43**	**1.92%**	**69.10%**	**67.80%**
Wholesale Market Service Rate	389	0.0036	1.40	389	0.0036	1.40	0.00	0.00%	1.27%	1.25%
Rural Rate Protection Charge	389	0.0003	0.12	389	0.0003	0.12	0.00	0.00%	0.11%	0.10%
Ontario Electricity Support Program Charge	389	0.0000	0.00	389	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.23%	0.22%
Sub-Total: Regulatory			**1.77**			**1.77**	**0.00**	**0.00%**	**1.61%**	**1.58%**
Debt Retirement Charge (DRC)	352	0.000	**0.00**	352	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**103.09**			**104.52**	**1.43**	**1.39%**	**95.24%**	
HST		0.13	13.40		0.13	13.59	0.19	1.39%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**116.49**			**118.10**	**1.61**	**1.39%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.25		-0.08	-8.36	-0.11	-1.39%	-7.62%	
Total Amount on Two-Tier RPP			**108.24**			**109.74**	**1.50**	**1.39%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**105.09**			**106.52**	**1.43**	**1.36%**		**95.24%**
HST		0.13	13.66		0.13	13.85	0.19	1.36%		12.38%
Total Electricity Charge on TOU (including HST)			**118.76**			**120.37**	**1.61**	**1.36%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.41		-0.08	-8.52	-0.11	-1.36%		-7.62%
Total Amount on TOU			**110.35**			**111.85**	**1.50**	**1.36%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	Seasonal
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.104
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1104
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.36%	
Energy Second Tier (kWh)	400	0.090	36.00	400	0.090	36.00	0.00	0.00%	18.20%	
Sub-Total: Energy (RPP)			**82.20**			**82.20**	**0.00**	**0.00%**	**41.56%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		21.46%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		8.20%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		12.07%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**41.54%**	**41.73%**
Service Charge	1	55.37	55.37	1	61.48	61.48	6.11	11.03%	31.08%	31.22%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0317	31.70	1,000	0.0184	18.40	-13.30	-41.96%	9.30%	9.34%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.00001	0.01	1,000	0.00001	0.01	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**87.08**			**79.89**	**-7.19**	**-8.26%**	**40.39%**	**40.57%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.40%	0.40%
Line Losses on Cost of Power (based on two-tier RPP prices)	104	0.0900	9.36	104	0.0900	9.36	0.00	0.00%	4.73%	4.75%
Line Losses on Cost of Power (based on TOU prices)	104	0.0822	8.54	104	0.0822	8.54	0.00	0.00%	4.32%	4.34%
Sub-Total: Distribution (based on two-tier RPP prices)			**97.23**			**90.04**	**-7.19**	**-7.39%**	**45.52%**	**45.73%**
Sub-Total: Distribution (based on TOU prices)			**96.41**			**89.22**	**-7.19**	**-7.46%**	**45.11%**	**45.31%**
Retail Transmission Rate – Network Service Rate	1,104	0.0058	6.40	1,104	0.0058	6.40	0.00	0.00%	3.24%	3.25%
Retail Transmission Rate – Line and Transformation Connection S	1,104	0.0047	5.19	1,104	0.0047	5.19	0.00	0.00%	2.62%	2.64%
Sub-Total: Retail Transmission			**11.59**			**11.59**	**0.00**	**0.00%**	**5.86%**	**5.89%**
Sub-Total: Delivery (based on two-tier RPP prices)			**108.82**			**101.63**	**-7.19**	**-6.61%**	**51.38%**	**51.61%**
Sub-Total: Delivery (based on TOU prices)			**108.00**			**100.81**	**-7.19**	**-6.66%**	**50.97%**	**51.20%**
Wholesale Market Service Rate	1,104	0.0036	3.97	1,104	0.0036	3.97	0.00	0.00%	2.01%	2.02%
Rural Rate Protection Charge	1,104	0.0003	0.33	1,104	0.0003	0.33	0.00	0.00%	0.17%	0.17%
Ontario Electricity Support Program Charge	1,104	0.0000	0.00	1,104	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**4.56**			**4.56**	**0.00**	**0.00%**	**2.30%**	**2.31%**
Debt Retirement Charge (DRC)	1,000	0.000	**0.00**	1,000	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**195.58**			**188.39**	**-7.19**	**-3.68%**	**95.24%**	
HST		0.13	25.42		0.13	24.49	-0.93	-3.68%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**221.00**			**212.88**	**-8.12**	**-3.68%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.65		-0.08	-15.07	0.58	3.68%	-7.62%	
Total Amount on Two-Tier RPP			**205.35**			**197.80**	**-7.55**	**-3.68%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**194.72**			**187.53**	**-7.19**	**-3.69%**		**95.24%**
HST		0.13	25.31		0.13	24.38	-0.93	-3.69%		12.38%
Total Electricity Charge on TOU (including HST)			**220.03**			**211.91**	**-8.12**	**-3.69%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-15.58		-0.08	-15.00	0.58	3.69%		-7.62%
Total Amount on TOU			**204.46**			**196.91**	**-7.55**	**-3.69%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1067
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	32.86%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.80%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**45.66%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		23.84%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.11%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.41%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**46.74%**	**46.36%**
Service Charge	1	25.55	25.55	1	26.07	26.07	0.52	2.04%	14.83%	14.71%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0308	30.80	1,000	0.0316	31.60	0.80	2.60%	17.98%	17.83%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.00003	0.0300	1,000	0.00003	0.0300	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**56.39**			**57.71**	**1.32**	**2.34%**	**32.83%**	**32.56%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.45%	0.45%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.03	67	0.0900	6.03	0.00	0.00%	3.43%	3.40%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.50	67	0.0822	5.50	0.00	0.00%	3.13%	3.11%
Sub-Total: Distribution (based on two-tier RPP prices)			**63.21**			**64.53**	**1.32**	**2.09%**	**36.71%**	**36.41%**
Sub-Total: Distribution (based on TOU prices)			**62.68**			**64.00**	**1.32**	**2.11%**	**36.41%**	**36.12%**
Retail Transmission Rate – Network Service Rate	1,067	0.0058	6.19	1,067	0.0058	6.19	0.00	0.00%	3.52%	3.49%
Retail Transmission Rate – Line and Transformation Connection S	1,067	0.0047	5.01	1,067	0.0047	5.01	0.00	0.00%	2.85%	2.83%
Sub-Total: Retail Transmission			**11.20**			**11.20**	**0.00**	**0.00%**	**6.37%**	**6.32%**
Sub-Total: Delivery (based on two-tier RPP prices)			**74.41**			**75.73**	**1.32**	**1.77%**	**43.09%**	**42.73%**
Sub-Total: Delivery (based on TOU prices)			**73.89**			**75.21**	**1.32**	**1.79%**	**42.79%**	**42.44%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.19%	2.17%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.51%**	**2.49%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.98%**	**3.95%**
Total Electricty Charge on Two-Tier RPP			**166.07**			**167.39**	**1.32**	**0.79%**	**95.24%**	
HST		0.13	21.59		0.13	21.76	0.17	0.79%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**187.66**			**189.15**	**1.49**	**0.79%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.29		-0.08	-13.39	-0.11	-0.79%	-7.62%	
Total Amount on Two-Tier RPP			**174.38**			**175.76**	**1.39**	**0.79%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**167.46**			**168.78**	**1.32**	**0.79%**		**95.24%**
HST		0.13	21.77		0.13	21.94	0.17	0.79%		12.38%
Total Electricity Charge on TOU (including HST)			**189.23**			**190.72**	**1.49**	**0.79%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.40		-0.08	-13.50	-0.11	-0.79%		-7.62%
Total Amount on TOU			**175.83**			**177.22**	**1.39**	**0.79%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2134
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.33%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	33.75%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**51.08%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		25.92%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		9.91%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		14.58%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**49.30%**	**50.41%**
Service Charge	1	25.55	25.55	1	26.07	26.07	0.52	2.04%	7.82%	8.00%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0308	61.60	2,000	0.0316	63.20	1.60	2.60%	18.96%	19.39%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.00003	0.0600	2,000	0.00003	0.0600	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**87.22**			**89.34**	**2.12**	**2.43%**	**26.81%**	**27.41%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.24%
Line Losses on Cost of Power (based on two-tier RPP prices)	134	0.0900	12.06	134	0.0900	12.06	0.00	0.00%	3.62%	3.70%
Line Losses on Cost of Power (based on TOU prices)	134	0.0822	11.01	134	0.0822	11.01	0.00	0.00%	3.30%	3.38%
Sub-Total: Distribution (based on two-tier RPP prices)			**100.07**			**102.19**	**2.12**	**2.12%**	**30.66%**	**31.35%**
Sub-Total: Distribution (based on TOU prices)			**99.02**			**101.14**	**2.12**	**2.14%**	**30.35%**	**31.03%**
Retail Transmission Rate – Network Service Rate	2,134	0.0058	12.38	2,134	0.0058	12.38	0.00	0.00%	3.71%	3.80%
Retail Transmission Rate – Line and Transformation Connection S	2,134	0.0047	10.03	2,134	0.0047	10.03	0.00	0.00%	3.01%	3.08%
Sub-Total: Retail Transmission			**22.41**			**22.41**	**0.00**	**0.00%**	**6.72%**	**6.87%**
Sub-Total: Delivery (based on two-tier RPP prices)			**122.48**			**124.60**	**2.12**	**1.73%**	**37.38%**	**38.22%**
Sub-Total: Delivery (based on TOU prices)			**121.42**			**123.54**	**2.12**	**1.75%**	**37.07%**	**37.90%**
Wholesale Market Service Rate	2,134	0.0036	7.68	2,134	0.0036	7.68	0.00	0.00%	2.31%	2.36%
Rural Rate Protection Charge	2,134	0.0003	0.64	2,134	0.0003	0.64	0.00	0.00%	0.19%	0.20%
Ontario Electricity Support Program Charge	2,134	0.0000	0.00	2,134	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.57%**	**2.63%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.20%**	**4.30%**
Total Electricty Charge on Two-Tier RPP			**315.30**			**317.42**	**2.12**	**0.67%**	**95.24%**	
HST		0.13	40.99		0.13	41.26	0.28	0.67%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**356.29**			**358.68**	**2.40**	**0.67%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-25.22		-0.08	-25.39	-0.17	-0.67%	-7.62%	
Total Amount on Two-Tier RPP			**331.06**			**333.29**	**2.23**	**0.67%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**308.32**			**310.44**	**2.12**	**0.69%**		**95.24%**
HST		0.13	40.08		0.13	40.36	0.28	0.69%		12.38%
Total Electricity Charge on TOU (including HST)			**348.40**			**350.79**	**2.40**	**0.69%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.67		-0.08	-24.83	-0.17	-0.69%		-7.62%
Total Amount on TOU			**323.73**			**325.96**	**2.23**	**0.69%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	2,759
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2943.853
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.75%	
Energy Second Tier (kWh)	2,009	0.090	180.81	2,009	0.090	180.81	0.00	0.00%	39.93%	
Sub-Total: Energy (RPP)			**238.56**			**238.56**	**0.00**	**0.00%**	**52.68%**	
TOU-Off Peak	1,793	0.065	116.57	1,793	0.065	116.57	0.00	0.00%		26.56%
TOU-Mid Peak	469	0.095	44.56	469	0.095	44.56	0.00	0.00%		10.15%
TOU-On Peak	497	0.132	65.55	497	0.132	65.55	0.00	0.00%		14.94%
Sub-Total: Energy (TOU)			**226.68**			**226.68**	0.00	0.00%	**50.06%**	**51.65%**
Service Charge	1	25.55	25.55	1	26.07	26.07	0.52	2.04%	5.76%	5.94%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,759	0.0308	84.98	2,759	0.0316	87.18	2.21	2.60%	19.25%	19.87%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,759	0.00003	0.0828	2,759	0.00003	0.0828	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**110.62**			**113.35**	**2.73**	**2.47%**	**25.03%**	**25.83%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.17%	0.18%
Line Losses on Cost of Power (based on two-tier RPP prices)	185	0.0900	16.64	185	0.0900	16.64	0.00	0.00%	3.67%	3.79%
Line Losses on Cost of Power (based on TOU prices)	185	0.0822	15.19	185	0.0822	15.19	0.00	0.00%	3.35%	3.46%
Sub-Total: Distribution (based on two-tier RPP prices)			**128.04**			**130.77**	**2.73**	**2.13%**	**28.88%**	**29.80%**
Sub-Total: Distribution (based on TOU prices)			**126.60**			**129.32**	**2.73**	**2.15%**	**28.56%**	**29.47%**
Retail Transmission Rate – Network Service Rate	2,944	0.0058	17.07	2,944	0.0058	17.07	0.00	0.00%	3.77%	3.89%
Retail Transmission Rate – Line and Transformation Connection S	2,944	0.0047	13.84	2,944	0.0047	13.84	0.00	0.00%	3.06%	3.15%
Sub-Total: Retail Transmission			**30.91**			**30.91**	**0.00**	**0.00%**	**6.83%**	**7.04%**
Sub-Total: Delivery (based on two-tier RPP prices)			**158.96**			**161.68**	**2.73**	**1.72%**	**35.70%**	**36.84%**
Sub-Total: Delivery (based on TOU prices)			**157.51**			**160.23**	**2.73**	**1.73%**	**35.38%**	**36.51%**
Wholesale Market Service Rate	2,944	0.0036	10.60	2,944	0.0036	10.60	0.00	0.00%	2.34%	2.41%
Rural Rate Protection Charge	2,944	0.0003	0.88	2,944	0.0003	0.88	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,944	0.0000	0.00	2,944	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.73**			**11.73**	**0.00**	**0.00%**	**2.59%**	**2.67%**
Debt Retirement Charge (DRC)	2,759	0.007	**19.31**	2,759	0.007	**19.31**	**0.00**	**0.00%**	**4.26%**	**4.40%**
Total Electricty Charge on Two-Tier RPP			**428.56**			**431.29**	**2.73**	**0.64%**	**95.24%**	
HST		0.13	55.71		0.13	56.07	0.35	0.64%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**484.27**			**487.35**	**3.08**	**0.64%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-34.28		-0.08	-34.50	-0.22	-0.64%	-7.62%	
Total Amount on Two-Tier RPP			**449.99**			**452.85**	**2.86**	**0.64%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**415.23**			**417.96**	**2.73**	**0.66%**		**95.24%**
HST		0.13	53.98		0.13	54.33	0.35	0.66%		12.38%
Total Electricity Charge on TOU (including HST)			**469.21**			**472.29**	**3.08**	**0.66%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-33.22		-0.08	-33.44	-0.22	-0.66%		-7.62%
Total Amount on TOU			**435.99**			**438.85**	**2.86**	**0.66%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	UGe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.067
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16005
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.43%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	53.86%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**56.29%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		28.05%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		10.72%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		15.77%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**51.76%**	**54.54%**
Service Charge	1	25.55	25.55	1	26.07	26.07	0.52	2.04%	1.09%	1.15%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0308	462.00	15,000	0.0316	474.00	12.00	2.60%	19.91%	20.98%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.00003	0.4500	15,000	0.00003	0.4500	0.00	0.00%	0.02%	0.02%
Sub-Total: Distribution (excluding pass through)			**488.01**			**500.53**	**12.52**	**2.57%**	**21.02%**	**22.15%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,005	0.0900	90.45	1,005	0.0900	90.45	0.00	0.00%	3.80%	4.00%
Line Losses on Cost of Power (based on TOU prices)	1,005	0.0822	82.57	1,005	0.0822	82.57	0.00	0.00%	3.47%	3.65%
Sub-Total: Distribution (based on two-tier RPP prices)			**579.25**			**591.77**	**12.52**	**2.16%**	**24.85%**	**26.19%**
Sub-Total: Distribution (based on TOU prices)			**571.37**			**583.89**	**12.52**	**2.19%**	**24.52%**	**25.84%**
Retail Transmission Rate – Network Service Rate	16,005	0.0058	92.83	16,005	0.0058	92.83	0.00	0.00%	3.90%	4.11%
Retail Transmission Rate – Line and Transformation Connection S	16,005	0.0047	75.22	16,005	0.0047	75.22	0.00	0.00%	3.16%	3.33%
Sub-Total: Retail Transmission			**168.05**			**168.05**	**0.00**	**0.00%**	**7.06%**	**7.44%**
Sub-Total: Delivery (based on two-tier RPP prices)			**747.30**			**759.82**	**12.52**	**1.68%**	**31.91%**	**33.63%**
Sub-Total: Delivery (based on TOU prices)			**739.42**			**751.94**	**12.52**	**1.69%**	**31.58%**	**33.28%**
Wholesale Market Service Rate	16,005	0.0036	57.62	16,005	0.0036	57.62	0.00	0.00%	2.42%	2.55%
Rural Rate Protection Charge	16,005	0.0003	4.80	16,005	0.0003	4.80	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	16,005	0.0000	0.00	16,005	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.67**			**62.67**	**0.00**	**0.00%**	**2.63%**	**2.77%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.41%**	**4.65%**
Total Electricty Charge on Two-Tier RPP			**2,255.22**			**2,267.74**	**12.52**	**0.56%**	**95.24%**	
HST		0.13	293.18		0.13	294.81	1.63	0.56%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,548.40**			**2,562.55**	**14.15**	**0.56%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-180.42		-0.08	-181.42	-1.00	-0.56%	-7.62%	
Total Amount on Two-Tier RPP			**2,367.98**			**2,381.13**	**13.15**	**0.56%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**2,139.49**			**2,152.01**	**12.52**	**0.59%**		**95.24%**
HST		0.13	278.13		0.13	279.76	1.63	0.59%		12.38%
Total Electricity Charge on TOU (including HST)			**2,417.62**			**2,431.77**	**14.15**	**0.59%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-171.16		-0.08	-172.16	-1.00	-0.59%		-7.62%
Total Amount on TOU			**2,246.47**			**2,259.61**	**13.15**	**0.59%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1096
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	26.05%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	10.15%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**36.20%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		18.95%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		7.25%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		10.66%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**37.06%**	**36.86%**
Service Charge	1	31.38	31.38	1	31.94	31.94	0.56	1.78%	14.41%	14.33%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0652	65.20	1,000	0.0670	67.00	1.80	2.76%	30.22%	30.06%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.00002	0.0200	1,000	0.00002	0.0200	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**96.60**			**98.96**	**2.36**	**2.44%**	**44.64%**	**44.40%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.36%	0.35%
Line Losses on Cost of Power (based on two-tier RPP prices)	96	0.0900	8.64	96	0.0900	8.64	0.00	0.00%	3.90%	3.88%
Line Losses on Cost of Power (based on TOU prices)	96	0.0822	7.89	96	0.0822	7.89	0.00	0.00%	3.56%	3.54%
Sub-Total: Distribution (based on two-tier RPP prices)			**106.03**			**108.39**	**2.36**	**2.23%**	**48.90%**	**48.63%**
Sub-Total: Distribution (based on TOU prices)			**105.28**			**107.64**	**2.36**	**2.24%**	**48.56%**	**48.29%**
Retail Transmission Rate – Network Service Rate	1,096	0.0055	6.03	1,096	0.0055	6.03	0.00	0.00%	2.72%	2.70%
Retail Transmission Rate – Line and Transformation Connection S	1,096	0.0045	4.93	1,096	0.0045	4.93	0.00	0.00%	2.22%	2.21%
Sub-Total: Retail Transmission			**10.96**			**10.96**	**0.00**	**0.00%**	**4.94%**	**4.92%**
Sub-Total: Delivery (based on two-tier RPP prices)			**116.99**			**119.35**	**2.36**	**2.02%**	**53.84%**	**53.55%**
Sub-Total: Delivery (based on TOU prices)			**116.24**			**118.60**	**2.36**	**2.03%**	**53.50%**	**53.21%**
Wholesale Market Service Rate	1,096	0.0036	3.95	1,096	0.0036	3.95	0.00	0.00%	1.78%	1.77%
Rural Rate Protection Charge	1,096	0.0003	0.33	1,096	0.0003	0.33	0.00	0.00%	0.15%	0.15%
Ontario Electricity Support Program Charge	1,096	0.0000	0.00	1,096	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.11%	0.11%
Sub-Total: Regulatory			**4.52**			**4.52**	**0.00**	**0.00%**	**2.04%**	**2.03%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.16%**	**3.14%**
Total Electricty Charge on Two-Tier RPP			**208.77**			**211.13**	**2.36**	**1.13%**	**95.24%**	
HST		0.13	27.14		0.13	27.45	0.31	1.13%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**235.91**			**238.57**	**2.67**	**1.13%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.70		-0.08	-16.89	-0.19	-1.13%	-7.62%	
Total Amount on Two-Tier RPP			**219.20**			**221.68**	**2.48**	**1.13%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**209.92**			**212.28**	**2.36**	**1.12%**		**95.24%**
HST		0.13	27.29		0.13	27.60	0.31	1.12%		12.38%
Total Electricity Charge on TOU (including HST)			**237.21**			**239.88**	**2.67**	**1.12%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-16.79		-0.08	-16.98	-0.19	-1.12%		-7.62%
Total Amount on TOU			**220.42**			**222.90**	**2.48**	**1.12%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2192
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	13.78%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	26.85%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**40.64%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		20.55%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		7.86%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		11.56%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**39.22%**	**39.96%**
Service Charge	1	31.38	31.38	1	31.94	31.94	0.56	1.78%	7.62%	7.77%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0652	130.40	2,000	0.0670	134.00	3.60	2.76%	31.98%	32.59%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.00002	0.0400	2,000	0.00002	0.0400	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**161.82**			**165.98**	**4.16**	**2.57%**	**39.62%**	**40.37%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	192	0.0900	17.28	192	0.0900	17.28	0.00	0.00%	4.12%	4.20%
Line Losses on Cost of Power (based on TOU prices)	192	0.0822	15.77	192	0.0822	15.77	0.00	0.00%	3.77%	3.84%
Sub-Total: Distribution (based on two-tier RPP prices)			**179.89**			**184.05**	**4.16**	**2.31%**	**43.93%**	**44.76%**
Sub-Total: Distribution (based on TOU prices)			**178.39**			**182.55**	**4.16**	**2.33%**	**43.57%**	**44.40%**
Retail Transmission Rate – Network Service Rate	2,192	0.0055	12.06	2,192	0.0055	12.06	0.00	0.00%	2.88%	2.93%
Retail Transmission Rate – Line and Transformation Connection S	2,192	0.0045	9.86	2,192	0.0045	9.86	0.00	0.00%	2.35%	2.40%
Sub-Total: Retail Transmission			**21.92**			**21.92**	**0.00**	**0.00%**	**5.23%**	**5.33%**
Sub-Total: Delivery (based on two-tier RPP prices)			**201.81**			**205.97**	**4.16**	**2.06%**	**49.16%**	**50.09%**
Sub-Total: Delivery (based on TOU prices)			**200.31**			**204.47**	**4.16**	**2.08%**	**48.80%**	**49.73%**
Wholesale Market Service Rate	2,192	0.0036	7.89	2,192	0.0036	7.89	0.00	0.00%	1.88%	1.92%
Rural Rate Protection Charge	2,192	0.0003	0.66	2,192	0.0003	0.66	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,192	0.0000	0.00	2,192	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.80**			**8.80**	**0.00**	**0.00%**	**2.10%**	**2.14%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**3.34%**	**3.40%**
Total Electricty Charge on Two-Tier RPP			**394.86**			**399.02**	**4.16**	**1.05%**	**95.24%**	
HST		0.13	51.33		0.13	51.87	0.54	1.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**446.19**			**450.89**	**4.70**	**1.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-31.59		-0.08	-31.92	-0.33	-1.05%	-7.62%	
Total Amount on Two-Tier RPP			**414.60**			**418.97**	**4.37**	**1.05%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**387.43**			**391.59**	**4.16**	**1.07%**		**95.24%**
HST		0.13	50.37		0.13	50.91	0.54	1.07%		12.38%
Total Electricity Charge on TOU (including HST)			**437.79**			**442.49**	**4.70**	**1.07%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.99		-0.08	-31.33	-0.33	-1.07%		-7.62%
Total Amount on TOU			**406.80**			**411.16**	**4.37**	**1.07%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	1,982
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2172.272
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	13.90%	
Energy Second Tier (kWh)	1,232	0.090	110.88	1,232	0.090	110.88	0.00	0.00%	26.69%	
Sub-Total: Energy (RPP)			**168.63**			**168.63**	**0.00**	**0.00%**	**40.59%**	
TOU-Off Peak	1,288	0.065	83.74	1,288	0.065	83.74	0.00	0.00%		20.54%
TOU-Mid Peak	337	0.095	32.01	337	0.095	32.01	0.00	0.00%		7.85%
TOU-On Peak	357	0.132	47.09	357	0.132	47.09	0.00	0.00%		11.55%
Sub-Total: Energy (TOU)			**162.84**			**162.84**	0.00	0.00%	**39.20%**	**39.93%**
Service Charge	1	31.38	31.38	1	31.94	31.94	0.56	1.78%	7.69%	7.83%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	1,982	0.0652	129.23	1,982	0.0670	132.79	3.57	2.76%	31.97%	32.57%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,982	0.00002	0.0396	1,982	0.00002	0.0396	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**160.65**			**164.78**	**4.13**	**2.57%**	**39.66%**	**40.41%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	190	0.0900	17.12	190	0.0900	17.12	0.00	0.00%	4.12%	4.20%
Line Losses on Cost of Power (based on TOU prices)	190	0.0822	15.63	190	0.0822	15.63	0.00	0.00%	3.76%	3.83%
Sub-Total: Distribution (based on two-tier RPP prices)			**178.56**			**182.69**	**4.13**	**2.31%**	**43.98%**	**44.80%**
Sub-Total: Distribution (based on TOU prices)			**177.07**			**181.20**	**4.13**	**2.33%**	**43.62%**	**44.44%**
Retail Transmission Rate – Network Service Rate	2,172	0.0055	11.95	2,172	0.0055	11.95	0.00	0.00%	2.88%	2.93%
Retail Transmission Rate – Line and Transformation Connection S	2,172	0.0045	9.78	2,172	0.0045	9.78	0.00	0.00%	2.35%	2.40%
Sub-Total: Retail Transmission			**21.72**			**21.72**	**0.00**	**0.00%**	**5.23%**	**5.33%**
Sub-Total: Delivery (based on two-tier RPP prices)			**200.29**			**204.41**	**4.13**	**2.06%**	**49.21%**	**50.13%**
Sub-Total: Delivery (based on TOU prices)			**198.79**			**202.92**	**4.13**	**2.08%**	**48.85%**	**49.76%**
Wholesale Market Service Rate	2,172	0.0036	7.82	2,172	0.0036	7.82	0.00	0.00%	1.88%	1.92%
Rural Rate Protection Charge	2,172	0.0003	0.65	2,172	0.0003	0.65	0.00	0.00%	0.16%	0.16%
Ontario Electricity Support Program Charge	2,172	0.0000	0.00	2,172	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**8.72**			**8.72**	**0.00**	**0.00%**	**2.10%**	**2.14%**
Debt Retirement Charge (DRC)	1,982	0.007	**13.87**	1,982	0.007	**13.87**	**0.00**	**0.00%**	**3.34%**	**3.40%**
Total Electricty Charge on Two-Tier RPP			**391.51**			**395.64**	**4.13**	**1.05%**	**95.24%**	
HST		0.13	50.90		0.13	51.43	0.54	1.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**442.41**			**447.07**	**4.66**	**1.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-31.32		-0.08	-31.65	-0.33	-1.05%	-7.62%	
Total Amount on Two-Tier RPP			**411.09**			**415.42**	**4.33**	**1.05%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**384.23**			**388.36**	**4.13**	**1.07%**		**95.24%**
HST		0.13	49.95		0.13	50.49	0.54	1.07%		12.38%
Total Electricity Charge on TOU (including HST)			**434.18**			**438.84**	**4.66**	**1.07%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.74		-0.08	-31.07	-0.33	-1.07%		-7.62%
Total Amount on TOU			**403.44**			**407.78**	**4.33**	**1.07%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	GSe
Monthly Consumption (kWh)	15,000
Peak (kW)	0
Loss factor	1.096
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16440
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	1.94%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	42.98%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**44.92%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		22.17%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		8.47%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		12.47%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**41.30%**	**43.11%**
Service Charge	1	31.38	31.38	1	31.94	31.94	0.56	1.78%	1.07%	1.12%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0652	978.00	15,000	0.0670	1,005.00	27.00	2.76%	33.68%	35.16%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.00002	0.3000	15,000	0.00002	0.3000	0.00	0.00%	0.01%	0.01%
Sub-Total: Distribution (excluding pass through)			**1,009.68**			**1,037.24**	**27.56**	**2.73%**	**34.76%**	**36.28%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.03%	0.03%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,440	0.0900	129.60	1,440	0.0900	129.60	0.00	0.00%	4.34%	4.53%
Line Losses on Cost of Power (based on TOU prices)	1,440	0.0822	118.31	1,440	0.0822	118.31	0.00	0.00%	3.97%	4.14%
Sub-Total: Distribution (based on two-tier RPP prices)			**1,140.07**			**1,167.63**	**27.56**	**2.42%**	**39.13%**	**40.85%**
Sub-Total: Distribution (based on TOU prices)			**1,128.78**			**1,156.34**	**27.56**	**2.44%**	**38.75%**	**40.45%**
Retail Transmission Rate – Network Service Rate	16,440	0.0055	90.42	16,440	0.0055	90.42	0.00	0.00%	3.03%	3.16%
Retail Transmission Rate – Line and Transformation Connection S	16,440	0.0045	73.98	16,440	0.0045	73.98	0.00	0.00%	2.48%	2.59%
Sub-Total: Retail Transmission			**164.40**			**164.40**	**0.00**	**0.00%**	**5.51%**	**5.75%**
Sub-Total: Delivery (based on two-tier RPP prices)			**1,304.47**			**1,332.03**	**27.56**	**2.11%**	**44.64%**	**46.60%**
Sub-Total: Delivery (based on TOU prices)			**1,293.18**			**1,320.74**	**27.56**	**2.13%**	**44.26%**	**46.20%**
Wholesale Market Service Rate	16,440	0.0036	59.18	16,440	0.0036	59.18	0.00	0.00%	1.98%	2.07%
Rural Rate Protection Charge	16,440	0.0003	4.93	16,440	0.0003	4.93	0.00	0.00%	0.17%	0.17%
Ontario Electricity Support Program Charge	16,440	0.0000	0.00	16,440	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**64.37**			**64.37**	**0.00**	**0.00%**	**2.16%**	**2.25%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.52%**	**3.67%**
Total Electricty Charge on Two-Tier RPP			**2,814.09**			**2,841.65**	**27.56**	**0.98%**	**95.24%**	
HST		0.13	365.83		0.13	369.41	3.58	0.98%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**3,179.92**			**3,211.06**	**31.14**	**0.98%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-225.13		-0.08	-227.33	-2.20	-0.98%	-7.62%	
Total Amount on Two-Tier RPP			**2,954.79**			**2,983.73**	**28.94**	**0.98%**	**100.00%**	
Total Electricity Charge on TOU (before HST)			**2,694.95**			**2,722.51**	**27.56**	**1.02%**		**95.24%**
HST		0.13	350.34		0.13	353.93	3.58	1.02%		12.38%
Total Electricity Charge on TOU (including HST)			**3,045.29**			**3,076.43**	**31.14**	**1.02%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-215.60		-0.08	-217.80	-2.20	-1.02%		-7.62%
Total Amount on TOU			**2,829.70**			**2,858.63**	**28.94**	**1.02%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.050
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,750	0.077	1,212.75	15,750	0.077	1,212.75	0.00	0.00%	45.23%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,212.75**			**1,212.75**	**0.00**	**0.00%**	**45.23%**
Service Charge	1	106.68	106.68	1	108.5	108.50	1.82	1.71%	4.05%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	10.6761	640.57	60	10.8703	652.22	11.65	1.82%	24.33%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.01118	0.67	60	0.01118	0.67	0.00	0.00%	0.03%
Volumetric Global Adjustment Account Rider	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**747.93**			**761.41**	**13.47**	**1.80%**	**28.40%**
Retail Transmission Rate – Network Service Rate	60	2.1349	128.09	60	2.1349	128.09	0.00	0.00%	4.78%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.7285	103.71	60	1.7285	103.71	0.00	0.00%	3.87%
Sub-Total: Retail Transmission			**231.80**			**231.80**	**0.00**	**0.00%**	**8.65%**
Sub-Total: Delivery			**979.74**			**993.21**	**13.47**	**1.38%**	**37.05%**
Wholesale Market Service Rate	15,750	0.0036	56.70	15,750	0.0036	56.70	0.00	0.00%	2.11%
Rural Rate Protection Charge	15,750	0.0003	4.73	15,750	0.0003	4.73	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	15,750	0.0000	0.00	15,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.68**			**61.68**	**0.00**	**0.00%**	**2.30%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.92%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,359.16**			**2,372.64**	**13.47**	**0.57%**	**88.50%**
HST		0.13	306.69		0.13	308.44	1.75	0.57%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,665.86**			**2,681.08**	**15.22**	**0.57%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,665.86**			**2,681.08**	**15.22**	**0.57%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	50,525
Peak (kW)	138
Loss factor	1.050
Load factor	50%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	53,051
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	53,051	0.077	4,084.95	53,051	0.077	4,084.95	0.00	0.00%	53.25%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,084.95**			**4,084.95**	**0.00**	**0.00%**	**53.25%**
Service Charge	1	106.68	106.68	1	108.5	108.50	1.82	1.71%	1.41%
Fixed Deferral/Variance Account Rider	1	0.02	0.02	1	0.02	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	138	10.6761	1,473.30	138	10.8703	1,500.10	26.80	1.82%	19.55%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	138	0.01118	1.54	138	0.01118	1.54	0.00	0.00%	0.02%
Volumetric Global Adjustment Account Rider	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,581.54**			**1,610.16**	**28.62**	**1.81%**	**20.99%**
Retail Transmission Rate – Network Service Rate	138	2.1349	294.62	138	2.1349	294.62	0.00	0.00%	3.84%
Retail Transmission Rate – Line and Transformation Connection Service Rate	138	1.7285	238.53	138	1.7285	238.53	0.00	0.00%	3.11%
Sub-Total: Retail Transmission			**533.15**			**533.15**	**0.00**	**0.00%**	**6.95%**
Sub-Total: Delivery			**2,114.69**			**2,143.31**	**28.62**	**1.35%**	**27.94%**
Wholesale Market Service Rate	53,051	0.0036	190.98	53,051	0.0036	190.98	0.00	0.00%	2.49%
Rural Rate Protection Charge	53,051	0.0003	15.92	53,051	0.0003	15.92	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	53,051	0.0000	0.00	53,051	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**207.15**			**207.15**	**0.00**	**0.00%**	**2.70%**
Debt Retirement Charge (DRC)	50,525	0.007	**353.68**	50,525	0.007	**353.68**	**0.00**	**0.00%**	**4.61%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,760.46**			**6,789.08**	**28.62**	**0.42%**	**88.50%**
HST		0.13	878.86		0.13	882.58	3.72	0.42%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,639.32**			**7,671.66**	**32.34**	**0.42%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,639.32**			**7,671.66**	**32.34**	**0.42%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	UGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.050
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,750
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	183,750	0.077	14,148.75	183,750	0.077	14,148.75	0.00	0.00%	53.12%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,148.75**			**14,148.75**	**0.00**	**0.00%**	**53.12%**
Service Charge	1	106.68	106.68	1	108.50	108.50	1.82	1.71%	0.41%
Fixed Deferral/Variance Account Rider	1	0.018	0.02	1	0.018	0.02	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	10.6761	5,338.05	500	10.8703	5,435.15	97.10	1.82%	20.41%
Volumetric Global Adjustment Account Rider	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.01118	5.59	500	0.01118	5.59	0.00	0.00%	0.02%
Sub-Total: Distribution			**5,450.34**			**5,549.26**	**98.92**	**1.81%**	**20.83%**
Retail Transmission Rate – Network Service Rate	500	2.1349	1,067.45	500	2.1349	1,067.45	0.00	0.00%	4.01%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.7285	864.25	500	1.7285	864.25	0.00	0.00%	3.24%
Sub-Total: Retail Transmission			**1,931.70**			**1,931.70**	**0.00**	**0.00%**	**7.25%**
Sub-Total: Delivery			**7,382.04**			**7,480.96**	**98.92**	**1.34%**	**28.09%**
Wholesale Market Service Rate	183,750	0.0036	661.50	183,750	0.0036	661.50	0.00	0.00%	2.48%
Rural Rate Protection Charge	183,750	0.0003	55.13	183,750	0.0003	55.13	0.00	0.00%	0.21%
Ontario Electricity Support Program Charge	183,750	0.0000	0.00	183,750	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**716.88**			**716.88**	**0.00**	**0.00%**	**2.69%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**4.60%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,472.66**			**23,571.58**	**98.92**	**0.42%**	**88.50%**
HST		0.13	3,051.45		0.13	3,064.31	12.86	0.42%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,524.11**			**26,635.89**	**111.78**	**0.42%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,524.11**			**26,635.89**	**111.78**	**0.42%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.061
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,915
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,915	0.077	1,225.46	15,915	0.077	1,225.46	0.00	0.00%	38.59%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,225.46**			**1,225.46**	**0.00**	**0.00%**	**38.59%**
Service Charge	1	107.59	107.59	1	109.21	109.21	1.62	1.51%	3.44%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	60	18.5312	1,111.87	60	18.9196	1,135.18	23.30	2.10%	35.74%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.00516	0.31	60	0.0052	0.31	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,219.76**			**1,244.69**	**24.92**	**2.04%**	**39.19%**
Retail Transmission Rate – Network Service Rate	60	1.5908	95.45	60	1.5908	95.45	0.00	0.00%	3.01%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.2918	77.51	60	1.2918	77.51	0.00	0.00%	2.44%
Sub-Total: Retail Transmission			**172.96**			**172.96**	**0.00**	**0.00%**	**5.45%**
Sub-Total: Delivery			**1,392.72**			**1,417.64**	**24.92**	**1.79%**	**44.64%**
Wholesale Market Service Rate	15,915	0.0036	57.29	15,915	0.0036	57.29	0.00	0.00%	1.80%
Rural Rate Protection Charge	15,915	0.0003	4.77	15,915	0.0003	4.77	0.00	0.00%	0.15%
Ontario Electricity Support Program Charge	15,915	0.0000	0.00	15,915	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.32**			**62.32**	**0.00**	**0.00%**	**1.96%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**3.31%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,785.49**			**2,810.42**	**24.92**	**0.89%**	**88.50%**
HST		0.13	362.11		0.13	365.35	3.24	0.89%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**3,147.61**			**3,175.77**	**28.16**	**0.89%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**3,147.61**			**3,175.77**	**28.16**	**0.89%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	36,104
Peak (kW)	128
Loss factor	1.061
Load factor	39%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	38,306
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	38,306	0.077	2,949.59	38,306	0.077	2,949.59	0.00	0.00%	41.75%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**2,949.59**			**2,949.59**	**0.00**	**0.00%**	**41.75%**
Service Charge	1	107.59	107.59	1	109.21	109.21	1.62	1.51%	1.55%
Fixed Deferral/Variance Account Rider	1	-0.01	-0.01	1	-0.01	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	128	18.5312	2,371.99	128	18.9196	2,421.71	49.72	2.10%	34.28%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	128	0.00516	0.66	128	0.00516	0.66	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,480.24**			**2,531.57**	**51.34**	**2.07%**	**35.83%**
Retail Transmission Rate – Network Service Rate	128	1.5908	203.62	128	1.5908	203.62	0.00	0.00%	2.88%
Retail Transmission Rate – Line and Transformation Connection Service Rate	128	1.2918	165.35	128	1.2918	165.35	0.00	0.00%	2.34%
Sub-Total: Retail Transmission			**368.97**			**368.97**	**0.00**	**0.00%**	**5.22%**
Sub-Total: Delivery			**2,849.21**			**2,900.54**	**51.34**	**1.80%**	**41.05%**
Wholesale Market Service Rate	38,306	0.0036	137.90	38,306	0.0036	137.90	0.00	0.00%	1.95%
Rural Rate Protection Charge	38,306	0.0003	11.49	38,306	0.0003	11.49	0.00	0.00%	0.16%
Ontario Electricity Support Program Charge	38,306	0.0000	0.00	38,306	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**149.64**			**149.64**	**0.00**	**0.00%**	**2.12%**
Debt Retirement Charge (DRC)	36,104	0.007	**252.73**	36,104	0.007	**252.73**	**0.00**	**0.00%**	**3.58%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,201.17**			**6,252.50**	**51.34**	**0.83%**	**88.50%**
HST		0.13	806.15		0.13	812.83	6.67	0.83%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,007.32**			**7,065.33**	**58.01**	**0.83%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,007.32**			**7,065.33**	**58.01**	**0.83%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	GSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.061
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	185,675
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	185,675	0.077	14,296.98	185,675	0.077	14,296.98	0.00	0.00%	46.41%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,296.98**			**14,296.98**	**0.00**	**0.00%**	**46.41%**
Service Charge	1	107.59	107.59	1	109.21	109.21	1.62	1.51%	0.35%
Fixed Deferral/Variance Account Rider	1	-0.009	-0.01	1	-0.009	-0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	500	18.5312	9,265.60	500	18.9196	9,459.80	194.20	2.10%	30.71%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.00516	2.58	500	0.00516	2.58	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**9,375.76**			**9,571.58**	**195.82**	**2.09%**	**31.07%**
Retail Transmission Rate – Network Service Rate	500	1.5908	795.40	500	1.5908	795.40	0.00	0.00%	2.58%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.2918	645.90	500	1.2918	645.90	0.00	0.00%	2.10%
Sub-Total: Retail Transmission			**1,441.30**			**1,441.30**	**0.00**	**0.00%**	**4.68%**
Sub-Total: Delivery			**10,817.06**			**11,012.88**	**195.82**	**1.81%**	**35.75%**
Wholesale Market Service Rate	185,675	0.0036	668.43	185,675	0.0036	668.43	0.00	0.00%	2.17%
Rural Rate Protection Charge	185,675	0.0003	55.70	185,675	0.0003	55.70	0.00	0.00%	0.18%
Ontario Electricity Support Program Charge	185,675	0.0000	0.00	185,675	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**724.38**			**724.38**	**0.00**	**0.00%**	**2.35%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**3.98%**
Total Electricity Charge on Two-Tier RPP (before HST)			**27,063.42**			**27,259.24**	**195.82**	**0.72%**	**88.50%**
HST		0.13	3,518.24		0.13	3,543.70	25.46	0.72%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**30,581.66**			**30,802.94**	**221.28**	**0.72%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**30,581.66**			**30,802.94**	**221.28**	**0.72%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	300
Peak (kW)	10
Loss factor	1.061
Load factor	4%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	318
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	318	0.077	24.51	318	0.077	24.51	0.00	0.00%	6.06%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**24.51**			**24.51**	**0.00**	**0.00%**	**6.06%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	48.50%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	10	11.4922	114.92	10	12.169	121.69	6.77	5.89%	30.09%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10	0.00282	0.03	10	0.00282	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**311.12**			**317.89**	**6.77**	**2.18%**	**78.60%**
Retail Transmission Rate – Network Service Rate	10	0.6395	6.40	10	0.6395	6.40	0.00	0.00%	1.58%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10	0.5543	5.54	10	0.5543	5.54	0.00	0.00%	1.37%
Sub-Total: Retail Transmission			**11.94**			**11.94**	**0.00**	**0.00%**	**2.95%**
Sub-Total: Delivery			**323.06**			**329.83**	**6.77**	**2.09%**	**81.55%**
Wholesale Market Service Rate	318	0.0036	1.15	318	0.0036	1.15	0.00	0.00%	0.28%
Rural Rate Protection Charge	318	0.0003	0.10	318	0.0003	0.10	0.00	0.00%	0.02%
Ontario Electricity Support Program Charge	318	0.0000	0.00	318	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%
Sub-Total: Regulatory			**1.49**			**1.49**	**0.00**	**0.00%**	**0.37%**
Debt Retirement Charge (DRC)	300	0.007	**2.10**	300	0.007	**2.10**	**0.00**	**0.00%**	**0.52%**
Total Electricity Charge on Two-Tier RPP (before HST)			**351.16**			**357.93**	**6.77**	**1.93%**	**88.50%**
HST		0.13	45.65		0.13	46.53	0.88	1.93%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**396.81**			**404.46**	**7.65**	**1.93%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**396.81**			**404.46**	**7.65**	**1.93%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	1,328
Peak (kW)	12
Loss factor	1.061
Load factor	15%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,409
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,409	0.077	108.49	1,409	0.077	108.49	0.00	0.00%	20.00%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**108.49**			**108.49**	**0.00**	**0.00%**	**20.00%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	36.16%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	12	11.4922	137.91	12	12.169	146.03	8.12	5.89%	26.92%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	12	0.00282	0.03	12	0.00282	0.03	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**334.11**			**342.23**	**8.12**	**2.43%**	**63.08%**
Retail Transmission Rate – Network Service Rate	12	0.6395	7.67	12	0.6395	7.67	0.00	0.00%	1.41%
Retail Transmission Rate – Line and Transformation Connection Service Rate	12	0.5543	6.65	12	0.5543	6.65	0.00	0.00%	1.23%
Sub-Total: Retail Transmission			**14.33**			**14.33**	**0.00**	**0.00%**	**2.64%**
Sub-Total: Delivery			**348.44**			**356.56**	**8.12**	**2.33%**	**65.72%**
Wholesale Market Service Rate	1,409	0.0036	5.07	1,409	0.0036	5.07	0.00	0.00%	0.94%
Rural Rate Protection Charge	1,409	0.0003	0.42	1,409	0.0003	0.42	0.00	0.00%	0.08%
Ontario Electricity Support Program Charge	1,409	0.0000	0.00	1,409	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**5.75**			**5.75**	**0.00**	**0.00%**	**1.06%**
Debt Retirement Charge (DRC)	1,328	0.007	**9.30**	1,328	0.007	**9.30**	**0.00**	**0.00%**	**1.71%**
Total Electricity Charge on Two-Tier RPP (before HST)			**471.97**			**480.09**	**8.12**	**1.72%**	**88.50%**
HST		0.13	61.36		0.13	62.41	1.06	1.72%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**533.33**			**542.51**	**9.18**	**1.72%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**533.33**			**542.51**	**9.18**	**1.72%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	DGen
Monthly Consumption (kWh)	5,000
Peak (kW)	100
Loss factor	1.061
Load factor	7%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	5,305
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	5,305	0.077	408.49	5,305	0.077	408.49	0.00	0.00%	18.10%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**408.49**			**408.49**	**0.00**	**0.00%**	**18.10%**
Service Charge	1	196.16	196.16	1	196.16	196.16	0.00	0.00%	8.69%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	11.4922	1,149.22	100	12.169	1,216.90	67.68	5.89%	53.92%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	100	0.00282	0.28	100	0.00282	0.28	0.00	0.00%	0.01%
Volumetric Global Adjustment Account Rider	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,345.67**			**1,413.35**	**67.68**	**5.03%**	**62.63%**
Retail Transmission Rate – Network Service Rate	100	0.6395	63.95	100	0.6395	63.95	0.00	0.00%	2.83%
Retail Transmission Rate – Line and Transformation Connection Service Rate	100	0.5543	55.43	100	0.5543	55.43	0.00	0.00%	2.46%
Sub-Total: Retail Transmission			**119.38**			**119.38**	**0.00**	**0.00%**	**5.29%**
Sub-Total: Delivery			**1,465.05**			**1,532.73**	**67.68**	**4.62%**	**67.92%**
Wholesale Market Service Rate	5,305	0.0036	19.10	5,305	0.0036	19.10	0.00	0.00%	0.85%
Rural Rate Protection Charge	5,305	0.0003	1.59	5,305	0.0003	1.59	0.00	0.00%	0.07%
Ontario Electricity Support Program Charge	5,305	0.0000	0.00	5,305	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**20.94**			**20.94**	**0.00**	**0.00%**	**0.93%**
Debt Retirement Charge (DRC)	5,000	0.007	**35.00**	5,000	0.007	**35.00**	**0.00**	**0.00%**	**1.55%**
Total Electricity Charge on Two-Tier RPP (before HST)			**1,929.48**			**1,997.16**	**67.68**	**3.51%**	**88.50%**
HST		0.13	250.83		0.13	259.63	8.80	3.51%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,180.31**			**2,256.79**	**76.48**	**3.51%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,180.31**			**2,256.79**	**76.48**	**3.51%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	200,000
Peak (kW)	500
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	206,800
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	206,800	0.077	15,923.60	206,800	0.077	15,923.60	0.00	0.00%	60.73%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15,923.60**			**15,923.60**	**0.00**	**0.00%**	**60.73%**
Service Charge	1	1270.37	1,270.37	1	1300.23	1,300.23	29.86	2.35%	4.96%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.01%
Distribution Volumetric Rate	500	1.4497	724.83	500	1.4912	745.59	20.76	2.86%	2.84%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	-0.1367	-68.34	500	-0.1367	-68.34	0.00	0.00%	-0.26%
Volumetric Global Adjustment Account Rider	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,930.69**			**1,981.31**	**50.62**	**2.62%**	**7.56%**
Retail Transmission Rate – Network Service Rate	500	3.5367	1,768.35	500	3.5367	1,768.35	0.00	0.00%	6.74%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	2.6514	1,325.70	500	2.6514	1,325.70	0.00	0.00%	5.06%
Sub-Total: Retail Transmission			**3,094.05**			**3,094.05**	**0.00**	**0.00%**	**11.80%**
Sub-Total: Delivery			**5,024.74**			**5,075.36**	**50.62**	**1.01%**	**19.35%**
Wholesale Market Service Rate	206,800	0.0036	744.48	206,800	0.0036	744.48	0.00	0.00%	2.84%
Rural Rate Protection Charge	206,800	0.0003	62.04	206,800	0.0003	62.04	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	206,800	0.0000	0.00	206,800	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**806.77**			**806.77**	**0.00**	**0.00%**	**3.08%**
Debt Retirement Charge (DRC)	200,000	0.007	**1,400.00**	200,000	0.007	**1,400.00**	**0.00**	**0.00%**	**5.34%**
Total Electricity Charge on Two-Tier RPP (before HST)			**23,155.11**			**23,205.73**	**50.62**	**0.22%**	**88.50%**
HST		0.13	3,010.16		0.13	3,016.74	6.58	0.22%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**26,165.27**			**26,222.47**	**57.20**	**0.22%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**26,165.27**			**26,222.47**	**57.20**	**0.22%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	1,601,036
Peak (kW)	2,960
Loss factor	1.034
Load factor	74%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	1,655,471
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	1,655,471	0.077	127,471.28	1,655,471	0.077	127,471.28	0.00	0.00%	66.84%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**127,471.28**			**127,471.28**	**0.00**	**0.00%**	**66.84%**
Service Charge	1	1270.37	1,270.37	1	1300.23	1,300.23	29.86	2.35%	0.68%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	2,960	1.4497	4,291.01	2,960	1.4912	4,413.91	122.90	2.86%	2.31%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	2,960	-0.1367	-404.54	2,960	-0.1367	-404.54	0.00	0.00%	-0.21%
Volumetric Global Adjustment Account Rider	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**5,160.65**			**5,313.41**	**152.76**	**2.96%**	**2.79%**
Retail Transmission Rate – Network Service Rate	2,960	3.5367	10,468.63	2,960	3.5367	10,468.63	0.00	0.00%	5.49%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,960	2.6514	7,848.14	2,960	2.6514	7,848.14	0.00	0.00%	4.12%
Sub-Total: Retail Transmission			**18,316.78**			**18,316.78**	**0.00**	**0.00%**	**9.60%**
Sub-Total: Delivery			**23,477.43**			**23,630.19**	**152.76**	**0.65%**	**12.39%**
Wholesale Market Service Rate	1,655,471	0.0036	5,959.70	1,655,471	0.0036	5,959.70	0.00	0.00%	3.13%
Rural Rate Protection Charge	1,655,471	0.0003	496.64	1,655,471	0.0003	496.64	0.00	0.00%	0.26%
Ontario Electricity Support Program Charge	1,655,471	0.0000	0.00	1,655,471	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**6,456.59**			**6,456.59**	**0.00**	**0.00%**	**3.39%**
Debt Retirement Charge (DRC)	1,601,036	0.007	**11,207.25**	1,601,036	0.007	**11,207.25**	**0.00**	**0.00%**	**5.88%**
Total Electricity Charge on Two-Tier RPP (before HST)			**168,612.55**			**168,765.31**	**152.76**	**0.09%**	**88.50%**
HST		0.13	21,919.63		0.13	21,939.49	19.86	0.09%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**190,532.18**			**190,704.81**	**172.62**	**0.09%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**190,532.18**			**190,704.81**	**172.62**	**0.09%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	ST
Monthly Consumption (kWh)	4,000,000
Peak (kW)	10,000
Loss factor	1.034
Load factor	55%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	4,136,000
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	4,136,000	0.077	318,472.00	4,136,000	0.077	318,472.00	0.00	0.00%	64.15%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**318,472.00**			**318,472.00**	**0.00**	**0.00%**	**64.15%**
Service Charge	1	1270.37	1,270.37	1	1300.23	1,300.23	29.86	2.35%	0.26%
Fixed Deferral/Variance Account Rider	1	3.82	3.82	1	3.82	3.82	0.00	0.00%	0.00%
Distribution Volumetric Rate	10,000	1.4497	14,496.64	10,000	1.4912	14,911.85	415.21	2.86%	3.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	10,000	-0.1367	-1,366.70	10,000	-0.1367	-1,366.70	0.00	0.00%	-0.28%
Volumetric Global Adjustment Account Rider	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**14,404.13**			**14,849.20**	**445.07**	**3.09%**	**2.99%**
Retail Transmission Rate – Network Service Rate	10,000	3.5367	35,367.00	10,000	3.5367	35,367.00	0.00	0.00%	7.12%
Retail Transmission Rate – Line and Transformation Connection Service Rate	10,000	2.6514	26,514.00	10,000	2.6514	26,514.00	0.00	0.00%	5.34%
Sub-Total: Retail Transmission			**61,881.00**			**61,881.00**	**0.00**	**0.00%**	**12.46%**
Sub-Total: Delivery			**76,285.13**			**76,730.20**	**445.07**	**0.58%**	**15.46%**
Wholesale Market Service Rate	4,136,000	0.0036	14,889.60	4,136,000	0.0036	14,889.60	0.00	0.00%	3.00%
Rural Rate Protection Charge	4,136,000	0.0003	1,240.80	4,136,000	0.0003	1,240.80	0.00	0.00%	0.25%
Ontario Electricity Support Program Charge	4,136,000	0.0000	0.00	4,136,000	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**16,130.65**			**16,130.65**	**0.00**	**0.00%**	**3.25%**
Debt Retirement Charge (DRC)	4,000,000	0.007	**28,000.00**	4,000,000	0.007	**28,000.00**	**0.00**	**0.00%**	**5.64%**
Total Electricity Charge on Two-Tier RPP (before HST)			**438,887.78**			**439,332.85**	**445.07**	**0.10%**	**88.50%**
HST		0.13	57,055.41		0.13	57,113.27	57.86	0.10%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**495,943.20**			**496,446.12**	**502.93**	**0.10%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**495,943.20**			**496,446.12**	**502.93**	**0.10%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	14.07%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**14.07%**
Service Charge	1	37.37	37.37	1	38.3	38.30	0.93	2.49%	70.00%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	100	0.0303	3.03	100	0.0309	3.09	0.06	1.98%	5.65%
Volumetric Deferral/Variance Account Rider (including CBR Class I	100	0.00002	0.00	100	0.00002	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.40**			**41.39**	**0.99**	**2.45%**	**75.66%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	1.29%
Sub-Total: Distribution			**41.11**			**42.10**	**0.99**	**2.41%**	**76.95%**
Retail Transmission Rate – Network Service Rate	109	0.0047	0.51	109	0.0047	0.51	0.00	0.00%	0.94%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0038	0.41	109	0.0038	0.41	0.00	0.00%	0.76%
Sub-Total: Retail Transmission			**0.93**			**0.93**	**0.00**	**0.00%**	**1.70%**
Sub-Total: Delivery			**42.04**			**43.03**	**0.99**	**2.35%**	**78.65%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	0.72%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.06%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.46%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**1.24%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**1.28%**
Total Electricity Charge on Two-Tier RPP (before HST)			**51.12**			**52.11**	**0.99**	**1.94%**	**95.24%**
HST		0.13	6.65		0.13	6.77	0.13	1.94%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**57.76**			**58.88**	**1.12**	**1.94%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.09		-0.08	-4.17	-0.08	-1.94%	-7.62%
Total Amount on Two-Tier RPP			**53.67**			**54.71**	**1.04**	**1.94%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	364
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	397
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	364	0.077	28.03	364	0.077	28.03	0.00	0.00%	30.37%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**28.03**			**28.03**	**0.00**	**0.00%**	**30.37%**
Service Charge	1	37.37	37.37	1	38.3	38.30	0.93	2.49%	41.50%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	364	0.0303	11.03	364	0.0309	11.25	0.22	1.98%	12.19%
Volumetric Deferral/Variance Account Rider (including CBR Class I	364	0.00002	0.01	364	0.00002	0.01	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**48.41**			**49.56**	**1.15**	**2.37%**	**53.70%**
Line Losses on Cost of Power	33	0.0770	2.58	33	0.0770	2.58	0.00	0.00%	2.79%
Sub-Total: Distribution			**50.99**			**52.14**	**1.15**	**2.25%**	**56.49%**
Retail Transmission Rate – Network Service Rate	397	0.0047	1.87	397	0.0047	1.87	0.00	0.00%	2.02%
Retail Transmission Rate – Line and Transformation Connection S	397	0.0038	1.51	397	0.0038	1.51	0.00	0.00%	1.64%
Sub-Total: Retail Transmission			**3.38**			**3.38**	**0.00**	**0.00%**	**3.66%**
Sub-Total: Delivery			**54.37**			**55.51**	**1.15**	**2.11%**	**60.16%**
Wholesale Market Service Rate	397	0.0036	1.43	397	0.0036	1.43	0.00	0.00%	1.55%
Rural Rate Protection Charge	397	0.0003	0.12	397	0.0003	0.12	0.00	0.00%	0.13%
Ontario Electricity Support Program Charge	397	0.0000	0.00	397	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.27%
Sub-Total: Regulatory			**1.80**			**1.80**	**0.00**	**0.00%**	**1.95%**
Debt Retirement Charge (DRC)	364	0.007	**2.55**	364	0.007	**2.55**	**0.00**	**0.00%**	**2.76%**
Total Electricity Charge on Two-Tier RPP (before HST)			**86.74**			**87.89**	**1.15**	**1.32%**	**95.24%**
HST		0.13	11.28		0.13	11.43	0.15	1.32%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**98.02**			**99.32**	**1.30**	**1.32%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.94		-0.08	-7.03	-0.09	-1.32%	-7.62%
Total Amount on Two-Tier RPP			**91.08**			**92.28**	**1.21**	**1.32%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	USL
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1092
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	30.80%
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.00%
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**42.81%**
Service Charge	1	37.37	37.37	1	38.3	38.30	0.93	2.49%	20.43%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0303	30.30	1,000	0.0309	30.90	0.60	1.98%	16.48%
Volumetric Deferral/Variance Account Rider (including CBR Class I	1,000	0.00002	0.02	1,000	0.00002	0.02	0.00	0.00%	0.01%
Sub-Total: Distribution (excluding pass through)			**67.69**			**69.22**	**1.53**	**2.26%**	**36.92%**
Line Losses on Cost of Power	92	0.0900	8.28	92	0.0900	8.28	0.00	0.00%	4.42%
Sub-Total: Distribution			**75.97**			**77.50**	**1.53**	**2.01%**	**41.34%**
Retail Transmission Rate – Network Service Rate	1,092	0.0047	5.13	1,092	0.0047	5.13	0.00	0.00%	2.74%
Retail Transmission Rate – Line and Transformation Connection S	1,092	0.0038	4.15	1,092	0.0038	4.15	0.00	0.00%	2.21%
Sub-Total: Retail Transmission			**9.28**			**9.28**	**0.00**	**0.00%**	**4.95%**
Sub-Total: Delivery			**85.25**			**86.78**	**1.53**	**1.79%**	**46.29%**
Wholesale Market Service Rate	1,092	0.0036	3.93	1,092	0.0036	3.93	0.00	0.00%	2.10%
Rural Rate Protection Charge	1,092	0.0003	0.33	1,092	0.0003	0.33	0.00	0.00%	0.17%
Ontario Electricity Support Program Charge	1,092	0.0000	0.00	1,092	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%
Sub-Total: Regulatory			**4.51**			**4.51**	**0.00**	**0.00%**	**2.41%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.73%**
Total Electricity Charge on Two-Tier RPP (before HST)			**177.01**			**178.54**	**1.53**	**0.86%**	**95.24%**
HST		0.13	23.01		0.13	23.21	0.20	0.86%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**200.02**			**201.75**	**1.73**	**0.86%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.16		-0.08	-14.28	-0.12	-0.86%	-7.62%
Total Amount on Two-Tier RPP			**185.86**			**187.47**	**1.61**	**0.86%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	20
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	21.84
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	20	0.077	1.54	20	0.077	1.54	0.00	0.00%	16.16%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1.54**			**1.54**	**0.00**	**0.00%**	**16.16%**
Service Charge	1	3.72	3.72	1	3.87	3.87	0.15	4.03%	40.62%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.06%
Distribution Volumetric Rate	20	0.1383	2.77	20	0.1440	2.88	0.11	4.12%	30.23%
Volumetric Deferral/Variance Account Rider (including CBR Class	20	-0.00006	0.00	20	-0.00006	0.00	0.00	0.00%	-0.01%
Sub-Total: Distribution (excluding pass through)			**6.49**			**6.75**	**0.26**	**4.07%**	**70.89%**
Line Losses on Cost of Power	2	0.0770	0.14	2	0.0770	0.14	0.00	0.00%	1.49%
Sub-Total: Distribution			**6.63**			**6.90**	**0.26**	**3.98%**	**72.38%**
Retail Transmission Rate – Network Service Rate	22	0.0038	0.08	22	0.003836	0.08	0.00	0.00%	0.88%
Retail Transmission Rate – Line and Transformation Connection S	22	0.0036	0.08	22	0.003624	0.08	0.00	0.00%	0.83%
Sub-Total: Retail Transmission			**0.16**			**0.16**	**0.00**	**0.00%**	**1.71%**
Sub-Total: Delivery			**6.80**			**7.06**	**0.26**	**3.88%**	**74.09%**
Wholesale Market Service Rate	22	0.0036	0.08	22	0.0036	0.08	0.00	0.00%	0.83%
Rural Rate Protection Charge	22	0.0003	0.01	22	0.0003	0.01	0.00	0.00%	0.07%
Ontario Electricity Support Program Charge	22	0.0000	0.00	22	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	2.62%
Sub-Total: Regulatory			**0.34**			**0.34**	**0.00**	**0.00%**	**3.52%**
Debt Retirement Charge (DRC)	20	0.007	**0.14**	20	0.007	**0.14**	**0.00**	**0.00%**	**1.47%**
Total Electricity Charge on Two-Tier RPP (before HST)			**8.81**			**9.07**	**0.26**	**3.00%**	**95.24%**
HST		0.13	1.15		0.13	1.18	0.03	3.00%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**9.96**			**10.25**	**0.30**	**3.00%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-0.70		-0.08	-0.73	-0.02	-3.00%	-7.62%
Total Amount on Two-Tier RPP			**9.25**			**9.53**	**0.28**	**3.00%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	71
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	77.532
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	71	0.077	5.47	71	0.077	5.47	0.00	0.00%	24.00%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**5.47**			**5.47**	**0.00**	**0.00%**	**24.00%**
Service Charge	1	3.72	3.72	1	3.87	3.87	0.15	4.03%	16.99%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	71	0.1383	9.82	71	0.1440	10.22	0.40	4.12%	44.89%
Volumetric Deferral/Variance Account Rider (including CBR Class	71	-0.00006	0.00	71	-0.00006	0.00	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**13.54**			**14.10**	**0.55**	**4.10%**	**61.88%**
Line Losses on Cost of Power	7	0.0770	0.50	7	0.0770	0.50	0.00	0.00%	2.21%
Sub-Total: Distribution			**14.04**			**14.60**	**0.55**	**3.95%**	**64.09%**
Retail Transmission Rate – Network Service Rate	78	0.0038	0.30	78	0.003836	0.30	0.00	0.00%	1.31%
Retail Transmission Rate – Line and Transformation Connection S	78	0.0036	0.28	78	0.003624	0.28	0.00	0.00%	1.23%
Sub-Total: Retail Transmission			**0.58**			**0.58**	**0.00**	**0.00%**	**2.54%**
Sub-Total: Delivery			**14.62**			**15.18**	**0.55**	**3.79%**	**66.63%**
Wholesale Market Service Rate	78	0.0036	0.28	78	0.0036	0.28	0.00	0.00%	1.23%
Rural Rate Protection Charge	78	0.0003	0.02	78	0.0003	0.02	0.00	0.00%	0.10%
Ontario Electricity Support Program Charge	78	0.0000	0.00	78	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.10%
Sub-Total: Regulatory			**0.55**			**0.55**	**0.00**	**0.00%**	**2.43%**
Debt Retirement Charge (DRC)	71	0.007	**0.50**	71	0.007	**0.50**	**0.00**	**0.00%**	**2.18%**
Total Electricity Charge on Two-Tier RPP (before HST)			**21.14**			**21.69**	**0.55**	**2.62%**	**95.24%**
HST		0.13	2.75		0.13	2.82	0.07	2.62%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**23.89**			**24.51**	**0.63**	**2.62%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-1.69		-0.08	-1.74	-0.04	-2.62%	-7.62%
Total Amount on Two-Tier RPP			**22.20**			**22.78**	**0.58**	**2.62%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	Sen Lgt
Monthly Consumption (kWh)	200
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	218.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	200	0.077	15.40	200	0.077	15.40	0.00	0.00%	27.36%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**15.40**			**15.40**	**0.00**	**0.00%**	**27.36%**
Service Charge	1	3.72	3.72	1	3.87	3.87	0.15	4.03%	6.87%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	200	0.1383	27.66	200	0.1440	28.80	1.14	4.12%	51.16%
Volumetric Deferral/Variance Account Rider (including CBR Class I	200	-0.00006	-0.01	200	-0.00006	-0.01	0.00	0.00%	-0.02%
Sub-Total: Distribution (excluding pass through)			**31.37**			**32.66**	**1.29**	**4.11%**	**58.03%**
Line Losses on Cost of Power	18	0.0770	1.42	18	0.0770	1.42	0.00	0.00%	2.52%
Sub-Total: Distribution			**32.79**			**34.08**	**1.29**	**3.93%**	**60.54%**
Retail Transmission Rate – Network Service Rate	218	0.0038	0.84	218	0.003836	0.84	0.00	0.00%	1.49%
Retail Transmission Rate – Line and Transformation Connection S	218	0.0036	0.79	218	0.003624	0.79	0.00	0.00%	1.41%
Sub-Total: Retail Transmission			**1.63**			**1.63**	**0.00**	**0.00%**	**2.89%**
Sub-Total: Delivery			**34.42**			**35.71**	**1.29**	**3.75%**	**63.44%**
Wholesale Market Service Rate	218	0.0036	0.79	218	0.0036	0.79	0.00	0.00%	1.40%
Rural Rate Protection Charge	218	0.0003	0.07	218	0.0003	0.07	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	218	0.0000	0.00	218	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.44%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	**0.00%**	**1.96%**
Debt Retirement Charge (DRC)	200	0.007	**1.40**	200	0.007	**1.40**	**0.00**	**0.00%**	**2.49%**
Total Electricity Charge on Two-Tier RPP (before HST)			**52.32**			**53.61**	**1.29**	**2.47%**	**95.24%**
HST		0.13	6.80		0.13	6.97	0.17	2.47%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**59.12**			**60.58**	**1.46**	**2.47%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-4.19		-0.08	-4.29	-0.10	-2.47%	-7.62%
Total Amount on Two-Tier RPP			**54.94**			**56.29**	**1.35**	**2.47%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	100
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	109.2
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	100	0.077	7.70	100	0.077	7.70	0.00	0.00%	27.72%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**7.70**			**7.70**	**0.00**	**0.00%**	**27.72%**
Service Charge	1	4.77	4.77	1	4.88	4.88	0.11	2.31%	17.57%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.03%
Distribution Volumetric Rate	100	0.1069	10.69	100	0.1097	10.97	0.28	2.62%	39.49%
Volumetric Deferral/Variance Account Rider (including CBR Class I	100	-0.00001	0.00	100	-0.00001	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**15.47**			**15.86**	**0.39**	**2.52%**	**57.08%**
Line Losses on Cost of Power	9	0.0770	0.71	9	0.0770	0.71	0.00	0.00%	2.55%
Sub-Total: Distribution			**16.17**			**16.56**	**0.39**	**2.41%**	**59.63%**
Retail Transmission Rate – Network Service Rate	109	0.0038	0.42	109	0.003836	0.42	0.00	0.00%	1.51%
Retail Transmission Rate – Line and Transformation Connection S	109	0.0036	0.40	109	0.003624	0.40	0.00	0.00%	1.42%
Sub-Total: Retail Transmission			**0.81**			**0.81**	**0.00**	**0.00%**	**2.93%**
Sub-Total: Delivery			**16.99**			**17.38**	**0.39**	**2.30%**	**62.56%**
Wholesale Market Service Rate	109	0.0036	0.39	109	0.0036	0.39	0.00	0.00%	1.42%
Rural Rate Protection Charge	109	0.0003	0.03	109	0.0003	0.03	0.00	0.00%	0.12%
Ontario Electricity Support Program Charge	109	0.0000	0.00	109	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.90%
Sub-Total: Regulatory			**0.68**			**0.68**	**0.00**	**0.00%**	**2.43%**
Debt Retirement Charge (DRC)	100	0.007	**0.70**	100	0.007	**0.70**	**0.00**	**0.00%**	**2.52%**
Total Electricity Charge on Two-Tier RPP (before HST)			**26.06**			**26.45**	**0.39**	**1.50%**	**95.24%**
HST		0.13	3.39		0.13	3.44	0.05	1.50%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**29.45**			**29.89**	**0.44**	**1.50%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-2.09		-0.08	-2.12	-0.03	-1.50%	-7.62%
Total Amount on Two-Tier RPP			**27.37**			**27.78**	**0.41**	**1.50%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	517
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	564.564
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	517	0.077	39.81	517	0.077	39.81	0.00	0.00%	32.87%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**39.81**			**39.81**	**0.00**	**0.00%**	**32.87%**
Service Charge	1	4.77	4.77	1	4.88	4.88	0.11	2.31%	4.03%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.01%
Distribution Volumetric Rate	517	0.1069	55.27	517	0.1097	56.71	1.45	2.62%	46.83%
Volumetric Deferral/Variance Account Rider (including CBR Class I	517	-0.00001	-0.01	517	-0.00001	-0.01	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**60.04**			**61.60**	**1.56**	**2.59%**	**50.86%**
Line Losses on Cost of Power	48	0.0770	3.66	48	0.0770	3.66	0.00	0.00%	3.02%
Sub-Total: Distribution			**63.70**			**65.26**	**1.56**	**2.45%**	**53.88%**
Retail Transmission Rate – Network Service Rate	565	0.0038	2.17	565	0.003836	2.17	0.00	0.00%	1.79%
Retail Transmission Rate – Line and Transformation Connection Se	565	0.0036	2.05	565	0.003624	2.05	0.00	0.00%	1.69%
Sub-Total: Retail Transmission			**4.21**			**4.21**	**0.00**	**0.00%**	**3.48%**
Sub-Total: Delivery			**67.91**			**69.47**	**1.56**	**2.29%**	**57.36%**
Wholesale Market Service Rate	565	0.0036	2.03	565	0.0036	2.03	0.00	0.00%	1.68%
Rural Rate Protection Charge	565	0.0003	0.17	565	0.0003	0.17	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	565	0.0000	0.00	565	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%
Sub-Total: Regulatory			**2.45**			**2.45**	**0.00**	**0.00%**	**2.02%**
Debt Retirement Charge (DRC)	517	0.007	**3.62**	517	0.007	**3.62**	**0.00**	**0.00%**	**2.99%**
Total Electricity Charge on Two-Tier RPP (before HST)			**113.79**			**115.35**	**1.56**	**1.37%**	**95.24%**
HST		0.13	14.79		0.13	15.00	0.20	1.37%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**128.59**			**130.35**	**1.76**	**1.37%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.10		-0.08	-9.23	-0.12	-1.37%	-7.62%
Total Amount on Two-Tier RPP			**119.48**			**121.12**	**1.64**	**1.37%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	St Lgt
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.092
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2184
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	12.22%
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	23.80%
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**36.02%**
Service Charge	1	4.77	4.77	1	4.88	4.88	0.11	2.31%	1.03%
Fixed Deferral/Variance Account Rider	1	0.01	0.01	1	0.01	0.01	0.00	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.1069	213.80	2,000	0.1097	219.40	5.60	2.62%	46.42%
Volumetric Deferral/Variance Account Rider (including CBR Class I	2,000	-0.00001	-0.02	2,000	-0.00001	-0.02	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**218.56**			**224.27**	**5.71**	**2.61%**	**47.45%**
Line Losses on Cost of Power	184	0.0900	16.56	184	0.0900	16.56	0.00	0.00%	3.50%
Sub-Total: Distribution			**235.12**			**240.83**	**5.71**	**2.43%**	**50.95%**
Retail Transmission Rate – Network Service Rate	2,184	0.0038	8.38	2,184	0.003836	8.38	0.00	0.00%	1.77%
Retail Transmission Rate – Line and Transformation Connection S	2,184	0.0036	7.91	2,184	0.003624	7.91	0.00	0.00%	1.67%
Sub-Total: Retail Transmission			**16.29**			**16.29**	**0.00**	**0.00%**	**3.45%**
Sub-Total: Delivery			**251.41**			**257.12**	**5.71**	**2.27%**	**54.40%**
Wholesale Market Service Rate	2,184	0.0036	7.86	2,184	0.0036	7.86	0.00	0.00%	1.66%
Rural Rate Protection Charge	2,184	0.0003	0.66	2,184	0.0003	0.66	0.00	0.00%	0.14%
Ontario Electricity Support Program Charge	2,184	0.0000	0.00	2,184	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.05%
Sub-Total: Regulatory			**8.77**			**8.77**	**0.00**	**0.00%**	**1.86%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**2.96%**
Total Electricity Charge on Two-Tier RPP (before HST)			**444.43**			**450.14**	**5.71**	**1.28%**	**95.24%**
HST		0.13	57.78		0.13	58.52	0.74	1.28%	12.38%
Total Electricity Charge on Two-Tier RPP (including HST)			**502.20**			**508.66**	**6.45**	**1.28%**	**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-35.55		-0.08	-36.01	-0.46	-1.28%	-7.62%
Total Amount on Two-Tier RPP			**466.65**			**472.64**	**6.00**	**1.28%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AUR
Monthly Consumption (kWh)	350
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	370
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	350	0.077	26.95	350	0.077	26.95	0.00	0.00%	37.99%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**26.95**			**26.95**	**0.00**	**0.00%**	**37.99%**	
TOU-Off Peak	228	0.065	14.79	228	0.065	14.79	0.00	0.00%		20.27%
TOU-Mid Peak	60	0.095	5.65	60	0.095	5.65	0.00	0.00%		7.75%
TOU-On Peak	63	0.132	8.32	63	0.132	8.32	0.00	0.00%		11.40%
Sub-Total: Energy (TOU)			**28.76**			**28.76**	0.00	0.00%	**40.54%**	**39.43%**
Service Charge	1	30.78	30.78	1	31.59	31.59	0.81	2.63%	44.54%	43.31%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	350	0.0000	0.00	350	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	350	0.0000	0.00	350	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**30.78**			**31.59**	**0.81**	**2.63%**	**44.54%**	**43.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	1.11%	1.08%
Line Losses on Cost of Power (based on two-tier RPP prices)	20	0.0770	1.54	20	0.0770	1.54	0.00	0.00%	2.17%	2.11%
Line Losses on Cost of Power (based on TOU prices)	20	0.0822	1.64	20	0.0822	1.64	0.00	0.00%	2.31%	2.25%
Sub-Total: Distribution (based on two-tier RPP prices)			**33.11**			**33.92**	**0.81**	**2.45%**	**47.82%**	**46.50%**
Sub-Total: Distribution (based on TOU prices)			**33.21**			**34.02**	**0.81**	**2.44%**	**47.96%**	**46.64%**
Retail Transmission Rate – Network Service Rate	370	0.0073	2.70	370	0.0073	2.70	0.00	0.00%	3.81%	3.70%
Retail Transmission Rate – Line and Transformation Connection S	370	0.0062	2.29	370	0.0062	2.29	0.00	0.00%	3.23%	3.14%
Sub-Total: Retail Transmission			**4.99**			**4.99**	**0.00**	**0.00%**	**7.04%**	**6.85%**
Sub-Total: Delivery (based on two-tier RPP prices)			**38.10**			**38.91**	**0.81**	**2.13%**	**54.86%**	**53.35%**
Sub-Total: Delivery (based on TOU prices)			**38.20**			**39.01**	**0.81**	**2.12%**	**55.00%**	**53.49%**
Wholesale Market Service Rate	370	0.0036	1.33	370	0.0036	1.33	0.00	0.00%	1.88%	1.83%
Rural Rate Protection Charge	370	0.0003	0.11	370	0.0003	0.11	0.00	0.00%	0.16%	0.15%
Ontario Electricity Support Program Charge	370	0.0000	0.00	370	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.35%	0.34%
Sub-Total: Regulatory			**1.69**			**1.69**	**0.00**	**0.00%**	**2.39%**	**2.32%**
Debt Retirement Charge (DRC)	350	0.000	**0.00**	350	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**66.74**			**67.55**	**0.81**	**1.21%**	**95.24%**	
HST		0.13	8.68		0.13	8.78	0.11	1.21%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**75.42**			**76.34**	**0.92**	**1.21%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.34		-0.08	-5.40	-0.06	-1.21%	-7.62%	
Total Amount on Two-Tier RPP			**70.08**			**70.93**	**0.85**	**1.21%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**68.65**			**69.46**	**0.81**	**1.18%**		**95.24%**
HST		0.13	8.92		0.13	9.03	0.11	1.18%		12.38%
Total Electricity Charge on TOU (including HST)			**77.58**			**78.49**	**0.92**	**1.18%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-5.49		-0.08	-5.56	-0.06	-1.18%		-7.62%
Total Amount on TOU			**72.08**			**72.94**	**0.85**	**1.18%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	AUR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	793
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	40.01%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	11.69%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**51.70%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		27.05%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		10.34%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		15.21%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**53.36%**	**52.61%**
Service Charge	1	30.78	30.78	1	31.59	31.59	0.81	2.63%	27.36%	26.97%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	750	0.0000	0.00	750	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**30.78**			**31.59**	**0.81**	**2.63%**	**27.36%**	**26.97%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.68%	0.67%
Line Losses on Cost of Power (based on two-tier RPP prices)	43	0.0900	3.85	43	0.0900	3.85	0.00	0.00%	3.33%	3.28%
Line Losses on Cost of Power (based on TOU prices)	43	0.0822	3.51	43	0.0822	3.51	0.00	0.00%	3.04%	3.00%
Sub-Total: Distribution (based on two-tier RPP prices)			**35.42**			**36.23**	**0.81**	**2.29%**	**31.37%**	**30.93%**
Sub-Total: Distribution (based on TOU prices)			**35.08**			**35.89**	**0.81**	**2.31%**	**31.08%**	**30.64%**
Retail Transmission Rate – Network Service Rate	793	0.0073	5.79	793	0.0073	5.79	0.00	0.00%	5.01%	4.94%
Retail Transmission Rate – Line and Transformation Connection S	793	0.0062	4.92	793	0.0062	4.92	0.00	0.00%	4.26%	4.20%
Sub-Total: Retail Transmission			**10.70**			**10.70**	**0.00**	**0.00%**	**9.27%**	**9.14%**
Sub-Total: Delivery (based on two-tier RPP prices)			**46.12**			**46.93**	**0.81**	**1.76%**	**40.64%**	**40.06%**
Sub-Total: Delivery (based on TOU prices)			**45.78**			**46.59**	**0.81**	**1.77%**	**40.35%**	**39.78%**
Wholesale Market Service Rate	793	0.0036	2.85	793	0.0036	2.85	0.00	0.00%	2.47%	2.44%
Rural Rate Protection Charge	793	0.0003	0.24	793	0.0003	0.24	0.00	0.00%	0.21%	0.20%
Ontario Electricity Support Program Charge	793	0.0000	0.00	793	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.22%	0.21%
Sub-Total: Regulatory			**3.34**			**3.34**	**0.00**	**0.00%**	**2.89%**	**2.85%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**109.16**			**109.97**	**0.81**	**0.74%**	**95.24%**	
HST		0.13	14.19		0.13	14.30	0.11	0.74%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**123.35**			**124.27**	**0.92**	**0.74%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.73		-0.08	-8.80	-0.06	-0.74%	-7.62%	
Total Amount on Two-Tier RPP			**114.62**			**115.47**	**0.85**	**0.74%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**110.75**			**111.56**	**0.81**	**0.73%**		**95.24%**
HST		0.13	14.40		0.13	14.50	0.11	0.73%		12.38%
Total Electricity Charge on TOU (including HST)			**125.14**			**126.06**	**0.92**	**0.73%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.86		-0.08	-8.92	-0.06	-0.73%		-7.62%
Total Amount on TOU			**116.28**			**117.13**	**0.85**	**0.73%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AUR
Monthly Consumption (kWh)	505
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	534
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	505	0.077	38.89	505	0.077	38.89	0.00	0.00%	44.61%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**38.89**			**38.89**	**0.00**	**0.00%**	**44.61%**	
TOU-Off Peak	328	0.065	21.34	328	0.065	21.34	0.00	0.00%		23.69%
TOU-Mid Peak	86	0.095	8.16	86	0.095	8.16	0.00	0.00%		9.06%
TOU-On Peak	91	0.132	12.00	91	0.132	12.00	0.00	0.00%		13.32%
Sub-Total: Energy (TOU)			**41.49**			**41.49**	0.00	0.00%	**47.60%**	**46.07%**
Service Charge	1	30.78	30.78	1	31.59	31.59	0.81	2.63%	36.24%	35.08%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	505	0.0000	0.00	505	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	505	0.0000	0.00	505	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**30.78**			**31.59**	**0.81**	**2.63%**	**36.24%**	**35.08%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.91%	0.88%
Line Losses on Cost of Power (based on two-tier RPP prices)	29	0.0770	2.22	29	0.0770	2.22	0.00	0.00%	2.54%	2.46%
Line Losses on Cost of Power (based on TOU prices)	29	0.0822	2.36	29	0.0822	2.36	0.00	0.00%	2.71%	2.63%
Sub-Total: Distribution (based on two-tier RPP prices)			**33.79**			**34.60**	**0.81**	**2.40%**	**39.69%**	**38.41%**
Sub-Total: Distribution (based on TOU prices)			**33.93**			**34.74**	**0.81**	**2.39%**	**39.86%**	**38.58%**
Retail Transmission Rate – Network Service Rate	534	0.0073	3.90	534	0.0073	3.90	0.00	0.00%	4.47%	4.33%
Retail Transmission Rate – Line and Transformation Connection S	534	0.0062	3.31	534	0.0062	3.31	0.00	0.00%	3.80%	3.67%
Sub-Total: Retail Transmission			**7.21**			**7.21**	**0.00**	**0.00%**	**8.27%**	**8.00%**
Sub-Total: Delivery (based on two-tier RPP prices)			**40.99**			**41.80**	**0.81**	**1.98%**	**47.96%**	**46.42%**
Sub-Total: Delivery (based on TOU prices)			**41.14**			**41.95**	**0.81**	**1.97%**	**48.13%**	**46.58%**
Wholesale Market Service Rate	534	0.0036	1.92	534	0.0036	1.92	0.00	0.00%	2.20%	2.13%
Rural Rate Protection Charge	534	0.0003	0.16	534	0.0003	0.16	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	534	0.0000	0.00	534	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%	0.28%
Sub-Total: Regulatory			**2.33**			**2.33**	**0.00**	**0.00%**	**2.67%**	**2.59%**
Debt Retirement Charge (DRC)	505	0.000	**0.00**	505	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**82.21**			**83.02**	**0.81**	**0.99%**	**95.24%**	
HST		0.13	10.69		0.13	10.79	0.11	0.99%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**92.90**			**93.81**	**0.92**	**0.99%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.58		-0.08	-6.64	-0.06	-0.99%	-7.62%	
Total Amount on Two-Tier RPP			**86.32**			**87.17**	**0.85**	**0.99%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**84.96**			**85.77**	**0.81**	**0.95%**		**95.24%**
HST		0.13	11.05		0.13	11.15	0.11	0.95%		12.38%
Total Electricity Charge on TOU (including HST)			**96.01**			**96.92**	**0.92**	**0.95%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.80		-0.08	-6.86	-0.06	-0.95%		-7.62%
Total Amount on TOU			**89.21**			**90.06**	**0.85**	**0.95%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AUR
Monthly Consumption (kWh)	1400
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1480
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	23.94%	
Energy Second Tier (kWh)	800	0.090	72.00	800	0.090	72.00	0.00	0.00%	37.32%	
Sub-Total: Energy (RPP)			**118.20**			**118.20**	**0.00**	**0.00%**	**61.26%**	
TOU-Off Peak	910	0.065	59.15	910	0.065	59.15	0.00	0.00%		31.30%
TOU-Mid Peak	238	0.095	22.61	238	0.095	22.61	0.00	0.00%		11.97%
TOU-On Peak	252	0.132	33.26	252	0.132	33.26	0.00	0.00%		17.60%
Sub-Total: Energy (TOU)			**115.02**			**115.02**	0.00	0.00%	**59.61%**	**60.87%**
Service Charge	1	30.78	30.78	1	31.59	31.59	0.81	2.63%	16.37%	16.72%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	1,400	0.0000	0.00	1,400	0	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**30.78**			**31.59**	**0.81**	**2.63%**	**16.37%**	**16.72%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.41%	0.42%
Line Losses on Cost of Power (based on two-tier RPP prices)	80	0.0900	7.18	80	0.0900	7.18	0.00	0.00%	3.72%	3.80%
Line Losses on Cost of Power (based on TOU prices)	80	0.0822	6.56	80	0.0822	6.56	0.00	0.00%	3.40%	3.47%
Sub-Total: Distribution (based on two-tier RPP prices)			**38.75**			**39.56**	**0.81**	**2.09%**	**20.50%**	**20.94%**
Sub-Total: Distribution (based on TOU prices)			**38.13**			**38.94**	**0.81**	**2.12%**	**20.18%**	**20.61%**
Retail Transmission Rate – Network Service Rate	1,480	0.0073	10.80	1,480	0.0073	10.80	0.00	0.00%	5.60%	5.72%
Retail Transmission Rate – Line and Transformation Connection S	1,480	0.0062	9.17	1,480	0.0062	9.17	0.00	0.00%	4.76%	4.86%
Sub-Total: Retail Transmission			**19.98**			**19.98**	**0.00**	**0.00%**	**10.35%**	**10.57%**
Sub-Total: Delivery (based on two-tier RPP prices)			**58.73**			**59.54**	**0.81**	**1.38%**	**30.86%**	**31.51%**
Sub-Total: Delivery (based on TOU prices)			**58.10**			**58.91**	**0.81**	**1.39%**	**30.53%**	**31.18%**
Wholesale Market Service Rate	1,480	0.0036	5.33	1,480	0.0036	5.33	0.00	0.00%	2.76%	2.82%
Rural Rate Protection Charge	1,480	0.0003	0.44	1,480	0.0003	0.44	0.00	0.00%	0.23%	0.23%
Ontario Electricity Support Program Charge	1,480	0.0000	0.00	1,480	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.13%	0.13%
Sub-Total: Regulatory			**6.02**			**6.02**	**0.00**	**0.00%**	**3.12%**	**3.19%**
Debt Retirement Charge (DRC)	1,400	0.000	**0.00**	1,400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**182.95**			**183.76**	**0.81**	**0.44%**	**95.24%**	
HST		0.13	23.78		0.13	23.89	0.11	0.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**206.73**			**207.65**	**0.92**	**0.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.64		-0.08	-14.70	-0.06	-0.44%	-7.62%	
Total Amount on Two-Tier RPP			**192.10**			**192.95**	**0.85**	**0.44%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**179.15**			**179.96**	**0.81**	**0.45%**		**95.24%**
HST		0.13	23.29		0.13	23.39	0.11	0.45%		12.38%
Total Electricity Charge on TOU (including HST)			**202.44**			**203.35**	**0.92**	**0.45%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-14.33		-0.08	-14.40	-0.06	-0.45%		-7.62%
Total Amount on TOU			**188.11**			**188.96**	**0.85**	**0.45%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AR
Monthly Consumption (kWh)	400
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	427
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	400	0.077	30.80	400	0.077	30.80	0.00	0.00%	35.50%	
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%	
Sub-Total: Energy (RPP)			**30.80**			**30.80**	**0.00**	**0.00%**	**35.50%**	
TOU-Off Peak	260	0.065	16.90	260	0.065	16.90	0.00	0.00%		18.97%
TOU-Mid Peak	68	0.095	6.46	68	0.095	6.46	0.00	0.00%		7.25%
TOU-On Peak	72	0.132	9.50	72	0.132	9.50	0.00	0.00%		10.67%
Sub-Total: Energy (TOU)			**32.86**			**32.86**	0.00	0.00%	**37.87%**	**36.89%**
Service Charge	1	40.43	40.43	1	41.49	41.49	1.06	2.62%	47.82%	46.58%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	400	0.0000	0.00	400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	400	0.0000	0.00	400	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.43**			**41.49**	**1.06**	**2.62%**	**47.82%**	**46.58%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.91%	0.89%
Line Losses on Cost of Power (based on two-tier RPP prices)	27	0.0770	2.05	27	0.0770	2.05	0.00	0.00%	2.37%	2.31%
Line Losses on Cost of Power (based on TOU prices)	27	0.0822	2.19	27	0.0822	2.19	0.00	0.00%	2.53%	2.46%
Sub-Total: Distribution (based on two-tier RPP prices)			**43.27**			**44.33**	**1.06**	**2.45%**	**51.09%**	**49.77%**
Sub-Total: Distribution (based on TOU prices)			**43.41**			**44.47**	**1.06**	**2.44%**	**51.25%**	**49.92%**
Retail Transmission Rate – Network Service Rate	427	0.0071	3.03	427	0.0071	3.03	0.00	0.00%	3.49%	3.40%
Retail Transmission Rate – Line and Transformation Connection S	427	0.0060	2.56	427	0.006	2.56	0.00	0.00%	2.95%	2.87%
Sub-Total: Retail Transmission			**5.59**			**5.59**	**0.00**	**0.00%**	**6.44%**	**6.27%**
Sub-Total: Delivery (based on two-tier RPP prices)			**48.86**			**49.92**	**1.06**	**2.17%**	**57.54%**	**56.04%**
Sub-Total: Delivery (based on TOU prices)			**49.00**			**50.06**	**1.06**	**2.16%**	**57.69%**	**56.20%**
Wholesale Market Service Rate	427	0.0036	1.54	427	0.0036	1.54	0.00	0.00%	1.77%	1.72%
Rural Rate Protection Charge	427	0.0003	0.13	427	0.0003	0.13	0.00	0.00%	0.15%	0.14%
Ontario Electricity Support Program Charge	427	0.0000	0.00	427	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.29%	0.28%
Sub-Total: Regulatory			**1.91**			**1.91**	**0.00**	**0.00%**	**2.21%**	**2.15%**
Debt Retirement Charge (DRC)	400	0.000	**0.00**	400	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**81.58**			**82.64**	**1.06**	**1.30%**	**95.24%**	
HST		0.13	10.61		0.13	10.74	0.14	1.30%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**92.18**			**93.38**	**1.20**	**1.30%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.53		-0.08	-6.61	-0.08	-1.30%	-7.62%	
Total Amount on Two-Tier RPP			**85.66**			**86.77**	**1.11**	**1.30%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**83.78**			**84.84**	**1.06**	**1.27%**		**95.24%**
HST		0.13	10.89		0.13	11.03	0.14	1.27%		12.38%
Total Electricity Charge on TOU (including HST)			**94.67**			**95.87**	**1.20**	**1.27%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-6.70		-0.08	-6.79	-0.08	-1.27%		-7.62%
Total Amount on TOU			**87.97**			**89.08**	**1.11**	**1.27%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	AR
Monthly Consumption (kWh)	750
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	800
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	36.57%	
Energy Second Tier (kWh)	150	0.090	13.50	150	0.090	13.50	0.00	0.00%	10.68%	
Sub-Total: Energy (RPP)			**59.70**			**59.70**	**0.00**	**0.00%**	**47.25%**	
TOU-Off Peak	488	0.065	31.69	488	0.065	31.69	0.00	0.00%		24.76%
TOU-Mid Peak	128	0.095	12.11	128	0.095	12.11	0.00	0.00%		9.47%
TOU-On Peak	135	0.132	17.82	135	0.132	17.82	0.00	0.00%		13.93%
Sub-Total: Energy (TOU)			**61.62**			**61.62**	0.00	0.00%	**48.77%**	**48.16%**
Service Charge	1	40.43	40.43	1	41.49	41.49	1.06	2.62%	32.84%	32.43%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	750	0.0000	0.00	750	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.43**			**41.49**	**1.06**	**2.62%**	**32.84%**	**32.43%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.63%	0.62%
Line Losses on Cost of Power (based on two-tier RPP prices)	50	0.0900	4.50	50	0.0900	4.50	0.00	0.00%	3.56%	3.52%
Line Losses on Cost of Power (based on TOU prices)	50	0.0822	4.11	50	0.0822	4.11	0.00	0.00%	3.25%	3.21%
Sub-Total: Distribution (based on two-tier RPP prices)			**45.72**			**46.78**	**1.06**	**2.32%**	**37.03%**	**36.56%**
Sub-Total: Distribution (based on TOU prices)			**45.33**			**46.39**	**1.06**	**2.34%**	**36.72%**	**36.26%**
Retail Transmission Rate – Network Service Rate	800	0.0071	5.68	800	0.0071	5.68	0.00	0.00%	4.50%	4.44%
Retail Transmission Rate – Line and Transformation Connection S	800	0.0060	4.80	800	0.006	4.80	0.00	0.00%	3.80%	3.75%
Sub-Total: Retail Transmission			**10.48**			**10.48**	**0.00**	**0.00%**	**8.29%**	**8.19%**
Sub-Total: Delivery (based on two-tier RPP prices)			**56.20**			**57.26**	**1.06**	**1.89%**	**45.32%**	**44.75%**
Sub-Total: Delivery (based on TOU prices)			**55.81**			**56.87**	**1.06**	**1.90%**	**45.01%**	**44.45%**
Wholesale Market Service Rate	800	0.0036	2.88	800	0.0036	2.88	0.00	0.00%	2.28%	2.25%
Rural Rate Protection Charge	800	0.0003	0.24	800	0.0003	0.24	0.00	0.00%	0.19%	0.19%
Ontario Electricity Support Program Charge	800	0.0000	0.00	800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.20%
Sub-Total: Regulatory			**3.37**			**3.37**	**0.00**	**0.00%**	**2.67%**	**2.63%**
Debt Retirement Charge (DRC)	750	0.000	**0.00**	750	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**119.27**			**120.33**	**1.06**	**0.89%**	**95.24%**	
HST		0.13	15.51		0.13	15.64	0.14	0.89%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**134.78**			**135.98**	**1.20**	**0.89%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.54		-0.08	-9.63	-0.08	-0.89%	-7.62%	
Total Amount on Two-Tier RPP			**125.24**			**126.35**	**1.11**	**0.89%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**120.80**			**121.86**	**1.06**	**0.88%**		**95.24%**
HST		0.13	15.70		0.13	15.84	0.14	0.88%		12.38%
Total Electricity Charge on TOU (including HST)			**136.50**			**137.70**	**1.20**	**0.88%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-9.66		-0.08	-9.75	-0.08	-0.88%		-7.62%
Total Amount on TOU			**126.84**			**127.95**	**1.11**	**0.88%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AR
Monthly Consumption (kWh)	634
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	676
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	41.09%	
Energy Second Tier (kWh)	34	0.090	3.06	34	0.090	3.06	0.00	0.00%	2.72%	
Sub-Total: Energy (RPP)			**49.26**			**49.26**	**0.00**	**0.00%**	**43.81%**	
TOU-Off Peak	412	0.065	26.79	412	0.065	26.79	0.00	0.00%		23.28%
TOU-Mid Peak	108	0.095	10.24	108	0.095	10.24	0.00	0.00%		8.90%
TOU-On Peak	114	0.132	15.06	114	0.132	15.06	0.00	0.00%		13.09%
Sub-Total: Energy (TOU)			**52.09**			**52.09**	0.00	0.00%	**46.32%**	**45.27%**
Service Charge	1	40.43	40.43	1	41.49	41.49	1.06	2.62%	36.90%	36.06%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	634	0.0000	0.00	634	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	634	0.0000	0.00	634	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.43**			**41.49**	**1.06**	**2.62%**	**36.90%**	**36.06%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.70%	0.69%
Line Losses on Cost of Power (based on two-tier RPP prices)	42	0.0900	3.81	42	0.0900	3.81	0.00	0.00%	3.38%	3.31%
Line Losses on Cost of Power (based on TOU prices)	42	0.0822	3.47	42	0.0822	3.47	0.00	0.00%	3.09%	3.02%
Sub-Total: Distribution (based on two-tier RPP prices)			**45.03**			**46.09**	**1.06**	**2.35%**	**40.98%**	**40.05%**
Sub-Total: Distribution (based on TOU prices)			**44.69**			**45.75**	**1.06**	**2.37%**	**40.69%**	**39.76%**
Retail Transmission Rate – Network Service Rate	676	0.0071	4.80	676	0.0071	4.80	0.00	0.00%	4.27%	4.17%
Retail Transmission Rate – Line and Transformation Connection S	676	0.0060	4.06	676	0.006	4.06	0.00	0.00%	3.61%	3.53%
Sub-Total: Retail Transmission			**8.86**			**8.86**	**0.00**	**0.00%**	**7.88%**	**7.70%**
Sub-Total: Delivery (based on two-tier RPP prices)			**53.89**			**54.95**	**1.06**	**1.97%**	**48.86%**	**47.75%**
Sub-Total: Delivery (based on TOU prices)			**53.55**			**54.61**	**1.06**	**1.98%**	**48.57%**	**47.46%**
Wholesale Market Service Rate	676	0.0036	2.43	676	0.0036	2.43	0.00	0.00%	2.17%	2.12%
Rural Rate Protection Charge	676	0.0003	0.20	676	0.0003	0.20	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	676	0.0000	0.00	676	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.22%	0.22%
Sub-Total: Regulatory			**2.89**			**2.89**	**0.00**	**0.00%**	**2.57%**	**2.51%**
Debt Retirement Charge (DRC)	634	0.000	**0.00**	634	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**106.03**			**107.09**	**1.06**	**1.00%**	**95.24%**	
HST		0.13	13.78		0.13	13.92	0.14	1.00%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**119.82**			**121.01**	**1.20**	**1.00%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.48		-0.08	-8.57	-0.08	-1.00%	-7.62%	
Total Amount on Two-Tier RPP			**111.33**			**112.45**	**1.11**	**1.00%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**108.53**			**109.59**	**1.06**	**0.98%**		**95.24%**
HST		0.13	14.11		0.13	14.25	0.14	0.98%		12.38%
Total Electricity Charge on TOU (including HST)			**122.64**			**123.84**	**1.20**	**0.98%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-8.68		-0.08	-8.77	-0.08	-0.98%		-7.62%
Total Amount on TOU			**113.96**			**115.07**	**1.11**	**0.98%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AR
Monthly Consumption (kWh)	1800
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	600
Monthly Consumption (kWh) - Uplifted	1920
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	600	0.077	46.20	600	0.077	46.20	0.00	0.00%	18.32%	
Energy Second Tier (kWh)	1,200	0.090	108.00	1,200	0.090	108.00	0.00	0.00%	42.83%	
Sub-Total: Energy (RPP)			**154.20**			**154.20**	**0.00**	**0.00%**	**61.15%**	
TOU-Off Peak	1,170	0.065	76.05	1,170	0.065	76.05	0.00	0.00%		31.10%
TOU-Mid Peak	306	0.095	29.07	306	0.095	29.07	0.00	0.00%		11.89%
TOU-On Peak	324	0.132	42.77	324	0.132	42.77	0.00	0.00%		17.49%
Sub-Total: Energy (TOU)			**147.89**			**147.89**	**0.00**	**0.00%**	**58.64%**	**60.47%**
Service Charge	1	40.43	40.43	1	41.49	41.49	1.06	2.62%	16.45%	16.96%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,800	0.0000	0.00	1,800	0.0000	0.00	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**40.43**			**41.49**	**1.06**	**2.62%**	**16.45%**	**16.96%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.31%	0.32%
Line Losses on Cost of Power (based on two-tier RPP prices)	120	0.0900	10.81	120	0.0900	10.81	0.00	0.00%	4.28%	4.42%
Line Losses on Cost of Power (based on TOU prices)	120	0.0822	9.86	120	0.0822	9.86	0.00	0.00%	3.91%	4.03%
Sub-Total: Distribution (based on two-tier RPP prices)			**52.03**			**53.09**	**1.06**	**2.04%**	**21.05%**	**21.71%**
Sub-Total: Distribution (based on TOU prices)			**51.08**			**52.14**	**1.06**	**2.08%**	**20.68%**	**21.32%**
Retail Transmission Rate – Network Service Rate	1,920	0.0071	13.63	1,920	0.0071	13.63	0.00	0.00%	5.41%	5.57%
Retail Transmission Rate – Line and Transformation Connection S	1,920	0.0060	11.52	1,920	0.006	11.52	0.00	0.00%	4.57%	4.71%
Sub-Total: Retail Transmission			**25.15**			**25.15**	**0.00**	**0.00%**	**9.97%**	**10.28%**
Sub-Total: Delivery (based on two-tier RPP prices)			**77.18**			**78.24**	**1.06**	**1.37%**	**31.02%**	**31.99%**
Sub-Total: Delivery (based on TOU prices)			**76.24**			**77.30**	**1.06**	**1.39%**	**30.65%**	**31.61%**
Wholesale Market Service Rate	1,920	0.0036	6.91	1,920	0.0036	6.91	0.00	0.00%	2.74%	2.83%
Rural Rate Protection Charge	1,920	0.0003	0.58	1,920	0.0003	0.58	0.00	0.00%	0.23%	0.24%
Ontario Electricity Support Program Charge	1,920	0.0000	0.00	1,920	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%	0.10%
Sub-Total: Regulatory			**7.74**			**7.74**	**0.00**	**0.00%**	**3.07%**	**3.16%**
Debt Retirement Charge (DRC)	1,800	0.000	**0.00**	1,800	0.000	**0.00**	**0.00**	**N/A**	**0.00%**	**0.00%**
Total Electricty Charge on Two-Tier RPP			**239.12**			**240.18**	**1.06**	**0.44%**	**95.24%**	
HST		0.13	31.09		0.13	31.22	0.14	0.44%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**270.20**			**271.40**	**1.20**	**0.44%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-19.13		-0.08	-19.21	-0.08	-0.44%	-7.62%	
Total Amount on Two-Tier RPP			**251.07**			**252.19**	**1.11**	**0.44%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**231.86**			**232.92**	**1.06**	**0.46%**		**95.24%**
HST		0.13	30.14		0.13	30.28	0.14	0.46%		12.38%
Total Electricity Charge on TOU (including HST)			**262.01**			**263.20**	**1.20**	**0.46%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-18.55		-0.08	-18.63	-0.08	-0.46%		-7.62%
Total Amount on TOU			**243.46**			**244.57**	**1.11**	**0.46%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AUGe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1057
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	33.19%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.93%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**46.13%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		24.07%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		9.20%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.54%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**47.22%**	**46.81%**
Service Charge	1	30.26	30.26	1	36.37	36.37	6.11	20.19%	20.90%	20.72%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0174	17.40	1,000	0.0210	21.00	3.60	20.69%	12.07%	11.96%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.0000	1,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**47.66**			**57.37**	**9.71**	**20.37%**	**32.98%**	**32.69%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.45%	0.45%
Line Losses on Cost of Power (based on two-tier RPP prices)	57	0.0900	5.13	57	0.0900	5.13	0.00	0.00%	2.95%	2.92%
Line Losses on Cost of Power (based on TOU prices)	57	0.0822	4.68	57	0.0822	4.68	0.00	0.00%	2.69%	2.67%
Sub-Total: Distribution (based on two-tier RPP prices)			**53.58**			**63.29**	**9.71**	**18.12%**	**36.38%**	**36.06%**
Sub-Total: Distribution (based on TOU prices)			**53.13**			**62.84**	**9.71**	**18.27%**	**36.12%**	**35.81%**
Retail Transmission Rate – Network Service Rate	1,057	0.0056	5.92	1,057	0.0056	5.92	0.00	0.00%	3.40%	3.37%
Retail Transmission Rate – Line and Transformation Connection S	1,057	0.0046	4.86	1,057	0.0046	4.86	0.00	0.00%	2.79%	2.77%
Sub-Total: Retail Transmission			**10.78**			**10.78**	**0.00**	**0.00%**	**6.20%**	**6.14%**
Sub-Total: Delivery (based on two-tier RPP prices)			**64.36**			**74.07**	**9.71**	**15.09%**	**42.58%**	**42.20%**
Sub-Total: Delivery (based on TOU prices)			**63.91**			**73.62**	**9.71**	**15.19%**	**42.32%**	**41.95%**
Wholesale Market Service Rate	1,057	0.0036	3.81	1,057	0.0036	3.81	0.00	0.00%	2.19%	2.17%
Rural Rate Protection Charge	1,057	0.0003	0.32	1,057	0.0003	0.32	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,057	0.0000	0.00	1,057	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.37**			**4.37**	**0.00**	**0.00%**	**2.51%**	**2.49%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**4.02%**	**3.99%**
Total Electricty Charge on Two-Tier RPP			**155.98**			**165.69**	**9.71**	**6.23%**	**95.24%**	
HST		0.13	20.28		0.13	21.54	1.26	6.23%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**176.26**			**187.23**	**10.97**	**6.23%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.48		-0.08	-13.26	-0.78	-6.23%	-7.62%	
Total Amount on Two-Tier RPP			**163.78**			**173.98**	**10.20**	**6.23%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**157.45**			**167.16**	**9.71**	**6.17%**		**95.24%**
HST		0.13	20.47		0.13	21.73	1.26	6.17%		12.38%
Total Electricity Charge on TOU (including HST)			**177.91**			**188.89**	**10.97**	**6.17%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-12.60		-0.08	-13.37	-0.78	-6.17%		-7.62%
Total Amount on TOU			**165.32**			**175.51**	**10.20**	**6.17%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	AUGe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2114
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	18.11%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	35.28%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**53.38%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		27.11%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.36%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		15.24%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**51.52%**	**52.71%**
Service Charge	1	30.26	30.26	1	36.37	36.37	6.11	20.19%	11.40%	11.67%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0174	34.80	2,000	0.0210	42.00	7.20	20.69%	13.17%	13.47%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.0000	2,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**65.06**			**78.37**	**13.31**	**20.46%**	**24.57%**	**25.14%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.25%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	114	0.0900	10.26	114	0.0900	10.26	0.00	0.00%	3.22%	3.29%
Line Losses on Cost of Power (based on TOU prices)	114	0.0822	9.37	114	0.0822	9.37	0.00	0.00%	2.94%	3.00%
Sub-Total: Distribution (based on two-tier RPP prices)			**76.11**			**89.42**	**13.31**	**17.49%**	**28.04%**	**28.68%**
Sub-Total: Distribution (based on TOU prices)			**75.22**			**88.53**	**13.31**	**17.70%**	**27.76%**	**28.40%**
Retail Transmission Rate – Network Service Rate	2,114	0.0056	11.84	2,114	0.0056	11.84	0.00	0.00%	3.71%	3.80%
Retail Transmission Rate – Line and Transformation Connection S	2,114	0.0046	9.72	2,114	0.0046	9.72	0.00	0.00%	3.05%	3.12%
Sub-Total: Retail Transmission			**21.56**			**21.56**	**0.00**	**0.00%**	**6.76%**	**6.92%**
Sub-Total: Delivery (based on two-tier RPP prices)			**97.67**			**110.98**	**13.31**	**13.63%**	**34.80%**	**35.60%**
Sub-Total: Delivery (based on TOU prices)			**96.78**			**110.09**	**13.31**	**13.75%**	**34.52%**	**35.31%**
Wholesale Market Service Rate	2,114	0.0036	7.61	2,114	0.0036	7.61	0.00	0.00%	2.39%	2.44%
Rural Rate Protection Charge	2,114	0.0003	0.63	2,114	0.0003	0.63	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,114	0.0000	0.00	2,114	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.49**			**8.49**	**0.00**	**0.00%**	**2.66%**	**2.72%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.39%**	**4.49%**
Total Electricty Charge on Two-Tier RPP			**290.42**			**303.73**	**13.31**	**4.58%**	**95.24%**	
HST		0.13	37.75		0.13	39.48	1.73	4.58%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**328.17**			**343.21**	**15.04**	**4.58%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.23		-0.08	-24.30	-1.06	-4.58%	-7.62%	
Total Amount on Two-Tier RPP			**304.94**			**318.91**	**13.98**	**4.58%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**283.59**			**296.90**	**13.31**	**4.69%**		**95.24%**
HST		0.13	36.87		0.13	38.60	1.73	4.69%		12.38%
Total Electricity Charge on TOU (including HST)			**320.46**			**335.50**	**15.04**	**4.69%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-22.69		-0.08	-23.75	-1.06	-4.69%		-7.62%
Total Amount on TOU			**297.77**			**311.75**	**13.98**	**4.69%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AUGe
Monthly Consumption (kWh)	2,695
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2848.615
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	13.76%	
Energy Second Tier (kWh)	1,945	0.090	175.05	1,945	0.090	175.05	0.00	0.00%	41.71%	
Sub-Total: Energy (RPP)			**232.80**			**232.80**	**0.00**	**0.00%**	**55.48%**	
TOU-Off Peak	1,752	0.065	113.86	1,752	0.065	113.86	0.00	0.00%		28.02%
TOU-Mid Peak	458	0.095	43.52	458	0.095	43.52	0.00	0.00%		10.71%
TOU-On Peak	485	0.132	64.03	485	0.132	64.03	0.00	0.00%		15.75%
Sub-Total: Energy (TOU)			**221.42**			**221.42**	0.00	0.00%	**52.76%**	**54.48%**
Service Charge	1	30.26	30.26	1	36.37	36.37	6.11	20.19%	8.67%	8.95%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	2,695	0.0174	46.89	2,695	0.0210	56.60	9.70	20.69%	13.49%	13.92%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,695	0.0000	0.0000	2,695	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**77.15**			**92.97**	**15.81**	**20.49%**	**22.15%**	**22.87%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.19%	0.19%
Line Losses on Cost of Power (based on two-tier RPP prices)	154	0.0900	13.83	154	0.0900	13.83	0.00	0.00%	3.29%	3.40%
Line Losses on Cost of Power (based on TOU prices)	154	0.0822	12.62	154	0.0822	12.62	0.00	0.00%	3.01%	3.11%
Sub-Total: Distribution (based on two-tier RPP prices)			**91.77**			**107.58**	**15.81**	**17.23%**	**25.64%**	**26.47%**
Sub-Total: Distribution (based on TOU prices)			**90.56**			**106.38**	**15.81**	**17.46%**	**25.35%**	**26.17%**
Retail Transmission Rate – Network Service Rate	2,849	0.0056	15.95	2,849	0.0056	15.95	0.00	0.00%	3.80%	3.92%
Retail Transmission Rate – Line and Transformation Connection S	2,849	0.0046	13.10	2,849	0.0046	13.10	0.00	0.00%	3.12%	3.22%
Sub-Total: Retail Transmission			**29.06**			**29.06**	**0.00**	**0.00%**	**6.92%**	**7.15%**
Sub-Total: Delivery (based on two-tier RPP prices)			**120.82**			**136.64**	**15.81**	**13.09%**	**32.56%**	**33.62%**
Sub-Total: Delivery (based on TOU prices)			**119.62**			**135.43**	**15.81**	**13.22%**	**32.27%**	**33.32%**
Wholesale Market Service Rate	2,849	0.0036	10.26	2,849	0.0036	10.26	0.00	0.00%	2.44%	2.52%
Rural Rate Protection Charge	2,849	0.0003	0.85	2,849	0.0003	0.85	0.00	0.00%	0.20%	0.21%
Ontario Electricity Support Program Charge	2,849	0.0000	0.00	2,849	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.06%	0.06%
Sub-Total: Regulatory			**11.36**			**11.36**	**0.00**	**0.00%**	**2.71%**	**2.79%**
Debt Retirement Charge (DRC)	2,695	0.007	**18.87**	2,695	0.007	**18.87**	**0.00**	**0.00%**	**4.50%**	**4.64%**
Total Electricty Charge on Two-Tier RPP			**383.85**			**399.66**	**15.81**	**4.12%**	**95.24%**	
HST		0.13	49.90		0.13	51.96	2.06	4.12%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**433.75**			**451.62**	**17.87**	**4.12%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-30.71		-0.08	-31.97	-1.26	-4.12%	-7.62%	
Total Amount on Two-Tier RPP			**403.04**			**419.64**	**16.60**	**4.12%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**371.27**			**387.08**	**15.81**	**4.26%**		**95.24%**
HST		0.13	48.26		0.13	50.32	2.06	4.26%		12.38%
Total Electricity Charge on TOU (including HST)			**419.53**			**437.40**	**17.87**	**4.26%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-29.70		-0.08	-30.97	-1.26	-4.26%		-7.62%
Total Amount on TOU			**389.83**			**406.43**	**16.60**	**4.26%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AUGe
Monthly Consumption (kWh)	15000
Peak (kW)	0
Loss factor	1.057
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	15855
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.62%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	58.21%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**60.84%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		30.43%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.63%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		17.11%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**55.94%**	**59.17%**
Service Charge	1	30.26	30.26	1	36.37	36.37	6.11	20.19%	1.65%	1.75%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0174	261.00	15,000	0.0210	315.00	54.00	20.69%	14.30%	15.12%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.0000	15,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**291.26**			**351.37**	**60.11**	**20.64%**	**15.95%**	**16.87%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.04%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	855	0.0900	76.95	855	0.0900	76.95	0.00	0.00%	3.49%	3.69%
Line Losses on Cost of Power (based on TOU prices)	855	0.0822	70.25	855	0.0822	70.25	0.00	0.00%	3.19%	3.37%
Sub-Total: Distribution (based on two-tier RPP prices)			**369.00**			**429.11**	**60.11**	**16.29%**	**19.48%**	**20.60%**
Sub-Total: Distribution (based on TOU prices)			**362.30**			**422.41**	**60.11**	**16.59%**	**19.17%**	**20.28%**
Retail Transmission Rate – Network Service Rate	15,855	0.0056	88.79	15,855	0.0056	88.79	0.00	0.00%	4.03%	4.26%
Retail Transmission Rate – Line and Transformation Connection S	15,855	0.0046	72.93	15,855	0.0046	72.93	0.00	0.00%	3.31%	3.50%
Sub-Total: Retail Transmission			**161.72**			**161.72**	**0.00**	**0.00%**	**7.34%**	**7.76%**
Sub-Total: Delivery (based on two-tier RPP prices)			**530.72**			**590.83**	**60.11**	**11.33%**	**26.82%**	**28.37%**
Sub-Total: Delivery (based on TOU prices)			**524.02**			**584.13**	**60.11**	**11.47%**	**26.51%**	**28.05%**
Wholesale Market Service Rate	15,855	0.0036	57.08	15,855	0.0036	57.08	0.00	0.00%	2.59%	2.74%
Rural Rate Protection Charge	15,855	0.0003	4.76	15,855	0.0003	4.76	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	15,855	0.0000	0.00	15,855	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.08**			**62.08**	**0.00**	**0.00%**	**2.82%**	**2.98%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.77%**	**5.04%**
Total Electricty Charge on Two-Tier RPP			**2,038.06**			**2,098.17**	**60.11**	**2.95%**	**95.24%**	
HST		0.13	264.95		0.13	272.76	7.81	2.95%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,303.00**			**2,370.93**	**67.92**	**2.95%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-163.04		-0.08	-167.85	-4.81	-2.95%	-7.62%	
Total Amount on Two-Tier RPP			**2,139.96**			**2,203.07**	**63.12**	**2.95%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**1,923.50**			**1,983.61**	**60.11**	**3.13%**		**95.24%**
HST		0.13	250.06		0.13	257.87	7.81	3.13%		12.38%
Total Electricity Charge on TOU (including HST)			**2,173.56**			**2,241.48**	**67.92**	**3.13%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-153.88		-0.08	-158.69	-4.81	-3.13%		-7.62%
Total Amount on TOU			**2,019.68**			**2,082.79**	**63.12**	**3.13%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AGSe
Monthly Consumption (kWh)	1000
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	1066.7
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	31.95%	
Energy Second Tier (kWh)	250	0.090	22.50	250	0.090	22.50	0.00	0.00%	12.45%	
Sub-Total: Energy (RPP)			**80.25**			**80.25**	**0.00**	**0.00%**	**44.39%**	
TOU-Off Peak	650	0.065	42.25	650	0.065	42.25	0.00	0.00%		23.19%
TOU-Mid Peak	170	0.095	16.15	170	0.095	16.15	0.00	0.00%		8.86%
TOU-On Peak	180	0.132	23.76	180	0.132	23.76	0.00	0.00%		13.04%
Sub-Total: Energy (TOU)			**82.16**			**82.16**	0.00	0.00%	**45.45%**	**45.09%**
Service Charge	1	40.92	40.92	1	43.26	43.26	2.34	5.72%	23.93%	23.74%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	1,000	0.0188	18.80	1,000	0.0201	20.10	1.30	6.91%	11.12%	11.03%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,000	0.0000	0.0000	1,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**59.72**			**63.36**	**3.64**	**6.10%**	**35.05%**	**34.77%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.44%	0.43%
Line Losses on Cost of Power (based on two-tier RPP prices)	67	0.0900	6.00	67	0.0900	6.00	0.00	0.00%	3.32%	3.29%
Line Losses on Cost of Power (based on TOU prices)	67	0.0822	5.48	67	0.0822	5.48	0.00	0.00%	3.03%	3.01%
Sub-Total: Distribution (based on two-tier RPP prices)			**66.51**			**70.15**	**3.64**	**5.47%**	**38.81%**	**38.50%**
Sub-Total: Distribution (based on TOU prices)			**65.99**			**69.63**	**3.64**	**5.52%**	**38.52%**	**38.21%**
Retail Transmission Rate – Network Service Rate	1,067	0.0053	5.65	1,067	0.0053	5.65	0.00	0.00%	3.13%	3.10%
Retail Transmission Rate – Line and Transformation Connection S	1,067	0.0044	4.69	1,067	0.0044	4.69	0.00	0.00%	2.60%	2.58%
Sub-Total: Retail Transmission			**10.35**			**10.35**	**0.00**	**0.00%**	**5.72%**	**5.68%**
Sub-Total: Delivery (based on two-tier RPP prices)			**76.86**			**80.50**	**3.64**	**4.74%**	**44.53%**	**44.18%**
Sub-Total: Delivery (based on TOU prices)			**76.34**			**79.98**	**3.64**	**4.77%**	**44.24%**	**43.89%**
Wholesale Market Service Rate	1,067	0.0036	3.84	1,067	0.0036	3.84	0.00	0.00%	2.12%	2.11%
Rural Rate Protection Charge	1,067	0.0003	0.32	1,067	0.0003	0.32	0.00	0.00%	0.18%	0.18%
Ontario Electricity Support Program Charge	1,067	0.0000	0.00	1,067	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.14%	0.14%
Sub-Total: Regulatory			**4.41**			**4.41**	**0.00**	**0.00%**	**2.44%**	**2.42%**
Debt Retirement Charge (DRC)	1,000	0.007	**7.00**	1,000	0.007	**7.00**	**0.00**	**0.00%**	**3.87%**	**3.84%**
Total Electricty Charge on Two-Tier RPP			**168.52**			**172.16**	**3.64**	**2.16%**	**95.24%**	
HST		0.13	21.91		0.13	22.38	0.47	2.16%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**190.43**			**194.54**	**4.11**	**2.16%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.48		-0.08	-13.77	-0.29	-2.16%	-7.62%	
Total Amount on Two-Tier RPP			**176.95**			**180.77**	**3.82**	**2.16%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**169.91**			**173.55**	**3.64**	**2.14%**		**95.24%**
HST		0.13	22.09		0.13	22.56	0.47	2.14%		12.38%
Total Electricity Charge on TOU (including HST)			**192.00**			**196.11**	**4.11**	**2.14%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-13.59		-0.08	-13.88	-0.29	-2.14%		-7.62%
Total Amount on TOU			**178.40**			**182.22**	**3.82**	**2.14%**		**100.00%**

2022 Bill Impacts (Typical Consumption Level)

Rate Class	AGSe
Monthly Consumption (kWh)	2000
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2133.4
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.76%	
Energy Second Tier (kWh)	1,250	0.090	112.50	1,250	0.090	112.50	0.00	0.00%	34.59%	
Sub-Total: Energy (RPP)			**170.25**			**170.25**	**0.00**	**0.00%**	**52.34%**	
TOU-Off Peak	1,300	0.065	84.50	1,300	0.065	84.50	0.00	0.00%		26.58%
TOU-Mid Peak	340	0.095	32.30	340	0.095	32.30	0.00	0.00%		10.16%
TOU-On Peak	360	0.132	47.52	360	0.132	47.52	0.00	0.00%		14.95%
Sub-Total: Energy (TOU)			**164.32**			**164.32**	0.00	0.00%	**50.52%**	**51.68%**
Service Charge	1	40.92	40.92	1	43.26	43.26	2.34	5.72%	13.30%	13.61%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	2,000	0.0188	37.60	2,000	0.0201	40.20	2.60	6.91%	12.36%	12.64%
Volumetric Deferral/Variance Account Rider (including CBR Class	2,000	0.0000	0.0000	2,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**78.52**			**83.46**	**4.94**	**6.29%**	**25.66%**	**26.25%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	133	0.0900	12.01	133	0.0900	12.01	0.00	0.00%	3.69%	3.78%
Line Losses on Cost of Power (based on TOU prices)	133	0.0822	10.96	133	0.0822	10.96	0.00	0.00%	3.37%	3.45%
Sub-Total: Distribution (based on two-tier RPP prices)			**91.32**			**96.26**	**4.94**	**5.41%**	**29.59%**	**30.28%**
Sub-Total: Distribution (based on TOU prices)			**90.27**			**95.21**	**4.94**	**5.47%**	**29.27%**	**29.95%**
Retail Transmission Rate – Network Service Rate	2,133	0.0053	11.31	2,133	0.0053	11.31	0.00	0.00%	3.48%	3.56%
Retail Transmission Rate – Line and Transformation Connection S	2,133	0.0044	9.39	2,133	0.0044	9.39	0.00	0.00%	2.89%	2.95%
Sub-Total: Retail Transmission			**20.69**			**20.69**	**0.00**	**0.00%**	**6.36%**	**6.51%**
Sub-Total: Delivery (based on two-tier RPP prices)			**112.01**			**116.95**	**4.94**	**4.41%**	**35.96%**	**36.78%**
Sub-Total: Delivery (based on TOU prices)			**110.96**			**115.90**	**4.94**	**4.45%**	**35.63%**	**36.46%**
Wholesale Market Service Rate	2,133	0.0036	7.68	2,133	0.0036	7.68	0.00	0.00%	2.36%	2.42%
Rural Rate Protection Charge	2,133	0.0003	0.64	2,133	0.0003	0.64	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,133	0.0000	0.00	2,133	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.57**			**8.57**	**0.00**	**0.00%**	**2.63%**	**2.70%**
Debt Retirement Charge (DRC)	2,000	0.007	**14.00**	2,000	0.007	**14.00**	**0.00**	**0.00%**	**4.30%**	**4.40%**
Total Electricty Charge on Two-Tier RPP			**304.83**			**309.77**	**4.94**	**1.62%**	**95.24%**	
HST		0.13	39.63		0.13	40.27	0.64	1.62%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**344.46**			**350.04**	**5.58**	**1.62%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.39		-0.08	-24.78	-0.40	-1.62%	-7.62%	
Total Amount on Two-Tier RPP			**320.07**			**325.26**	**5.19**	**1.62%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**297.85**			**302.79**	**4.94**	**1.66%**		**95.24%**
HST		0.13	38.72		0.13	39.36	0.64	1.66%		12.38%
Total Electricity Charge on TOU (including HST)			**336.58**			**342.16**	**5.58**	**1.66%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.83		-0.08	-24.22	-0.40	-1.66%		-7.62%
Total Amount on TOU			**312.75**			**317.93**	**5.19**	**1.66%**		**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AGSe
Monthly Consumption (kWh)	1,988
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	2121
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	17.85%	
Energy Second Tier (kWh)	1,238	0.090	111.42	1,238	0.090	111.42	0.00	0.00%	34.44%	
Sub-Total: Energy (RPP)			**169.17**			**169.17**	**0.00**	**0.00%**	**52.29%**	
TOU-Off Peak	1,292	0.065	83.99	1,292	0.065	83.99	0.00	0.00%		26.55%
TOU-Mid Peak	338	0.095	32.11	338	0.095	32.11	0.00	0.00%		10.15%
TOU-On Peak	358	0.132	47.23	358	0.132	47.23	0.00	0.00%		14.93%
Sub-Total: Energy (TOU)			**163.33**			**163.33**	0.00	0.00%	**50.49%**	**51.64%**
Service Charge	1	40.92	40.92	1	43.26	43.26	2.34	5.72%	13.37%	13.68%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	1,988	0.0188	37.37	1,988	0.0201	39.96	2.58	6.91%	12.35%	12.63%
Volumetric Deferral/Variance Account Rider (including CBR Class	1,988	0.0000	0.0000	1,988	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**78.29**			**83.22**	**4.92**	**6.29%**	**25.72%**	**26.31%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.24%	0.25%
Line Losses on Cost of Power (based on two-tier RPP prices)	133	0.0900	11.93	133	0.0900	11.93	0.00	0.00%	3.69%	3.77%
Line Losses on Cost of Power (based on TOU prices)	133	0.0822	10.89	133	0.0822	10.89	0.00	0.00%	3.37%	3.44%
Sub-Total: Distribution (based on two-tier RPP prices)			**91.02**			**95.94**	**4.92**	**5.41%**	**29.66%**	**30.33%**
Sub-Total: Distribution (based on TOU prices)			**89.98**			**94.90**	**4.92**	**5.47%**	**29.33%**	**30.00%**
Retail Transmission Rate – Network Service Rate	2,121	0.0053	11.24	2,121	0.0053	11.24	0.00	0.00%	3.47%	3.55%
Retail Transmission Rate – Line and Transformation Connection S	2,121	0.0044	9.33	2,121	0.0044	9.33	0.00	0.00%	2.88%	2.95%
Sub-Total: Retail Transmission			**20.57**			**20.57**	**0.00**	**0.00%**	**6.36%**	**6.50%**
Sub-Total: Delivery (based on two-tier RPP prices)			**111.59**			**116.51**	**4.92**	**4.41%**	**36.01%**	**36.84%**
Sub-Total: Delivery (based on TOU prices)			**110.55**			**115.47**	**4.92**	**4.45%**	**35.69%**	**36.51%**
Wholesale Market Service Rate	2,121	0.0036	7.63	2,121	0.0036	7.63	0.00	0.00%	2.36%	2.41%
Rural Rate Protection Charge	2,121	0.0003	0.64	2,121	0.0003	0.64	0.00	0.00%	0.20%	0.20%
Ontario Electricity Support Program Charge	2,121	0.0000	0.00	2,121	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.08%
Sub-Total: Regulatory			**8.52**			**8.52**	**0.00**	**0.00%**	**2.63%**	**2.69%**
Debt Retirement Charge (DRC)	1,988	0.007	**13.92**	1,988	0.007	**13.92**	**0.00**	**0.00%**	**4.30%**	**4.40%**
Total Electricty Charge on Two-Tier RPP			**303.19**			**308.12**	**4.92**	**1.62%**	**95.24%**	
HST		0.13	39.42		0.13	40.06	0.64	1.62%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**342.61**			**348.17**	**5.56**	**1.62%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-24.26		-0.08	-24.65	-0.39	-1.62%	-7.62%	
Total Amount on Two-Tier RPP			**318.35**			**323.52**	**5.17**	**1.62%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**296.32**			**301.24**	**4.92**	**1.66%**		**95.24%**
HST		0.13	38.52		0.13	39.16	0.64	1.66%		12.38%
Total Electricity Charge on TOU (including HST)			**334.84**			**340.41**	**5.56**	**1.66%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-23.71		-0.08	-24.10	-0.39	-1.66%		-7.62%
Total Amount on TOU			**311.13**			**316.31**	**5.17**	**1.66%**		**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AGSe
Monthly Consumption (kWh)	15,000
Peak (kW)	0
Loss factor	1.0667
Commodity Threshold	750
Monthly Consumption (kWh) - Uplifted	16000.5
Charge determinant	kWh

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill on RPP	% of Total Bill on TOU
Energy First Tier (kWh)	750	0.077	57.75	750	0.077	57.75	0.00	0.00%	2.62%	
Energy Second Tier (kWh)	14,250	0.090	1,282.50	14,250	0.090	1,282.50	0.00	0.00%	58.20%	
Sub-Total: Energy (RPP)			**1,340.25**			**1,340.25**	**0.00**	**0.00%**	**60.82%**	
TOU-Off Peak	9,750	0.065	633.75	9,750	0.065	633.75	0.00	0.00%		30.44%
TOU-Mid Peak	2,550	0.095	242.25	2,550	0.095	242.25	0.00	0.00%		11.63%
TOU-On Peak	2,700	0.132	356.40	2,700	0.132	356.40	0.00	0.00%		17.12%
Sub-Total: Energy (TOU)			**1,232.40**			**1,232.40**	0.00	0.00%	**55.93%**	**59.19%**
Service Charge	1	40.92	40.92	1	43.26	43.26	2.34	5.72%	1.96%	2.08%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%	0.00%
Distribution Volumetric Rate	15,000	0.0188	282.00	15,000	0.0201	301.50	19.50	6.91%	13.68%	14.48%
Volumetric Deferral/Variance Account Rider (including CBR Class	15,000	0.0000	0.0000	15,000	0.0000	0.0000	0.00	N/A	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			**322.92**			**344.76**	**21.84**	**6.76%**	**15.65%**	**16.56%**
Smart Metering Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.04%	0.04%
Line Losses on Cost of Power (based on two-tier RPP prices)	1,001	0.0900	90.05	1,001	0.0900	90.05	0.00	0.00%	4.09%	4.32%
Line Losses on Cost of Power (based on TOU prices)	1,001	0.0822	82.20	1,001	0.0822	82.20	0.00	0.00%	3.73%	3.95%
Sub-Total: Distribution (based on two-tier RPP prices)			**413.76**			**435.60**	**21.84**	**5.28%**	**19.77%**	**20.92%**
Sub-Total: Distribution (based on TOU prices)			**405.91**			**427.75**	**21.84**	**5.38%**	**19.41%**	**20.54%**
Retail Transmission Rate – Network Service Rate	16,001	0.0053	84.80	16,001	0.0053	84.80	0.00	0.00%	3.85%	4.07%
Retail Transmission Rate – Line and Transformation Connection S	16,001	0.0044	70.40	16,001	0.0044	70.40	0.00	0.00%	3.19%	3.38%
Sub-Total: Retail Transmission			**155.20**			**155.20**	**0.00**	**0.00%**	**7.04%**	**7.45%**
Sub-Total: Delivery (based on two-tier RPP prices)			**568.96**			**590.80**	**21.84**	**3.84%**	**26.81%**	**28.37%**
Sub-Total: Delivery (based on TOU prices)			**561.12**			**582.96**	**21.84**	**3.89%**	**26.45%**	**28.00%**
Wholesale Market Service Rate	16,001	0.0036	57.60	16,001	0.0036	57.60	0.00	0.00%	2.61%	2.77%
Rural Rate Protection Charge	16,001	0.0003	4.80	16,001	0.0003	4.80	0.00	0.00%	0.22%	0.23%
Ontario Electricity Support Program Charge	16,001	0.0000	0.00	16,001	0.0000	0.00	0.00	N/A	0.00%	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%	0.01%
Sub-Total: Regulatory			**62.65**			**62.65**	**0.00**	**0.00%**	**2.84%**	**3.01%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.76%**	**5.04%**
Total Electricty Charge on Two-Tier RPP			**2,076.86**			**2,098.70**	**21.84**	**1.05%**	**95.24%**	
HST		0.13	269.99		0.13	272.83	2.84	1.05%	12.38%	
Total Electricity Charge on Two-Tier RPP (including HST)			**2,346.85**			**2,371.53**	**24.68**	**1.05%**	**107.62%**	
Rebate equal to Ontario portion of HST (8%)		-0.08	-166.15		-0.08	-167.90	-1.75	-1.05%	-7.62%	
Total Amount on Two-Tier RPP			**2,180.70**			**2,203.64**	**22.93**	**1.05%**	**100.00%**	
Total Electricty Charge on TOU (before HST)			**1,961.17**			**1,983.01**	**21.84**	**1.11%**		**95.24%**
HST		0.13	254.95		0.13	257.79	2.84	1.11%		12.38%
Total Electricity Charge on TOU (including HST)			**2,216.12**			**2,240.80**	**24.68**	**1.11%**		**107.62%**
Rebate equal to Ontario portion of HST (8%)		-0.08	-156.89		-0.08	-158.64	-1.75	-1.11%		-7.62%
Total Amount on TOU			**2,059.23**			**2,082.16**	**22.93**	**1.11%**		**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AUGd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.047
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,698
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change ($)	% of Total Bill
Energy First Tier (kWh)	15,698	0.077	1,208.71	15,698	0.077	1,208.71	0.00	0.00%	49.10%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,208.71**			**1,208.71**	**0.00**	**0.00%**	**49.10%**
Service Charge	1	207.78	207.78	1	283.62	283.62	75.84	36.50%	11.52%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	60	3.9916	239.50	60	5.2968	317.81	78.31	32.70%	12.91%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0000	0.00	60	0.0000	0.00	0.00	N/A	0.00%
Volumetric Global Adjustment Account Rider	15,698	0.0000	0.00	15,698	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**447.28**			**601.43**	**154.15**	**34.46%**	**24.43%**
Retail Transmission Rate – Network Service Rate	60	1.8612	111.67	60	1.8612	111.67	0.00	0.00%	4.54%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.5062	90.37	60	1.5062	90.37	0.00	0.00%	3.67%
Sub-Total: Retail Transmission			**202.04**			**202.04**	**0.00**	**0.00%**	**8.21%**
Sub-Total: Delivery			**649.32**			**803.47**	**154.15**	**23.74%**	**32.64%**
Wholesale Market Service Rate	15,698	0.0036	56.51	15,698	0.0036	56.51	0.00	0.00%	2.30%
Rural Rate Protection Charge	15,698	0.0003	4.71	15,698	0.0003	4.71	0.00	0.00%	0.19%
Ontario Electricity Support Program Charge	15,698	0.0000	0.00	15,698	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**61.47**			**61.47**	**0.00**	**0.00%**	**2.50%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.27%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,024.50**			**2,178.65**	**154.15**	**7.61%**	**88.50%**
HST		0.13	263.18		0.13	283.22	20.04	7.61%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,287.68**			**2,461.87**	**174.19**	**7.61%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,287.68**			**2,461.87**	**174.19**	**7.61%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AUGd
Monthly Consumption (kWh)	61,239
Peak (kW)	177
Loss factor	1.047
Load factor	47%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	64,087
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change ($)	% of Total Bill
Energy First Tier (kWh)	64,087	0.077	4,934.67	64,087	0.077	4,934.67	0.00	0.00%	58.77%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,934.67**			**4,934.67**	**0.00**	**0.00%**	**58.77%**
Service Charge	1	207.78	207.78	1	283.62	283.62	75.84	36.50%	3.38%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	177	3.9916	706.51	177	5.2968	937.53	231.02	32.70%	11.17%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	177	0.0000	0.00	177	0.0000	0.00	0.00	N/A	0.00%
Volumetric Global Adjustment Account Rider	64,087	0.0000	0.00	64,087	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**914.29**			**1,221.15**	**306.86**	**33.56%**	**14.54%**
Retail Transmission Rate – Network Service Rate	177	1.8612	329.43	177	1.8612	329.43	0.00	0.00%	3.92%
Retail Transmission Rate – Line and Transformation Connection Service Rate	177	1.5062	266.60	177	1.5062	266.60	0.00	0.00%	3.18%
Sub-Total: Retail Transmission			**596.03**			**596.03**	**0.00**	**0.00%**	**7.10%**
Sub-Total: Delivery			**1,510.32**			**1,817.18**	**306.86**	**20.32%**	**21.64%**
Wholesale Market Service Rate	64,087	0.0036	230.71	64,087	0.0036	230.71	0.00	0.00%	2.75%
Rural Rate Protection Charge	64,087	0.0003	19.23	64,087	0.0003	19.23	0.00	0.00%	0.23%
Ontario Electricity Support Program Charge	64,087	0.0000	0.00	64,087	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**250.19**			**250.19**	**0.00**	**0.00%**	**2.98%**
Debt Retirement Charge (DRC)	61,239	0.007	**428.67**	61,239	0.007	**428.67**	**0.00**	**0.00%**	**5.11%**
Total Electricity Charge on Two-Tier RPP (before HST)			**7,123.85**			**7,430.71**	**306.86**	**4.31%**	**88.50%**
HST		0.13	926.10		0.13	965.99	39.89	4.31%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**8,049.95**			**8,396.71**	**346.75**	**4.31%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**8,049.95**			**8,396.71**	**346.75**	**4.31%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AUGd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.047
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	183,138
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change ($)	% of Total Bill
Energy First Tier (kWh)	183,138	0.077	14,101.59	183,138	0.077	14,101.59	0.00	0.00%	60.41%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,101.59**			**14,101.59**	**0.00**	**0.00%**	**60.41%**
Service Charge	1	207.78	207.78	1	283.62	283.62	75.84	36.50%	1.22%
Fixed Deferral/Variance Account Rider	1	0.000	0.00	1	0.000	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	500	3.9916	1,995.80	500	5.2968	2,648.40	652.60	32.70%	11.35%
Volumetric Global Adjustment Account Rider	183,138	0.0000	0.00	183,138	0.0000	0.00	0.00	N/A	0.00%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0	0.00	500	0	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,203.58**			**2,932.02**	**728.44**	**33.06%**	**12.56%**
Retail Transmission Rate – Network Service Rate	500	1.8612	930.60	500	1.8612	930.60	0.00	0.00%	3.99%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.5062	753.10	500	1.5062	753.10	0.00	0.00%	3.23%
Sub-Total: Retail Transmission			**1,683.70**			**1,683.70**	**0.00**	**0.00%**	**7.21%**
Sub-Total: Delivery			**3,887.28**			**4,615.72**	**728.44**	**18.74%**	**19.77%**
Wholesale Market Service Rate	183,138	0.0036	659.30	183,138	0.0036	659.30	0.00	0.00%	2.82%
Rural Rate Protection Charge	183,138	0.0003	54.94	183,138	0.0003	54.94	0.00	0.00%	0.24%
Ontario Electricity Support Program Charge	183,138	0.0000	0.00	183,138	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**714.49**			**714.49**	**0.00**	**0.00%**	**3.06%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**5.25%**
Total Electricity Charge on Two-Tier RPP (before HST)			**19,928.35**			**20,656.79**	**728.44**	**3.66%**	**88.50%**
HST		0.13	2,590.69		0.13	2,685.38	94.70	3.66%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**22,519.04**			**23,342.18**	**823.14**	**3.66%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**22,519.04**			**23,342.18**	**823.14**	**3.66%**	**100.00%**

2022 Bill Impacts (Low Consumption Level)

Rate Class	AGSd
Monthly Consumption (kWh)	15,000
Peak (kW)	60
Loss factor	1.056
Load factor	34%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	15,845
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	15,845	0.077	1,220.03	15,845	0.077	1,220.03	0.00	0.00%	48.51%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**1,220.03**			**1,220.03**	**0.00**	**0.00%**	**48.51%**
Service Charge	1	206.23	206.23	1	252.41	252.41	46.18	22.39%	10.04%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	60	5.249	314.94	60	6.4095	384.57	69.63	22.11%	15.29%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	60	0.0000	0.00	60	0.0000	0.00	0.00	N/A	0.00%
Volumetric Global Adjustment Account Rider	15,845	0.0000	0.00	15,845	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**521.17**			**636.98**	**115.81**	**22.22%**	**25.33%**
Retail Transmission Rate – Network Service Rate	60	1.8483	110.90	60	1.8483	110.90	0.00	0.00%	4.41%
Retail Transmission Rate – Line and Transformation Connection Service Rate	60	1.5101	90.61	60	1.5101	90.61	0.00	0.00%	3.60%
Sub-Total: Retail Transmission			**201.50**			**201.50**	**0.00**	**0.00%**	**8.01%**
Sub-Total: Delivery			**722.67**			**838.48**	**115.81**	**16.03%**	**33.34%**
Wholesale Market Service Rate	15,845	0.0036	57.04	15,845	0.0036	57.04	0.00	0.00%	2.27%
Rural Rate Protection Charge	15,845	0.0003	4.75	15,845	0.0003	4.75	0.00	0.00%	0.19%
Ontario Electricity Support Program Charge	15,845	0.0000	0.00	15,845	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.01%
Sub-Total: Regulatory			**62.04**			**62.04**	**0.00**	**0.00%**	**2.47%**
Debt Retirement Charge (DRC)	15,000	0.007	**105.00**	15,000	0.007	**105.00**	**0.00**	**0.00%**	**4.18%**
Total Electricity Charge on Two-Tier RPP (before HST)			**2,109.74**			**2,225.55**	**115.81**	**5.49%**	**88.50%**
HST		0.13	274.27		0.13	289.32	15.06	5.49%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**2,384.01**			**2,514.88**	**130.87**	**5.49%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**2,384.01**			**2,514.88**	**130.87**	**5.49%**	**100.00%**

2022 Bill Impacts (Average Consumption Level)

Rate Class	AGSd
Monthly Consumption (kWh)	53,895
Peak (kW)	152
Loss factor	1.056
Load factor	49%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	56,929
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	56,929	0.077	4,383.56	56,929	0.077	4,383.56	0.00	0.00%	57.73%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**4,383.56**			**4,383.56**	**0.00**	**0.00%**	**57.73%**
Service Charge	1	206.23	206.23	1	252.41	252.41	46.18	22.39%	3.32%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	152	5.249	797.85	152	6.4095	974.24	176.40	22.11%	12.83%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	152	0.0000	0.00	152	0	0.00	0.00	N/A	0.00%
Volumetric Global Adjustment Account Rider	56,929	0.0000	0.00	56,929	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**1,004.08**			**1,226.65**	**222.58**	**22.17%**	**16.15%**
Retail Transmission Rate – Network Service Rate	152	1.8483	280.94	152	1.8483	280.94	0.00	0.00%	3.70%
Retail Transmission Rate – Line and Transformation Connection Service Rate	152	1.5101	229.54	152	1.5101	229.54	0.00	0.00%	3.02%
Sub-Total: Retail Transmission			**510.48**			**510.48**	**0.00**	**0.00%**	**6.72%**
Sub-Total: Delivery			**1,514.55**			**1,737.13**	**222.58**	**14.70%**	**22.88%**
Wholesale Market Service Rate	56,929	0.0036	204.95	56,929	0.0036	204.95	0.00	0.00%	2.70%
Rural Rate Protection Charge	56,929	0.0003	17.08	56,929	0.0003	17.08	0.00	0.00%	0.22%
Ontario Electricity Support Program Charge	56,929	0.0000	0.00	56,929	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**222.27**			**222.27**	**0.00**	**0.00%**	**2.93%**
Debt Retirement Charge (DRC)	53,895	0.007	**377.27**	53,895	0.007	**377.27**	**0.00**	**0.00%**	**4.97%**
Total Electricity Charge on Two-Tier RPP (before HST)			**6,497.65**			**6,720.23**	**222.58**	**3.43%**	**88.50%**
HST		0.13	844.69		0.13	873.63	28.93	3.43%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**7,342.34**			**7,593.85**	**251.51**	**3.43%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**7,342.34**			**7,593.85**	**251.51**	**3.43%**	**100.00%**

2022 Bill Impacts (High Consumption Level)

Rate Class	AGSd
Monthly Consumption (kWh)	175,000
Peak (kW)	500
Loss factor	1.056
Load factor	48%
Commodity Threshold	0
Monthly Consumption (kWh) - Uplifted	184,853
Charge determinant	kW

	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total Bill
Energy First Tier (kWh)	184,853	0.077	14,233.64	184,853	0.077	14,233.64	0.00	0.00%	59.09%
Energy Second Tier (kWh)	0	0.090	0.00	0	0.090	0.00	0.00	N/A	0.00%
Sub-Total: Energy (RPP)			**14,233.64**			**14,233.64**	**0.00**	**0.00%**	**59.09%**
Service Charge	1	206.23	206.23	1	252.41	252.41	46.18	22.39%	1.05%
Fixed Deferral/Variance Account Rider	1	0.00	0.00	1	0.00	0.00	0.00	N/A	0.00%
Distribution Volumetric Rate	500	5.249	2,624.50	500	6.4095	3,204.75	580.25	22.11%	13.30%
Volumetric Deferral/Variance Account Rider (including CBR Class B rider)	500	0.0000	0.00	500	0	0.00	0.00	N/A	0.00%
Volumetric Global Adjustment Account Rider	184,853	0.0000	0.00	184,853	0.0000	0.00	0.00	N/A	0.00%
Sub-Total: Distribution			**2,830.73**			**3,457.16**	**626.43**	**22.13%**	**14.35%**
Retail Transmission Rate – Network Service Rate	500	1.8483	924.15	500	1.8483	924.15	0.00	0.00%	3.84%
Retail Transmission Rate – Line and Transformation Connection Service Rate	500	1.5101	755.05	500	1.5101	755.05	0.00	0.00%	3.13%
Sub-Total: Retail Transmission			**1,679.20**			**1,679.20**	**0.00**	**0.00%**	**6.97%**
Sub-Total: Delivery			**4,509.93**			**5,136.36**	**626.43**	**13.89%**	**21.32%**
Wholesale Market Service Rate	184,853	0.0036	665.47	184,853	0.0036	665.47	0.00	0.00%	2.76%
Rural Rate Protection Charge	184,853	0.0003	55.46	184,853	0.0003	55.46	0.00	0.00%	0.23%
Ontario Electricity Support Program Charge	184,853	0.0000	0.00	184,853	0.0000	0.00	0.00	N/A	0.00%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			**721.17**			**721.17**	**0.00**	**0.00%**	**2.99%**
Debt Retirement Charge (DRC)	175,000	0.007	**1,225.00**	175,000	0.007	**1,225.00**	**0.00**	**0.00%**	**5.09%**
Total Electricity Charge on Two-Tier RPP (before HST)			**20,689.75**			**21,316.18**	**626.43**	**3.03%**	**88.50%**
HST		0.13	2,689.67		0.13	2,771.10	81.44	3.03%	11.50%
Total Electricity Charge on Two-Tier RPP (including HST)			**23,379.41**			**24,087.28**	**707.87**	**3.03%**	**100.00%**
Rebate equal to Ontario portion of HST (8%)		0.00	0.00		0.00	0.00	0.00	N/A	0.00%
Total Amount on Two-Tier RPP			**23,379.41**			**24,087.28**	**707.87**	**3.03%**	**100.00%**

Power Workers' Union Interrogatory # 5

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

Q-01-01-01 Page: 21

Interrogatory:

a) Do the Total Bill Impacts reflected on the table take account of the FHP?

b) If not, why not?

c) If so, what is the basis of the bill impacts listed for 2019-22? Provide illustrative examples of the calculation of the bill impacts for each year of the application. Please indicate what assumptions have been made, and the basis for those assumptions.

Response:

a) No, the Total Bill impacts shown in the referenced table do not take account of the FHP.

b) The bill impacts provided in the referenced table are intended to show the impact of Hydro One's proposed increase in its distribution revenue requirement and the proposed changes in its load forecast. This is consistent with how Hydro One expects the OEB to assess the impact of its rate application. The OEB requires distributors to show the impact of their proposed rate increases holding all other bill components such as electricity and regulatory charges constant.

c) See response to b). Illustrative calculations of bill impacts are provided in Exhibit H1, Tab 4, Schedule 1, Attachments 2 through 5.

Power Workers' Union Interrogatory # 6

Issue:
Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:
Ref (a): The June 15, 2017 Hydro One presentation materials at the OEB Townhall (https://www.hydroone.com/abouthydroone/RegulatoryInformation/AboutOurRateApplication/Documents/OEB_Townhall_Presentation_June_15.pdf) address the bill impacts of the application in light of the FHP. At Slide 8, there is a reference to $1.95 in monthly charges to a representative customer in respect of "Flow through transmission costs not covered by FHP".

Interrogatory:
a) What are these costs, and why are they not covered by the FHP?

b) Are the bill impacts referenced in the evidence inclusive of these costs?

c) What would the bill impacts be, if these costs were covered by the FHP?

Response:
a) Flow through transmission costs refers to Retail Transmission Service Rates ("RTSR"), which are variable charges that appear on distribution customers' bills for the costs of transmitters to operate and maintain the high-voltage transmission system that carries electricity from generating stations to the distributor.

   Ontario Regulation 198/17, which describes the Distribution Rate Protection component of the FHP, only provides a subsidy to limit customers' base distribution charges to a capped amount (currently at $36.43 per month). Flow through transmission costs, or RTSR, are not affected by this Regulation.

b) Yes, the bill impact tables in the evidence include RTSR charges.

c) The scope of the Fair Hydro Plan, as set out in the Fair Hydro Act and associated regulations, does not allow for subsidizing flow through transmission costs.

Power Workers' Union Interrogatory # 7

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

B1-01-01 Section 1.3 Page: 4-15 (Customer engagement process)

Interrogatory:

a) Please confirm that this process was undertaken prior to the FHP coming into effect?

b) Did Hydro One undertake any additional customer engagement activities (in particular regarding the bill impact of the application) after the implementation of the FHP? If so:

   i. describe the initiatives that were undertaken;
   ii. describe the feedback received; and
   iii. describe the manner in which any feedback was incorporated into the application in its current form.

Response:

a) The Customer Engagement process was undertaken prior to the Fair Hydro Plan coming into effect.

b) Hydro One did not undertake additional customer engagement activities after the implementation of the Fair Hydro Plan.

Balsam Lake Coalition Interrogatory # 4

Issue:

Issue 5: Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?

Reference:

https://www.hydroone.com/rates-and-billing/fair-hydro-plan

Interrogatory:

Hydro One's website asserts the following:

> Under the Fair Hydro Plan, the majority of our customers will see an average reduction of 31 per cent on their monthly bills, meaning an annual savings of about $600*.
>
> We also advocated for Distribution Rate Protection for our rural customers who will now see delivery charges fall in line with urban delivery rates. This relief will be long-lasting.

a) Please confirm that Distribution Rate Protection is not and will not be extended to customers that Hydro One includes in the Seasonal Rate Class.

b) Please provide any documentation submitted by Hydro One to the provincial government with respect to Hydro One's advocacy for Distribution Rate Protection for its rural customers. Please confirm whether or not Hydro One's advocacy included advocating for Distribution Rate Protection (or any other relief) for Hydro One's Seasonal Customers (i.e. customers currently identified by Hydro One as Seasonal Customers and included as members in the Seasonal Rate Class), either in the context of those customers continuing to be included in the existing Seasonal Rate Class, or in the context of those customers migrating to the existing R1 and R2 classes upon the elimination of the Seasonal Class pursuant to the Board's direction in EB-2013-0416.

c) Whether or not Hydro One advocated for Distribution Rate Protection or any other relief for Seasonal Customers, please provide any documentation exchanged between Hydro One and the provincial government that demonstrates that the provincial government considered any proposals to extend Distribution Rate Protection or other relief to Seasonal Customers.

d) To the extent Hydro One advocated on behalf of Seasonal Customers and/or to the extent the issue of Distribution Rate Protection (or any other relief) for Seasonal Customers was considered by the provincial government, please provide the rationale provided to Hydro One by the provincial government for excluding Seasonal Customers from Distribution Rate Protection and the lack of any other form of relief for seasonal customers. To the extent any such rationale was communicated in writing please provide copies of any documentation of that rationale.

Response:

a) Confirmed.

b) Please see the attached white paper on "Addressing Affordability" provided by Hydro One to the government of Ontario. Hydro One did not specifically reference our Seasonal customers but many of the proposals in the attached white paper also benefit Seasonal customers.

c) Hydro One advocated for rate reductions and affordable electricity for all customers (as outlined in Part b).

d) Hydro One was part of the Ministry of Energy working group that provided input to the ministry staff that developed the Distribution Rate Protection component of the Fair Hydro Plan. Hydro One informed ministry staff of the OEB's decisions with respect to the elimination of the Seasonal class and potential for seasonal customers being included in Hydro One's R1 and R2 year round residential rate classes.

ADDRESSING AFFORDABILITY

JANUARY 30, 2017

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INTRODUCTION

Transitioning from a Crown corporation to a publically traded company, the focus at Hydro One is on continuous improvement of all aspects of the business. While customer service is paramount at Hydro One, these improvements also include finding ways to drive further efficiencies in the utilization of transmission and distribution assets, reducing costs and improving reliability. This focus will invariably deliver value to customers, employees, communities and shareholders alike. There are, however, broader issues related to the affordability of electricity which need to be addressed in order to fully realize the benefits of this transition.

We know our customers are struggling; we have been visiting communities across the province and listening to their concerns face-to-face. As a Company that maintains a direct relationship with over 25% of electricity customers in Ontario, Hydro One continues to witness firsthand the effects of rising electricity rates. Initially, these concerns were predominately high bill complaints that were resolved by providing explanations and education. Today, an unfortunate trend has developed where electricity charges have exceeded customers' means of payment, and explanations and education cannot resolve issues of affordability. This is especially apparent within Hydro One's customer base wherein rural and Northern residential, including First Nations, customers and small businesses consume electricity at proportionally higher rates than in urban environments and, in many cases, use electricity for heating. Unfortunately, after exhausting all options, the Company is often required by regulation to make the difficult decision to disconnect service. This "final" conclusion, however, is not final for Hydro One, as we must continue to adapt our business, and advocate for our customers until all have access to programs and rates that make our essential service affordable.

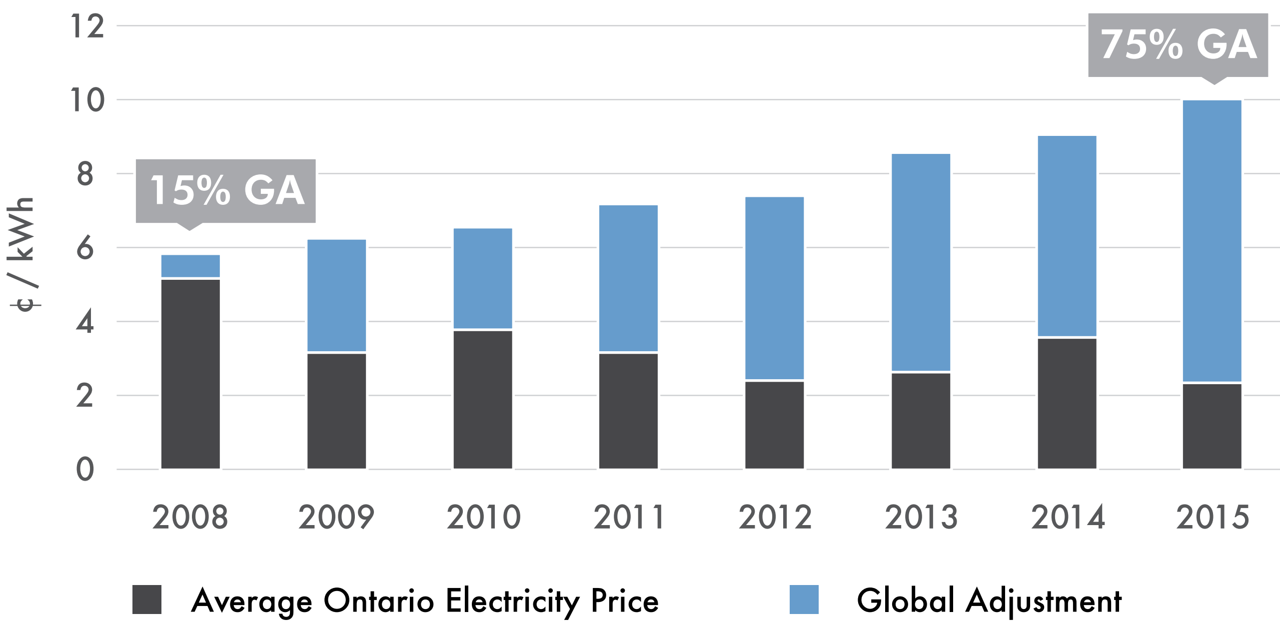
The most obvious sign of our commitment to serve and advocate for our customers was the introduction of our Winter Relief Program. Winter Relief got the lights back on in time for winter for those who had been disconnected. Our focus now turns towards determining what it would take to keep the lights on for those customers – in a sustainable and affordable manner. For these reasons, the Government of Ontario's intention to take bold measures to bring rate relief to our customers is highly supported by Hydro One.

Hydro One recognizes that reducing rates is a highly complex matter especially within a system where most of the costs are determined through contracts and regulation. The affordability challenge resides with those who manage and participate in the electricity sector. This report contains Hydro One's recommendations to the Government of Ontario on how to reduce electricity costs, remove systemic inequities for rural and Northern customers, and provide additional measures to assist customers on an individual basis. These recommendations reflect the voices of many of our customers struggling to afford their monthly electricity bills, and who are often put in a position to make a decision between heat and food.

GLOBAL ADJUSTMENT

Since 2008, the market price for electricity has dramatically declined due to a drop in demand, but also an increase in supply through new generation contracts. The effect of the low market price has, consequently, resulted in a dramatic increase of Global Adjustment (GA), which is now the dominant and fastest-growing component of electricity rates. The GA has risen from $3.8 billion in 2010 to nearly $11 billion in 2016. Today, the GA accounts for 76% of the average residential customer's electricity charges. Figure 1 illustrates this escalation in the GA.

FIGURE 1: CURRENT ELECTRICITY PRICING TRENDS



Source: IESO

> With respect to the affordability of electricity, the Global Adjustment cannot be ignored in terms of cost drivers, appropriation of costs and government policy.

Power purchase agreements, or generation contracts, are the primary cost driver for the GA. The vast majority of these contracts were signed for a 20 year period, which means that prices should not begin to decline for at least another 15 years. Amortizing these costs over a longer period of time, 30 or 40 years, would create a rate smoothing effect. While renegotiating contracts is not advisable, other financial instruments could be created to facilitate this amortization.

Another important consideration is the composition of expenses in the GA, and the question of whether or not some of these expenses are more appropriately funded by tax payers. For example, the strategy to transition Ontario's electricity supply mix to more carbon neutral alternatives, such as wind and solar, had many benefits to all Ontarians beyond the supply of electricity – notably, environmental, social and economic development. As such, an argument could reasonably be made that tax payers should fund elements of the GA related to green energy contracts. There are other similar broadly beneficial initiatives that are being funded by electricity consumers, such as conservation and demand management, and it is recommended that the Government consider re-appropriating these costs through other means, such as through general accounts and the proceeds of cap and trade.

The final consideration with respect to the GA relates to government policy; specifically the Industrial Conservation Initiative (ICI) that is placing substantial upward pressure on residential and small business electricity prices. The ICI is a program that allows large power consumers to reduce their GA payments by conserving electricity. The ICI program measures a participant's level of consumption at five peak hours throughout the year. The IESO determines the five peak hours based on system demand and the participants are not informed of the system peak until after it has been declared. A participants average consumption during the five peak periods determines the amount of GA they will pay the following year. Companies that are able to predict the peaks and either curtail their consumption, or generate their own electricity during a peak time can save millions in GA payments. While Hydro One fully supports our largest customers and the significant role they play as the economic engine of Ontario, we have observed many ICI participants substantially reducing their GA contributions by an average of 40%, and some by as much as 97%. The direct results of these ICI GA savings result in further costs being absorbed by residential and small business customers through rates increases. In 2010, prior to the ICI program, Regulated Rate Plan consumers (predominately residential and small business) were funding 39% of the total GA. Today, RPP consumers are funding 46% of the total GA, which is equivalent to an additional $800M annually.

Due to increasing active participation by industry in the ICI program, and a recent expansion of program eligibility by the government, **Hydro One's ICI-eligible customers will climb from 50 to 200**. It is anticipated there will be an increasing trend in GA cost shifting from industry that will place a higher burden on residential customers and small businesses. We recommend that the Government of Ontario re-examine the ICI program and consider placing reasonable limits on how much residential and small business consumers contribute to this program.

SUMMARY OF SOLUTIONS TO REDUCE THE GLOBAL ADJUSTMENT INCLUDE:

- Increasing the amortization of generation contract payments by way of financial instruments;
- Conducting a detailed analysis of rate-payer funded policies that benefit the province as a whole and appropriate a portion of those costs back to the tax base; and
- Placing reasonable limits on Regulated Price Plan consumers' contribution toward the Industrial Conservation Initiative.

Depending on the type of tactics employed, potential savings are illustrated in Figure 2.

FIGURE 2: TRANSLATING GLOBAL ADJUSTMENT SAVINGS INTO POTENTIAL BILL SAVINGS FOR AVERAGE RPP CONSUMERS

Reduction in Global Adjustment	Monthly Savings for Residential Customers	Reduction in Monthly Bill For Hydro One R2 Customer
15%	$9.45	5.7%
30%	$18.97	11.5%
50%	$31.68	19.2%
100%	$63.37	38.4%

Note: The Regulated Price Plan (residential and small business consumers) share of the total Global Adjustment is estimated to cost $5 billion, or $84.50/MWH. The monthly savings for residential and small business customers is based on an average usage of 750kWh/month.

SYSTEM COSTS

Electricity rates are designed and set with the purpose of recovering system costs. System costs are large¬ly fixed either by contract or regulation. For instance, Hydro One is regulated by the Ontario Energy Board (OEB) and our delivery charges are set according to their cost-to-serve model. The dominating factor in the cost-to-serve model is ratebase, which represents an accumulation of capital investments in the system over time and cannot be changed if the system is to oper¬ate reliably. As a result, the existing regulatory model leaves little flexibility to reduce delivery charges, however, it does provide a significant level of oversight to ensure the rates represent the cost to serve.

The broader electricity system, however, does have great opportunities for cost savings through the consolidation of local distribution companies (LDCs). In the 2012 Report of the Ontario Distribution Sector Review Panel, *"Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First"*, the Panel recommended that Ontario's 73 LDCs "should be consolidated into 8-12 larger regional distributors that are large enough to deliver improved efficiency and enhanced customer focus, while at the same time maintaining a strong connection with their local communities". In the first ten years after consolidation, the Panel estimated that $1.7 billion in costs could be removed from the electricity distribution sector which would be equivalent to approximately $70/annum for every electricity customer by the end of the tenth year.

A similar report in 2012, the *Commission on the Reform of Ontario's Public Services*, authored by Don Drummond, also recommended that the government "Consolidate Ontario's 80 local distribution companies (LDCs) along regional lines to create economies of scale. Reducing the $1.35 billion spent on operations, maintenance and administrative costs for Ontario's LDCs would result in direct savings on the delivery portion of the electricity bill".

Unfortunately, voluntary consolidation has been limited since 2012 and these potential savings remain locked up by municipally-owned utilities. It is likely that these savings can only be unlocked for consumers with the help of government. It is our recommendation that the Government of Ontario revisit options at its disposal to facilitate further consolidation to achieve maximum savings for electricity consumers.

CUSTOMER CONCERNS

RURAL DELIVERY RATES

Hydro One's customers pay considerably higher delivery charges as a result of the OEB's cost allocation principles. The principles have created an obvious urban-rural divide over delivery charges. The delivery charge is predominately comprised of two components, transmission charges and distribution charges. The distribution charges vary between LDCs and are the driver of the rate inequity between urban and rural consumers. For example, some LDCs can charge their customers $15/month for distribution charges, while Hydro One must charge its average residential customer $58/month based on the cost-to-serve model. Hydro One's costs are driven by servicing rural and remote Ontario, where our customer density is very low compared to other LDCs, which serve regions with higher customer densities. If distribution charges were applied equally among all consumers in Ontario, the average charge would be approximately $38/month, which would require many consumers to pay more; clearly not the intent of the Government of Ontario at this time. Recognizing that $38/month is the average distribution charge, Hydro One recommends provid¬ing additional rate relief to rural and Northern customers to bring their distribution charges in line with the average in Ontario. This would require an additional $200M in rate subsidy for Hydro One's rural non-seasonal customers.

In addition to introducing fair and reasonable rates for rural customers, it is also recommended that Hydro One expedite the transition to fixed distribution charges. The OEB has mandated that all LDCs remove the variable (volumetric) components of the distribution charge and transition to a fixed distribution charge. Fixed charges will benefit higher energy consumers, such as those who heat with electricity; however, it will also cause lower volume consumers to pay more. The transition to a fixed rate will occur incrementally until 2023 in order to avoid rate shock for the many consumers who will end up paying more. Hydro One proposes that additional rate relief could be provided to allow higher consumers to have their distribution charges 100% fixed immediately. We know that many low income families heat with electricity and would greatly benefit from this early transition. The estimated cost of advancing fixed rates would be approximately $90M/year and ultimately decline to $0 by 2023.

In total, Hydro One proposes that approximately $290M in rate relief from the Government of Ontario would not only make delivery rates more affordable, but also introduce rate fairness to rural consumers.

STRUGGLING CUSTOMERS

Electricity bills for low-density customers can represent up to 18% of household net income. Similar to other LDCs, Hydro One is limited in its ability to offer relief to customers who cannot afford to pay their electricity bills. The Company is able to waive security deposits and allow longer payment times but due to regulatory limitations we cannot forgive overdue accounts until a disconnection has taken place. Hydro One proposes that it be given the flexibility and autonomy to quickly respond to these customers' needs for support ahead of taking the drastic step of disconnection, which is itself a costly measure for the Company. Disconnection and reconnection, which can cost upward of $2000, can be avoided.

Hydro One has several highly effective conservation programs that are only available to customers who meet the mandated definition of "low income consumers". Allowing Hydro One to offer these programs at its discretion to struggling consumers who do not or cannot qualify as low income would allow the Company to resolve acute cases of hardship and in many cases avoid disconnection. Examples of programs to be offered include whole home weatherization and appliance replacement ranging from $3,500-5,500/customer or installing cold climate air source heat pump for homes heated with electricity ranging from $7,000-$13,000/customer. It is recommended that the Government of Ontario consider establishing an Affordability Fund for LDCs to access as a means to help struggling consumers who cannot qualify for low income programs and cannot upgrade their homes without financial assistance. Over time this program would save on disconnection costs, and help struggling customers get back on track.

A final consideration for struggling consumers relates to opportunities for the Ontario Electricity Support Program (OESP). Presently the OESP is undersubscribed with approximately 30% of eligible families participating. Hydro One recommends changes to the program requirements such as removing the number of occupants, to allow more consumers to qualify. Alternatively, surpluses could be directed to the Affordability Fund described above.

RECOMMENDATIONS

1

The Government of Ontario should aggressively reduce the GA and give consideration to applying reductions to residential and small business consumers' portion of the GA. It should also consider re-appropriating GA costs to the tax base for programs which have broader social benefit. Finally, it should consider limiting the funding of the ICI program by residential and small business consumers.

2

After four years of facilitating voluntary consolidation, the Government of Ontario should eliminate barriers and stimulate consolidation of LDCs to remove $1.7 billion costs from the distribution sector.

3

The Government of Ontario should remove delivery charge rate inequity by providing additional rate relief to rural customers by bringing their distribution charges in line with the provincial average.

4

The Government of Ontario should establish an Affordability Fund (potentially funded from surpluses collected under the OESP) for LDCs to access so that Hydro One can provide relief to customers suffering from acute hardship who do not qualify as low income assistance.

STACKING THE BENEFITS OF PROPOSED RATE RELIEF MEASURES

TARGET AUDIENCE	ALL RESIDENTIAL AND SMALL BUSINESS CONSUMERS IN ONTARIO	RURAL AND NORTHERN HYDRO ONE CUSTOMERS	HYDRO ONE CUSTOMERS WITH ELECTRIC HEAT	STRUGGLING CUSTOMERS
HYDRO ONE'S RECOMMENDATIONS	30% reduction in Global Adjustment applied to residential and small business customers *50% RPP savings = $2.5B 100% RPP savings = $5B	Provide rural and Northern customers with a fair delivery rate, closer to the provincial average	Expedite the transition to fixed distribution charges	Expand eligibility requirements for the Ontario Electricity Support Program
ESTIMATED ANNUAL PROGRAM COST	$1.5B	$200M	$90M in 2017 to $0 in 2023	$0
STACKING THE BENEFITS	$19/mo	$18/mo	$30/mo* *declining to $0 in 2023	$75/mo* *electrically heated
TOTAL SAVINGS PER MONTH	$19	$37	$66	$142

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CONCLUSION

Taken as a whole, the recommendations provided by Hydro One will increase affordability both over the short and long term for consumers, meaningfully addressing affordability of electricity. By putting our customers first and advocating on their behalf, the Company presents compelling advice, backed with evidence and rationale to make a difference for our customers. From addressing the inequities associated with the GA and delivery charges, to identifying potential cost savings in the distribution system and providing additional targeted support for struggling customers, these realistic and tangible recommendations address customer concerns and, if implemented, will ensure that no one in Ontario has to choose between heat and food.

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Anwaatin Inc. Interrogatory # 1

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

A-04
A-04-02

Preamble:

Hydro One's distribution business serves the majority of the First Nations and Métis communities in Ontario.

In the Application, Hydro One states that it will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities (increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work).

Hydro One indicates that, through its First Nations and Métis Strategy (Exhibit A, Tab 4, Schedule 2), communities would like to see an increase in procurement, investment/ownership opportunities, and other business partnership opportunities for Aboriginal businesses. Hydro One further indicates that First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in Northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.

Hydro One also notes that First Nations communities and customers feel they are disproportionately impacted by high electricity costs. Many have raised concerns that their delivery charge is higher than their electricity consumption. In addition, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive.

Hydro One indicates that it hopes to address many of the Indigenous concerns with reliability and distributed energy resources, including Indigenous investment and ownership, and is developing a consolidated framework to guide First Nations and Métis relations and engagement across all lines of business.

Interrogatory:

a) Please describe how Hydro One consulted First Nations on any and all investment/ownership opportunities and other business partnership opportunities related to DERs in grid-connected communities, and what resulted from these consultation efforts.

b) Please describe in detail and provide all reports, notes, memos and documents related to:

   i. all processes Hydro One undertook to consult with Indigenous communities on this distribution rate application; and
   ii. the outcome of those consultations.

c) Please list each and all distributed energy resources that:

   i. Hydro One considered for Indigenous communities;
   ii. Hydro One consulted with First Nations on;
   iii. Hydro One implemented or intends to implement for Indigenous communities;
   iv. the Hydro One actions that result from them; and
   v. the quantified improvements in reliability and service that result from them.

d) Since First Nations in Ontario have now acquired or will soon acquire more than 14 million shares of Hydro One (representing 2.4% of the outstanding common shares of Hydro One), please describe how Hydro One will address the significant concerns of Indigenous shareholders relating to the high frequency and duration of power outages in Indigenous communities and the disparate reliability afforded to this class of shareholder.

Response:

a) Hydro One engages First Nations on investment/ownership opportunities on a project by project basis such as the Bruce to Milton Transmission Project and the Niagara Reinforcement Project. At this time, Hydro One has not yet engaged First Nations on any investment/ownership opportunities and other business partnership opportunities related to distributed energy resources (DERs) in grid-connected communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

b)

i) Hydro One regularly engages with First Nations and Métis communities about various issues of concern.

As part of its review of customer needs and preferences, Hydro One conducted a telephone survey in August 2016 of a random and representative sample of 300 First Nations customers. A key finding was that First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. A copy of the telephone survey results with First Nations customers can be found EB-2017-0049, Exhibit B1-1-1, Section 1.3, Attachment 1, pages 1562 to 1570.

In addition, Hydro One also held engagement sessions with (a) the 88 First Nation communities it serves on February 9 and 10, 2017, the session reports for which are provided as Attachment 4 to section 1.3 of the DSP (Exhibit B1, Tab 1, Schedule 1) and (b) the 29 Métis Councils represented by the Métis Nation of Ontario on May 13, 2017. The purpose of the sessions was to engage on Application as well as to share information on various programs and initiatives benefiting Indigenous communities and to hear about issues and concerns expressed by participants as they related to Hydro One. Please find enclosed reports, presentations, and notes related to these engagement sessions as Attachments 1 to 9.

Hydro One will be hosting a second First Nations Engagement Session on February 21, 2018 which will be open to representatives of the 88 First Nations communities it serves. A similar engagement session will be offered to the Métis Nation of Ontario in 2018.

ii) For the most part, Hydro One had existing initiatives in place to address the concerns raised in these engagement sessions. Hydro One made 35 specific commitments at the

February 9 and 10, 2017 First Nation engagement session and 95% of these commitments were addressed throughout the year. Hydro One made 10 specific commitments at the May 13, 2017 engagement session with the Métis Nation of Ontario. Attachment 10 lists the 10 questions asked by the Métis Nation of Ontario and includes Hydro One responses.

The outcomes of these engagement sessions was the development of additional strategies and plans responsive to the key issues and concerns expressed by participants as they related to the transmission and distribution system.

To improve affordability, Hydro One implemented an outreach plan to ensure all eligible First Nation customers benefit from the First Nations Delivery Credit announced as part of the Ontario Fair Hydro Plan and which came into effect on July 1, 2017. Hydro One also adjusted a plan to implement the First Nations Conservation Program (FNCP) in new First Nation communities in 2018. The FNCP is a follow-up program to the Aboriginal Conservation Program which was implemented by the Independent Electricity System Operator (IESO) and ended in 2015 after providing services to 39 communities. The FNCP is designed to serve the communities not served by the IESO's earlier program**.**

In addition, Hydro One also implemented the Get Local Initiative to help customers by providing information about conservation programs and resources that may assist low-income customers and ensuring that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program. Finally, in 2018 Hydro One started to roll-out the Affordability Fund to improve First Nations' home energy efficiency by providing free energy-saving upgrades, which can lower home energy use and, correspondingly, a customer's electricity bill over the long term.

In order to improve reliability and in response to complaints raised at the engagement sessions, Hydro One has revised its vegetation management policy whereby it will increase the frequency of forestry maintenance work on reserve. In addition, on measures to improve reliability, please see parts c) i), ii), and iii) of Exhibit I-6-Anwaatin-2.

On liability and access, Hydro One responded to feed-back committing to notify or seek permission as applicable from First Nation communities when conducting reconnection work on reserve in the context of its distribution business.

c) Hydro One has not yet considered distributed energy resources related to Indigenous communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

d) Hydro One will continue to invest in its assets according to asset condition assessments without regard to preferences of specific shareholders.

Hydro One and First Nations Engagement Session

February 9th & 10th, 2017

DISCLAIMERS

In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or any other entity contained in this presentation are intended only to illustrate past performance of such entitles and are not necessarily indicative of future performance of Hydro One. In this presentation, "Hydro One" refers to Hydro One Limited and its subsidiaries and other investments, taken together as a whole.

Forward-Looking Information

This presentation contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements related to project costs; statements related to continued consolidation of the electric utility market; statements related to dividends, including expectations regarding the ability of continued rate base expansion through capital investments to drive growth in dividends; statements regarding future equity issuances; expectations regarding funding for planned capital investments; statements related to rate applications and models; statements regarding rate base and cash flows; and statements regarding productivity improvements.

Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target", and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this presentation is based on a variety of factors and assumptions, as described in the financial statements and management's discussion and analysis. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One's business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are described in the financial statements and management's discussion and analysis.

Non-GAAP Measures

Hydro One prepares and presents its financial statements in accordance with U.S. GAAP. "Funds from Operations" or "FFO" and "Adjusted Earnings Per Share" are not recognized measures under U.S. GAAP and do not have standardized meanings prescribed by U.S. GAAP. These are therefore unlikely to be comparable to similar measures presented by other companies. Funds from Operations should not be considered in isolation nor as a substitute for analysis of Hydro One's financial information reported under U.S. GAAP. "Funds from Operations" or "FFO" is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) non-controlling interest distributions. Management believes that these measures will be helpful as a supplemental measure of the Company's operating cash flows and earnings. For more information, see "Non-GAAP Measures" in Hydro One's 2016 full year MD&A.

Thursday, February 9th 2017 - Agenda

Hydro One and First Nations Engagement Session
Thursday, February 9, 2017
8:30 a.m. - 4:30 p.m.

Session Objectives: We would like to come together to share mutual aspirations and hear from you about the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board

Item	Speaker	Start Time	Duration
Welcome • Introduction to Today's Session • Introduction of First Nations' Elder (Andrew Wesley) • Prayer from Elder	Phil Goulais & Elder	8:30am	30 mins
Introductory Remarks • Hydro One's Commitment to First Nations (including recent success stories)	Mayo Schmidt	9:00am	30 mins
Individual Introductions • Introduction of each Chief or Delegate • Open Discussion "What would you like to get out of today's session?"	Phil Goulais	9:30am	60 mins
BREAK		**10:30am**	**15 mins**
Customer Service • Customer Vision, Strategy, & Key Initiatives • Faciliated Dialogue: Exercise at each table. "What does great Customer Service mean to you"	Ferio Pugliese	10:45am	90 mins
NETWORKING LUNCH		**12:15pm**	**45 mins**
Distribution Rate Filing (2018-2022) • Key Findings from Customer Consultation • Revenue Requirement and Distribution Rate Profile • Cost Allocation Methodology, Rate Design	Oded Hubert & Henry Andre	1:00pm	90 mins
BREAK		**2:30pm**	**15 mins**
System Investments • Education about why the power goes out • Reliability statistics on FN communities (either a few sample communities or in aggregiate) • Investments in the Dx Rate Filing which will help to improve reliability (i.e. worst feeder)	Greg Kiraly	2:45pm	60 mins
Wrap Up • Feedback • Protocol for Future Discussions	Phil Goulais	3:45pm	30 mins

Friday, Feb 10th 2017 - Agenda

Hydro One and First Nations Engagement Session
Friday February 10, 2017
8:30 a.m. - 4:30 p.m.

hydro one

Session Objectives: We would like to come together to share mutual aspirations and hear from you about the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board

Item	Speaker	Start Time	Duration
Welcome • Introduction to Today's Session • Introduction of First Nations' Elder (Andrew Wesley) • Prayer from Elder	Phil Goulais & Elder	8:30am	30 mins
Individual Introductions • Introduction of each Chief or Delegate • Open Discussion "What would you like to get out of today's session?"	Phil Goulais	9:00am	60 mins
BREAK		**10:00am**	**15 mins**
Customer Service • Customer Vision, Strategy, & Key Initiatives • Faciliated Dialogue: Exercise at each table. "What does great Customer Service mean to you"	Ferio Pugliese	10:15am	60 mins
CEO Remarks • Hydro One's Commitment to First Nations (including recent success stories)	Mayo Schmidt	11:30am	30 mins
NETWORKING LUNCH		**12:00pm**	**30 mins**
System Investments • Education about why the power goes out • Reliability statistics on FN communities (either a few sample communities or in aggregiate) • Investments in the Dx Rate Filing which will help to improve reliability (i.e. worst feeder)	Greg Kiraly	2:45pm	60 mins
BREAK		**2:30pm**	**15 mins**
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Wrap Up • Feedback • Protocol for Future Discussions	Phil Goulais	3:45pm	30 mins

Customer Service

Ferio Pugliese

Executive Vice President, Customer Care and Corporate Affairs

Hydro One and First Nations Engagement Session

February 9 and 10, 2017

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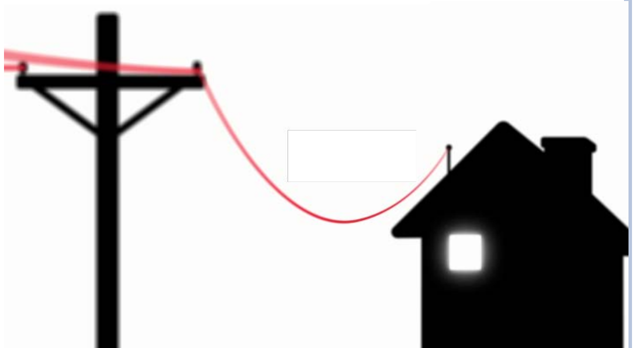
Customer Service Vision

- We are easy to do business with
- We are there when customers need us
- We are always connected

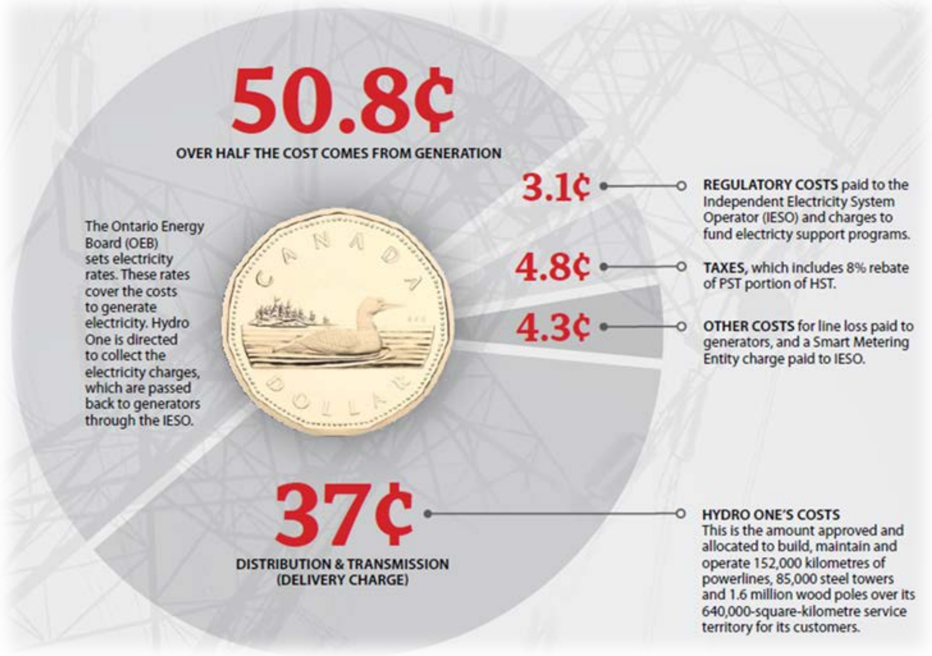


We Are Easy To Do Business With

Education

Advocacy

Responsiveness



We Are There When Customers Need Us

Local presence

First Nations Engagement

Responding in ways you prefer

In-Community Sessions

Face-to-Face Interactions

Province-Wide

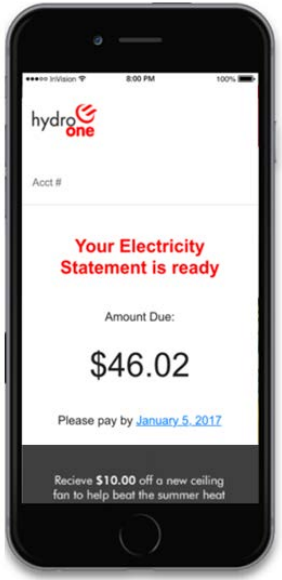
Program Enrollment

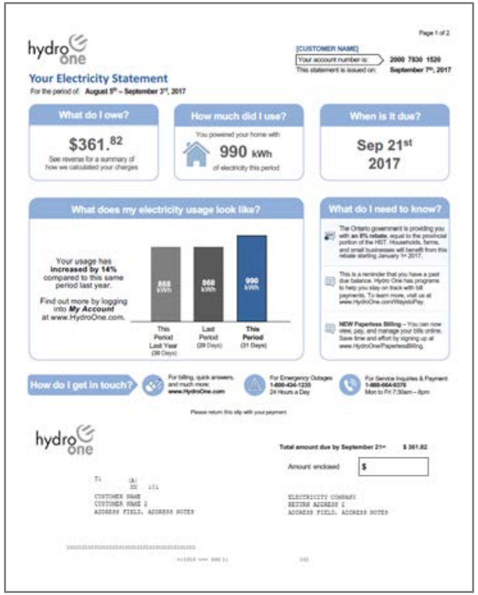
We Are Always Connected

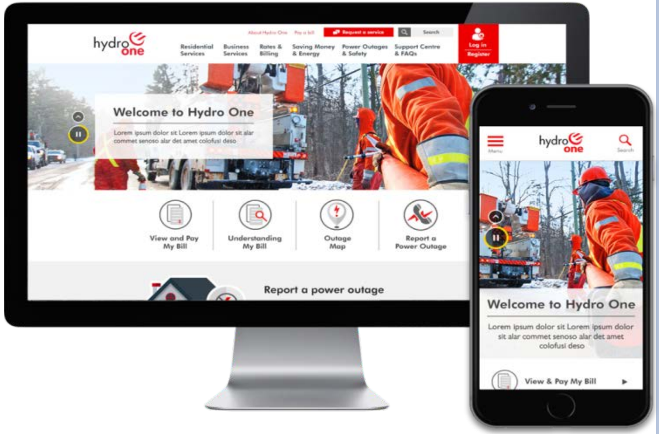
eBill Notifications & High Usage Alerts

New Website

Redesigned Bill







Our Commitment to You

Be present where we can

Listen and advocate on your behalf

Partner and respond

First Nations Reliability Performance Overview

Greg Kiraly and Mike Penstone

Hydro One and First Nations Engagement Session

February 9 & 10, 2017

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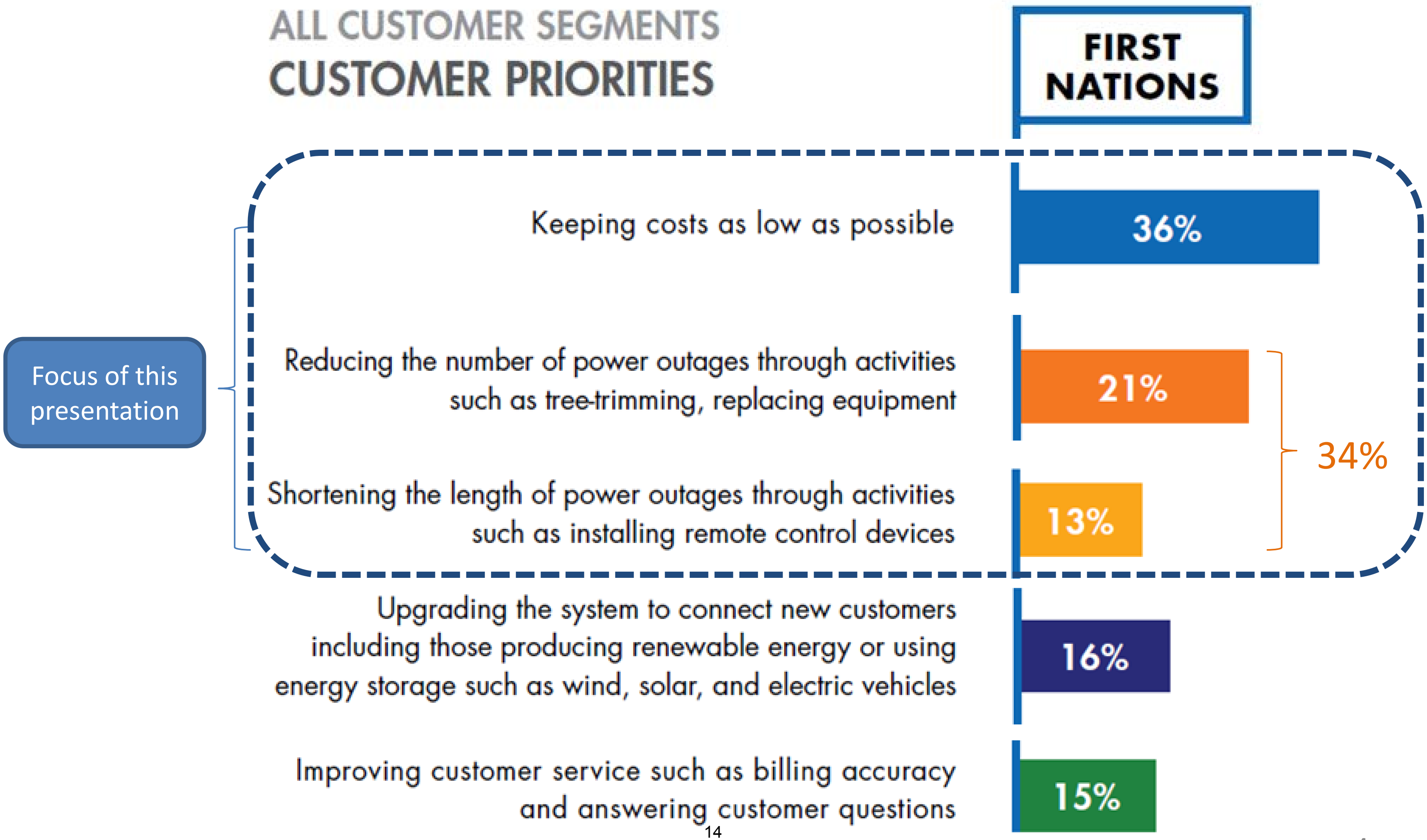
Today's Presentation

- Customer Engagement Initiative
- Reliability to First Nations Communities
- Managing Costs

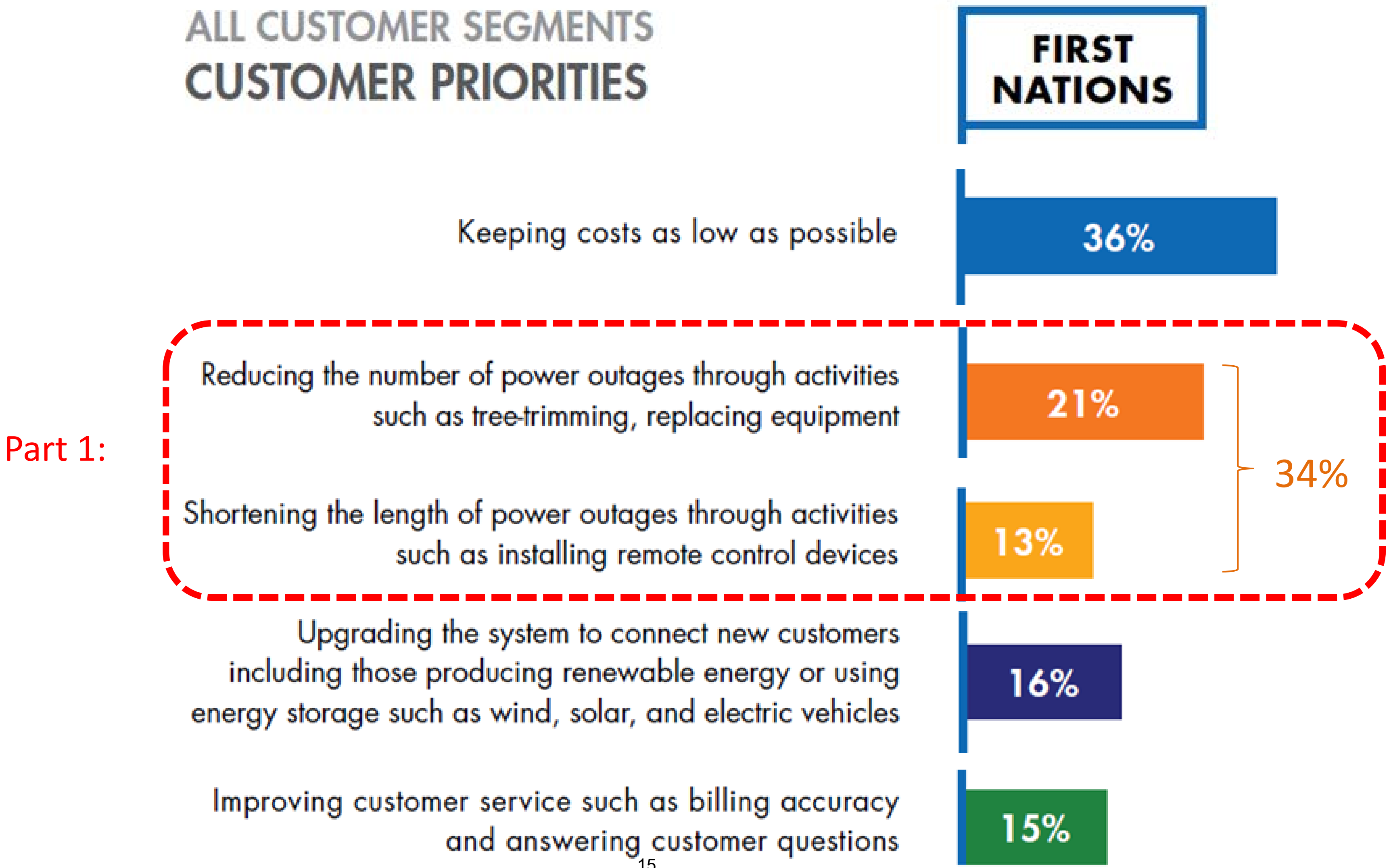
Customer Engagement Initiative

- Occurred in Q2 2016
- A 3rd party facilitated the initiative
- Input received from 300 First Nations Customers

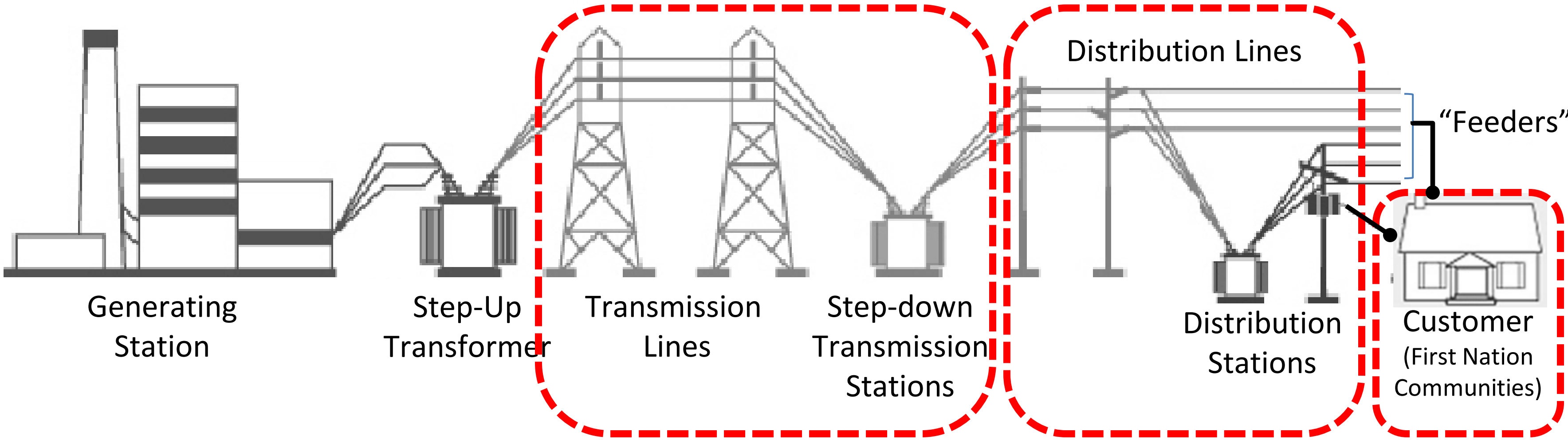
Customer Engagement Results



Customer Engagement Results



Generation → Customer

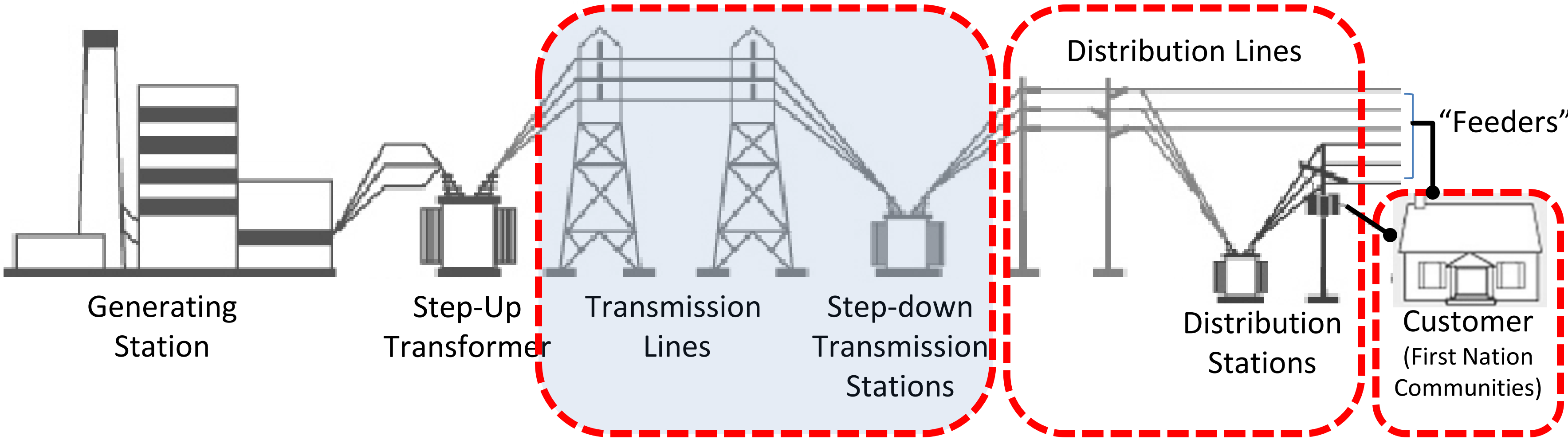


1 **Transmission System:** ~490 Transmission Lines, ~340 Transmission Stations, 29,000 km of Transmission Lines

2 **Distribution System:** ~3200 Distribution Lines, ~1000 Distribution Stations, 130,000 km of Distribution Lines

3 **First Nation Communities:** Supplied from 55 Transmission Lines and from 89 Distribution Lines

Transmission System



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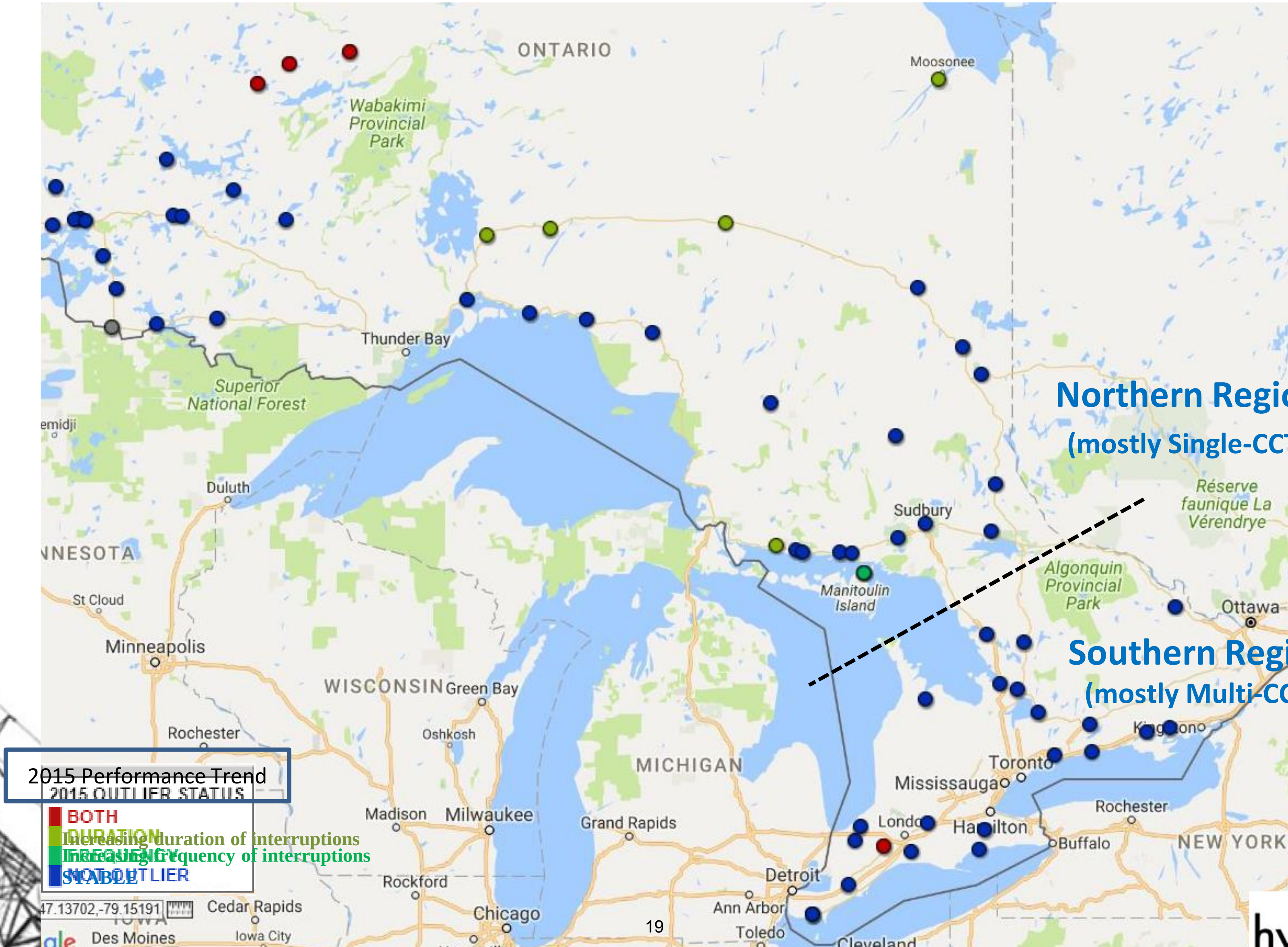
Tx System – Primary Causes of Interruptions:
(~67% occurs from Weather & Equipment Failures)

Power outage causes (2012-2016)

Equipment failure	**49%**	Majority of failures have occurred on Lines assets (Insulators, Wood Poles, Conductor, etc)
Weather	**18%**	Adverse weather (freezing rain, ice, lightning)
Environment	**15%**	Occasionally, Hydro One experiences tornados, forest fires, major environmental events
Animal/vehicle or Tree Contacts	**14%**	Animal contacts with Hydro One's equipment and off-corridor tree-felling events
Configuration	**2%**	Issues relating to the configuration of the system at the time of the event.
Unconfirmed causes	**1%**	Sometimes Hydro One crews can't determine the exact cause of an outage.

First Nations: Transmission Connections



Transmission Connections Performance: By Geographic Region (First Nations Only)

Transmission System - Northern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
[1]First Nations	44	216.4 (68.4)	4.48

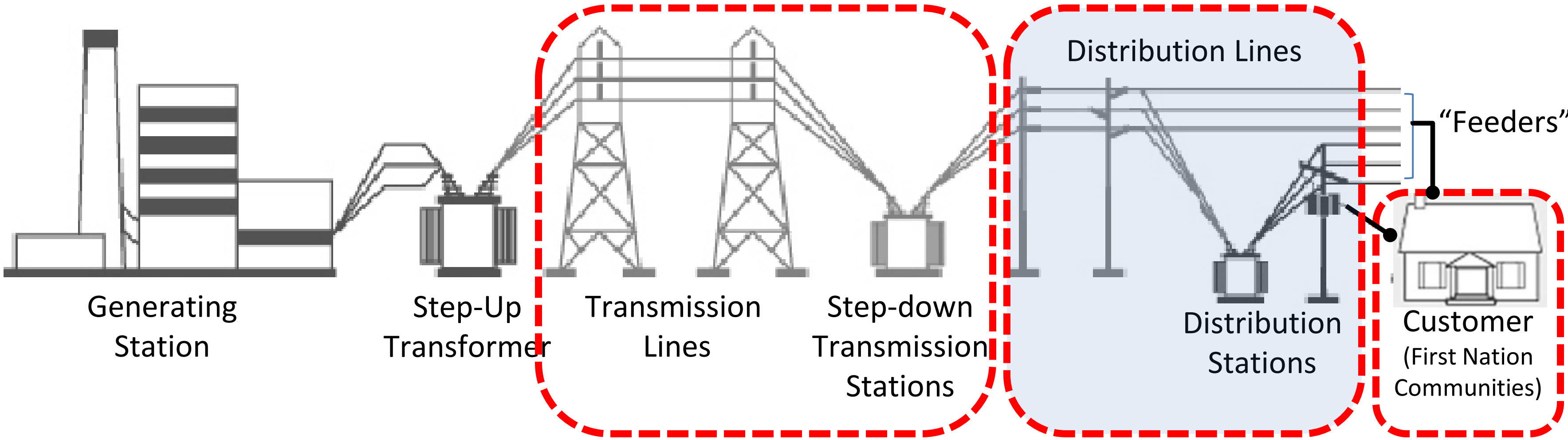
Transmission System - Southern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes /Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
First Nations	25	25.1	1.20

[1] *Two lines account for 58% of total interruption minutes for entire year*

How is Hydro One maintaining Reliability in the Transmission System?

- **Increasing Capital Investments (Lines)**
- **Leveraging Technology (Distance-to-Fault)**
- **Reducing Planned Outages (Bundling Work)**

Distribution System



1 **Transmission System:** ~490 Transmission Lines, ~340 Transmission Stations, 29,000 km of Transmission Lines

2 **Distribution System:** ~3200 Distribution Lines, ~1000 Distribution Stations, 130,000 km of Distribution Lines

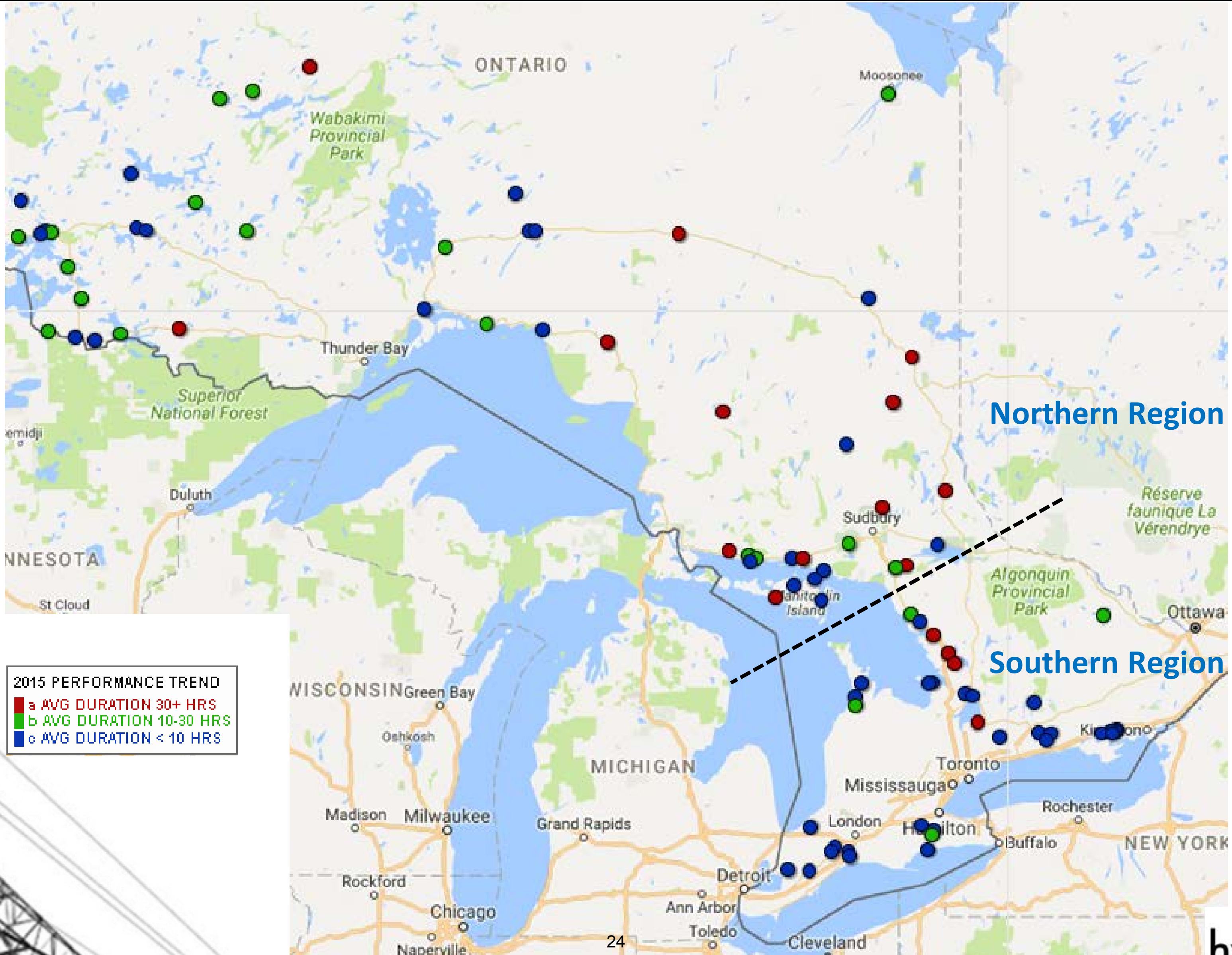
3 **First Nation Communities:** Supplied from 55 Transmission Lines and from 89 Distribution Lines

Dx System – Primary Causes of Interruptions:
(~50% occurs from Tree Contacts & Equipment Failures)

Power outage causes (2013-2015)

Tree damage	**24%**	Trees fall on lines during storms.
Equipment failure	**24%**	Poles, transformers, lines failures can cause an outage.
Unconfirmed causes	**19%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Scheduled outages	**16%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Transmission Outage	**12%**	Issues relating to the larger grid, like damage to transmission lines.
Animal or vehicle damage to equipment	**5%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.

First Nations: Distribution Connections



hydro one

Dx Performance: By Customer Segmentation (& First Nations Only)

Distribution System - Overall (2016 YE Performance)

Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	13.3	3.4
[1]First Nations	13.5	3.6

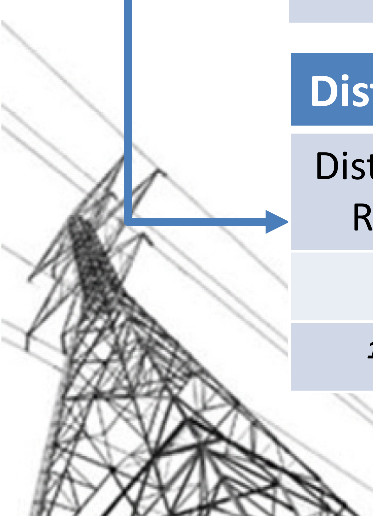
Note: *Includes Force Majeure and Loss of Supply (i.e. interruptions due to Transmission events)*

Distribution System - Rural (2016 YE Performance)

Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	14.6	3.7
[1]First Nations	13.5	3.6

Distribution System - Urban (2016 YE Performance)

Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	3.0	1.7
[1]First Nations	Mostly Rural	Mostly Rural



[1] First Nations results are for 2015 year. When available, 2016 numbers will be inserted. Only a small portion of First Nations are in an Urban area (<10% estimated)

How is Hydro One maintaining Reliability in the Distribution System?

Reducing the number of outages per year

Renewal program
Replace equipment that's affecting reliability

Tree trimming
Targeting tree trimming in areas with high tree contacts

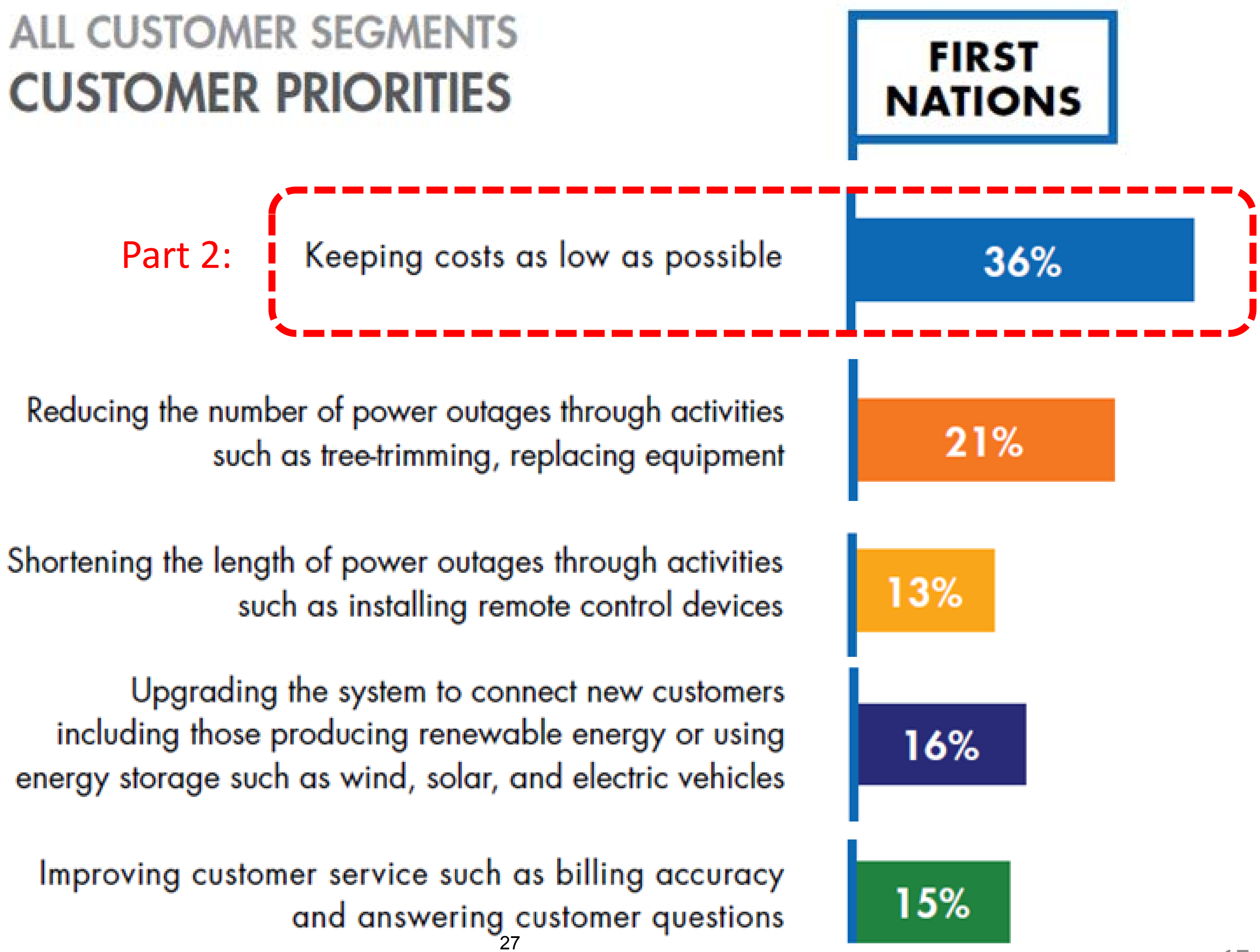
Smart Grid
Adding more protective devices & remote control to reduce chance of outages

Shortening the length of power outages

Improved Outage Response
Detects outages, limits size, dispatches repair crews

Monitoring and control
Use technology that lets Hydro One remotely respond to outages

Customer Engagement Results



Controlling Costs:

- **Pacing Expenditures**
- **Vegetation Management**
- **Move-to-Mobile**

Questions & Answers

HYDRO ONE'S DISTRIBUTION RATES APPLICATION (2018-2022)

Oded Hubert

Vice President – Regulatory Affairs

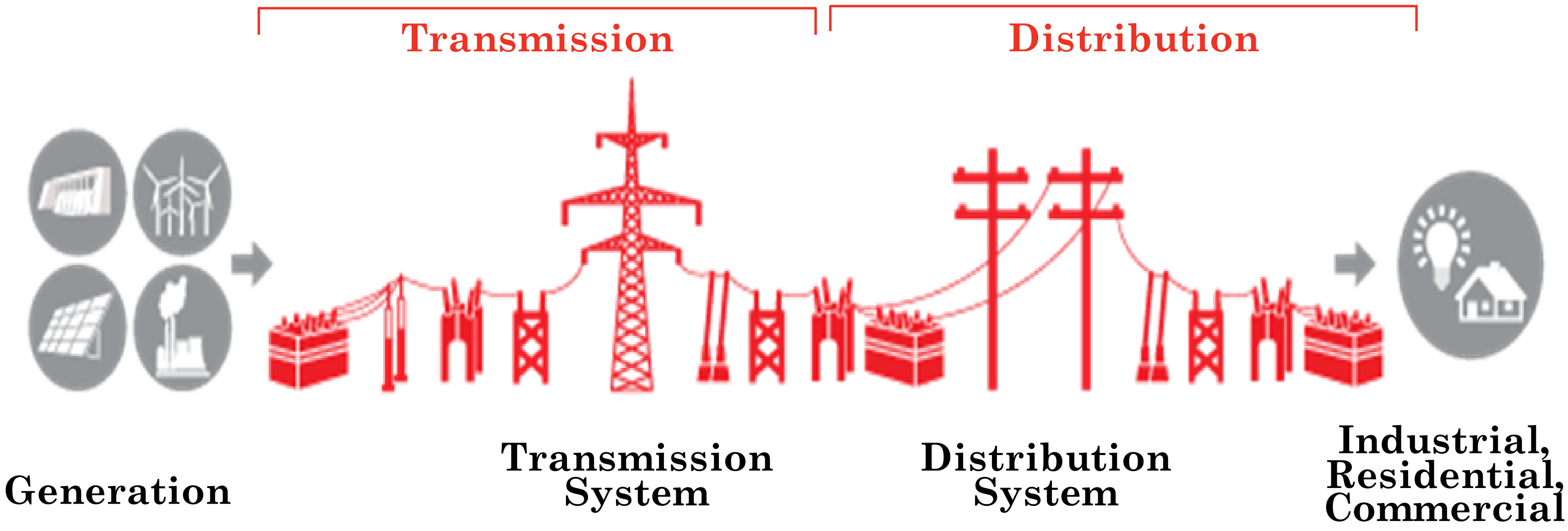
Hydro One and First Nations Engagement Session

February 9 and 10, 2017 30

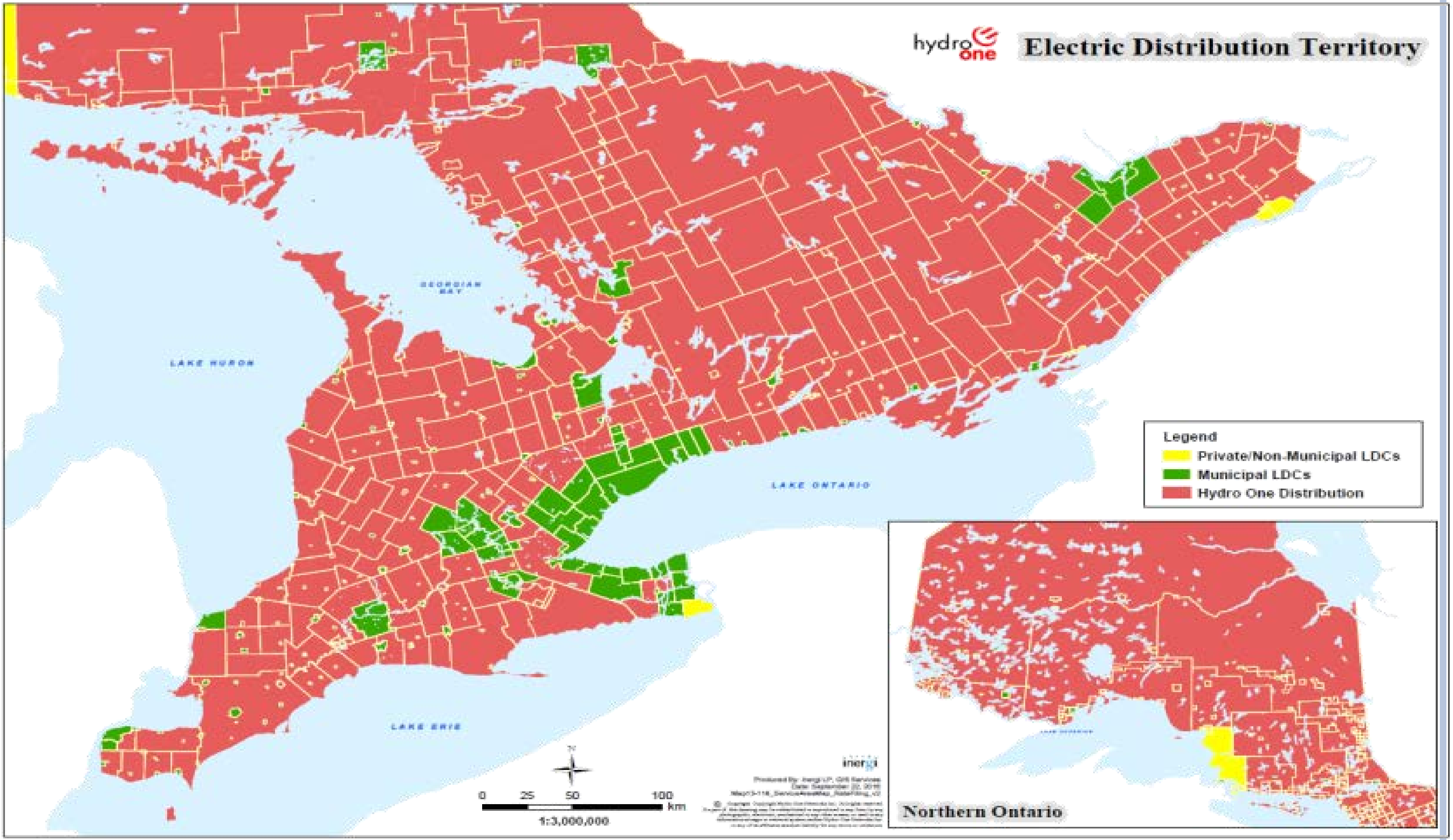
Hydro One Limited (Hydro One)

- Hydro One is Ontario's largest electricity delivery company
- We are owned 70% by the province of Ontario and 30% by public shareholders
- We have three businesses:
  - Transmission;
  - Distribution; and
  - Telecommunications

Hydro One's Role in the Ontario Electricity System



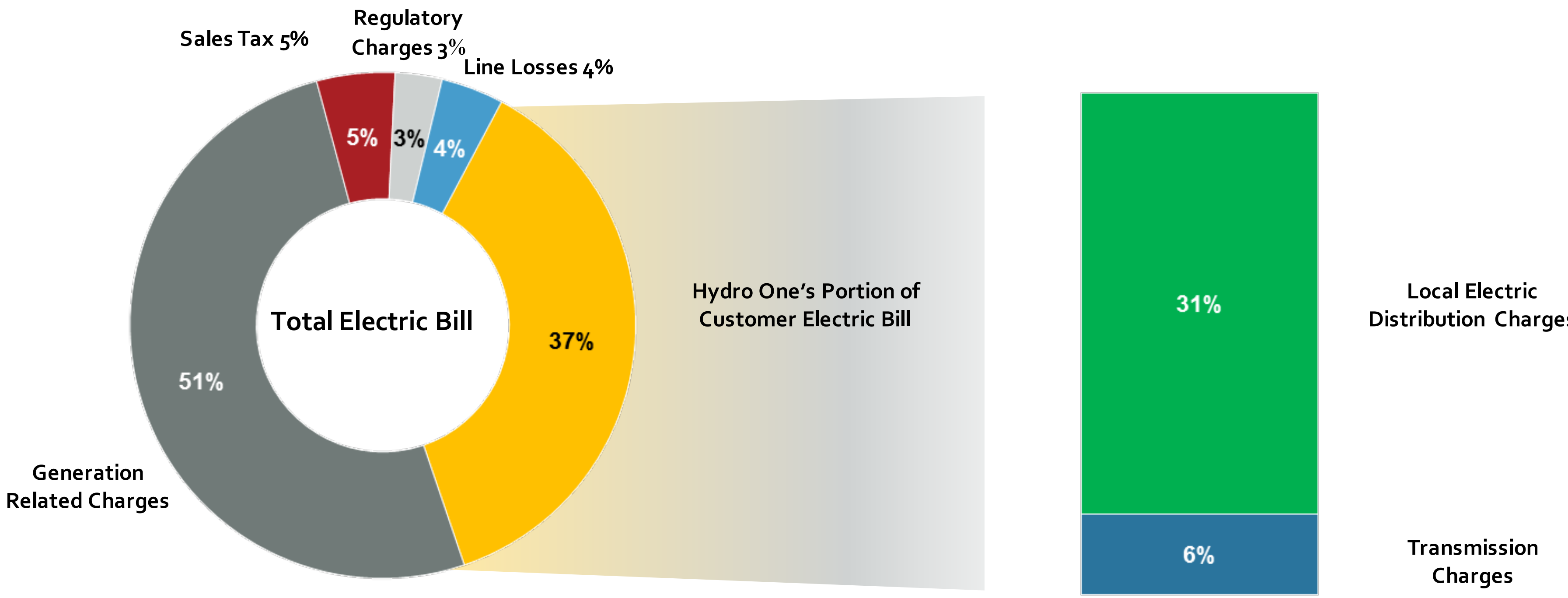
Distribution System Map



Distribution System Stats

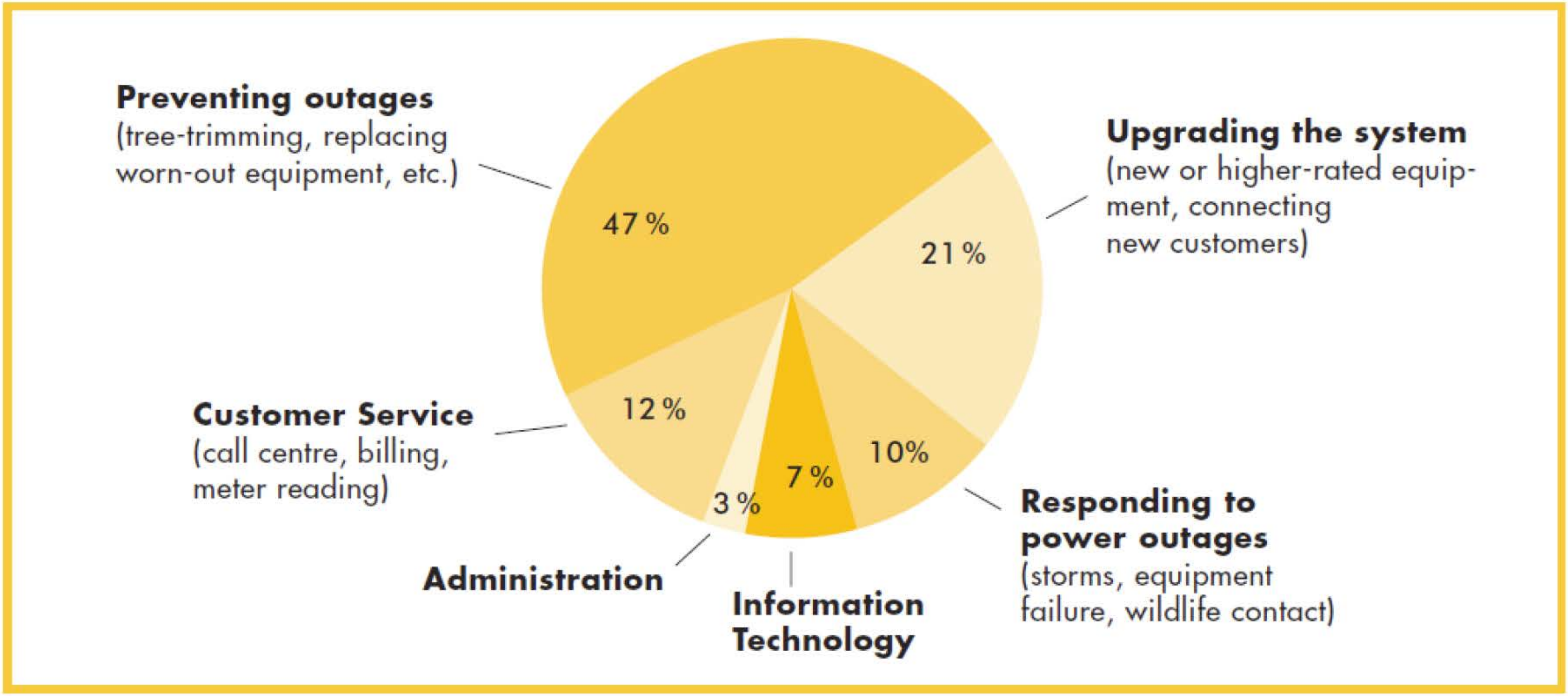
Service Territory	Rural Service Area - 960,123 sq. km Urban Service Area - 677 sq. km
Customers	1.3 million residential and business customers as well as 55 local distribution companies
Distributed Generation	Approximately 13,400 small, mid-size and large embedded generators connected to Hydro One's distribution network, including approximately 12,600 generators with capacities of up to 10 kW and 1,600 generators pending connection
Stations	Approximately 1,000 distribution and regulating stations
Circuit Length	123,000 kilometres of primary low voltage distribution lines

Breakdown of Electricity Costs to Customers



How Distribution Charges are Spent by Hydro One

- Hydro One receives a distribution charge which pays for a broad range of distribution system costs:



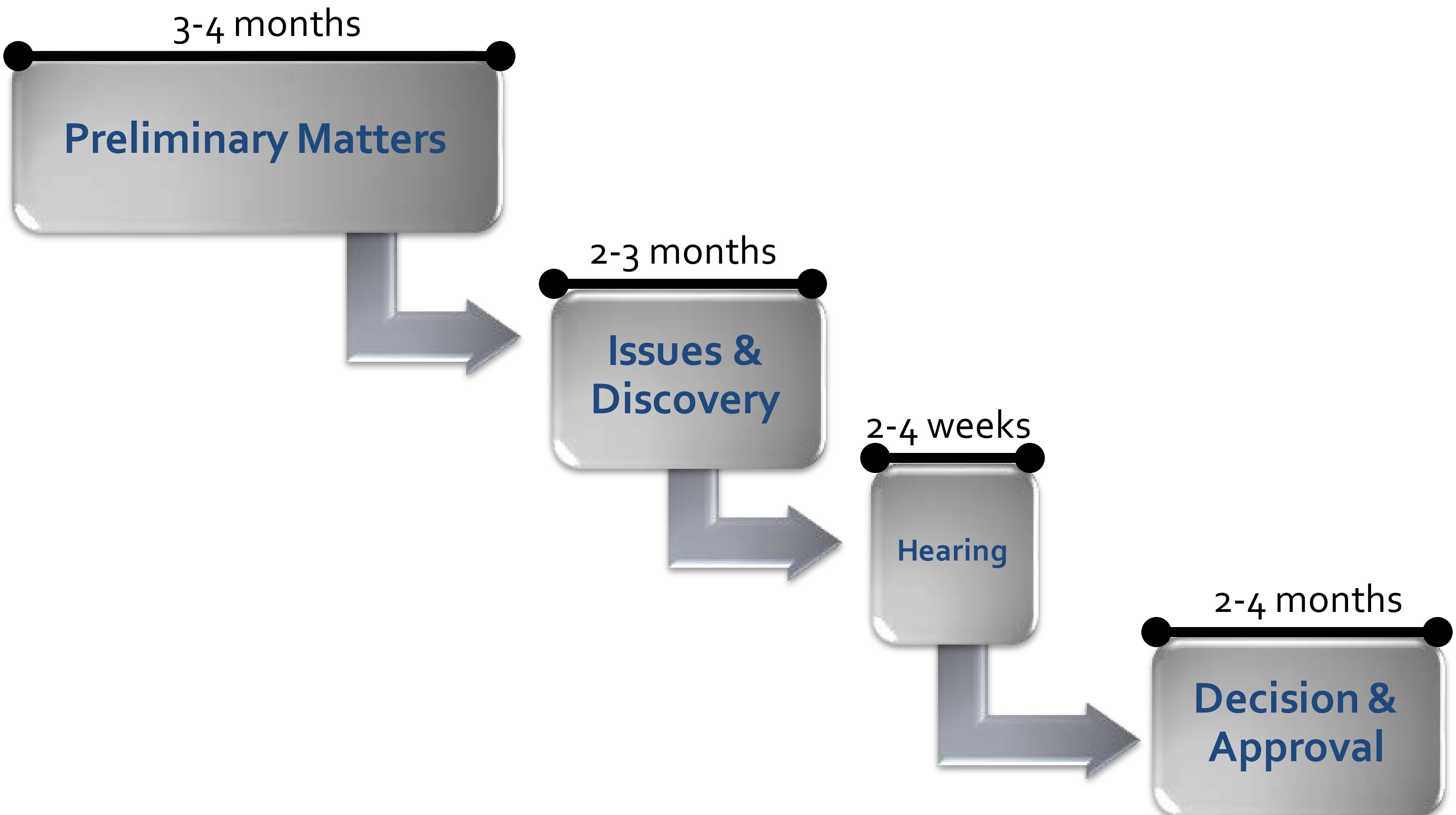
How Distribution Rates are Set

- Electricity distribution rates are set by the Ontario Energy Board (OEB), an independent public agency.
- The OEB sets rates following a public hearing based on evidence.
- Hydro One will be applying to the OEB to set our distribution rates for the period 2018-2022 in March 2017.

Objectives of the OEB

1. Protect the interests of consumers
2. Promote economic efficiency and cost effectiveness… maintain a financially viable electricity industry
3. Promote conservation & demand management
4. Facilitate the smart grid
5. Promote generation from renewable energy sources:
   - consistent with the policies of Government; and
   - expansion or reinforcement of transmission and distribution systems.

Stages of an Application



Usually takes 8 – 12 months

Balancing Key Considerations

Hydro One's Application

Our proposal is focused on addressing customer needs and preferences including:

- **Keeping Costs Low**

  Keep costs as low as possible is customers' top priority
- **Maintain Reliable Service**

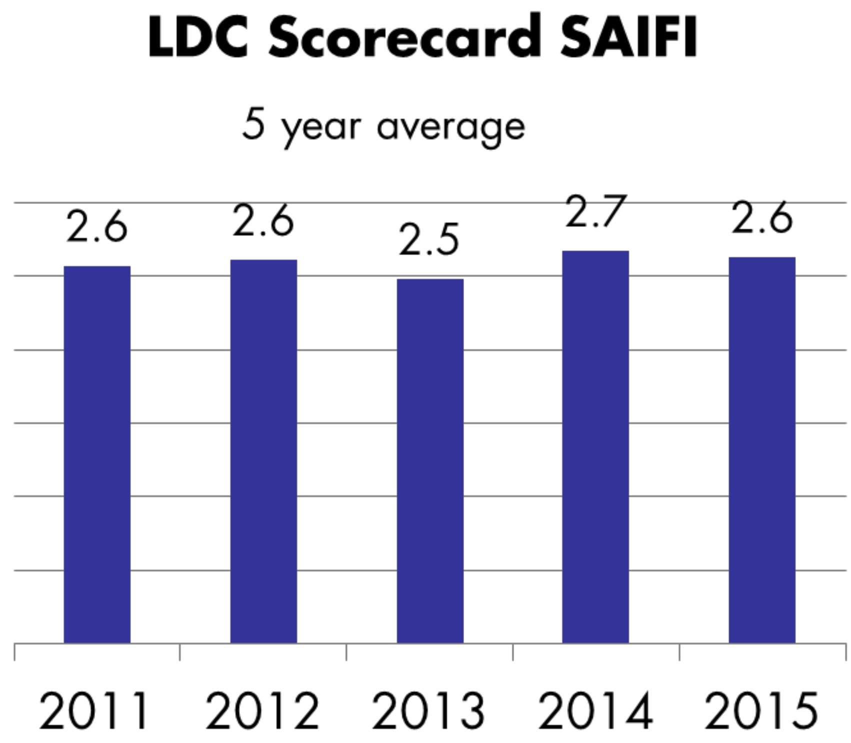
  Maintaining reliable electricity service is consistently second priority to cost
- **Large Customers**

  Large customers are more concerned with reliability and capacity
- **Manage Rate Impacts**

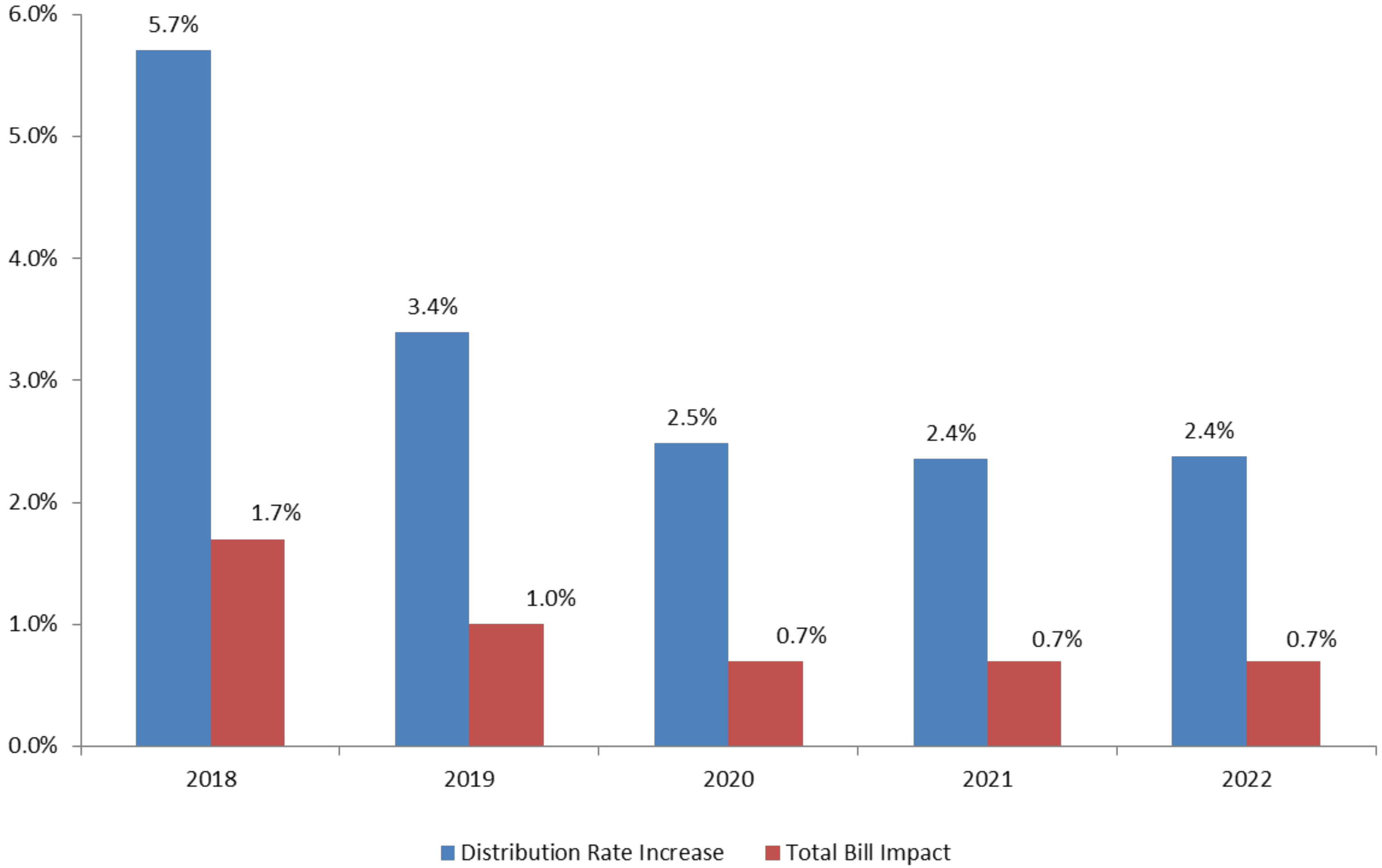
  Willingness to accept a rate increase to improve service level is limited

Service Enhancements Hydro One Will Deliver

Hydro One's overall business plan was optimized such that asset condition and reliability will not deteriorate



Proposed Distribution Rate Increases And Total Bill Impact



Main Areas of Hydro One Rate Increases

Cost Drivers	2018	2019	2020	2021	2022
Operations, Maintenance and Administration	-0.1%	0.5%	0.5%	1.2%	0.5%
Capital Related (e.g., poles, wires and transformers)	2.0%	2.9%	2.6%	3.3%	2.5%
Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Load Impact	2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Other Revenue and Rate Riders	1.1%	0.0%	0.0%	-0.1%	0.0%
Total	5.7%	3.4%	2.5%	2.4%	2.4%

Additional Cost from Declining Electricity Use (Load Impact)

- The cost of distribution services is spread out among all Hydro One customers based on total electricity consumption.
- Total electricity consumption has been decreasing since rates were last set, so the cost of serving each individual customer will increase by 2% in 2018.
- This is a one-time adjustment and will not lead to increases in 2019-2022.

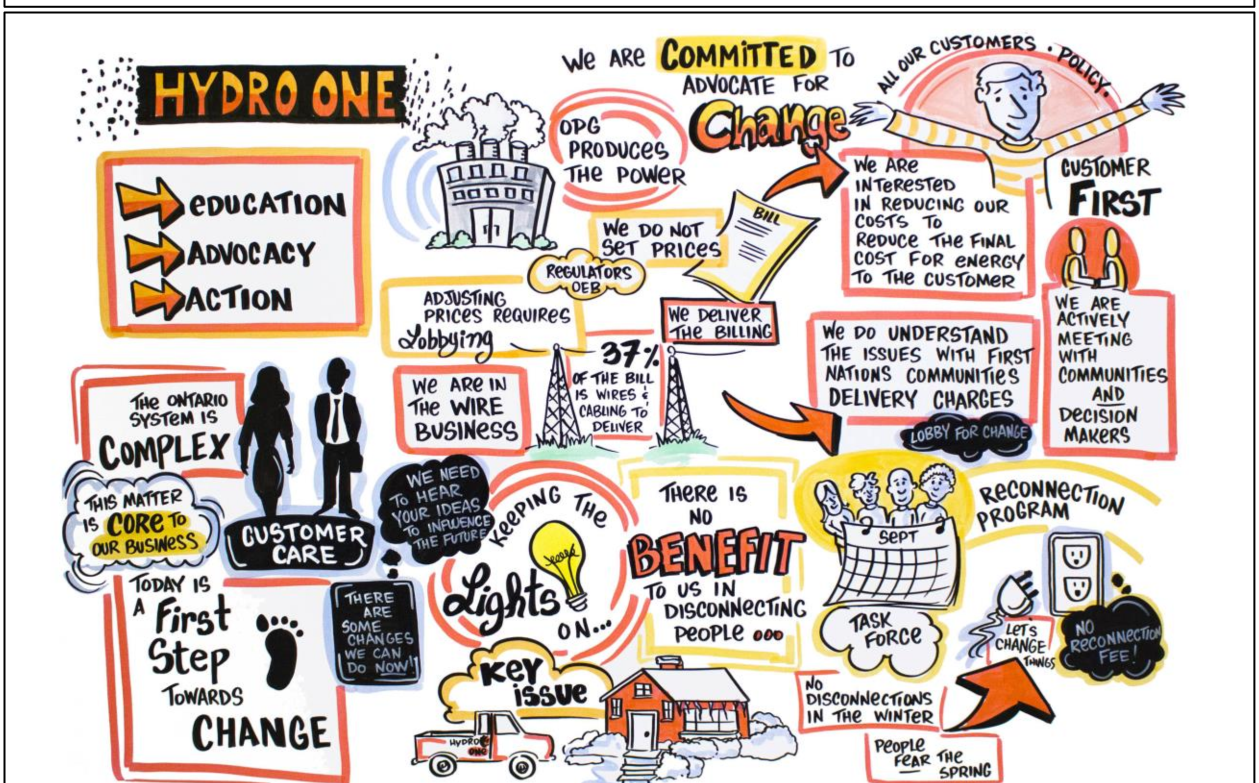
On-Reserve First Nations Electricity Customers

- Minister of Energy asked the OEB to examine and provide advice for an appropriate electricity rate or rate assistance program
- Hydro One has been supportive of this initiative and has provided input to the OEB
- January 1, 2017 OEB submitted its report to the Minister of Energy and now waiting for next steps to be announced.

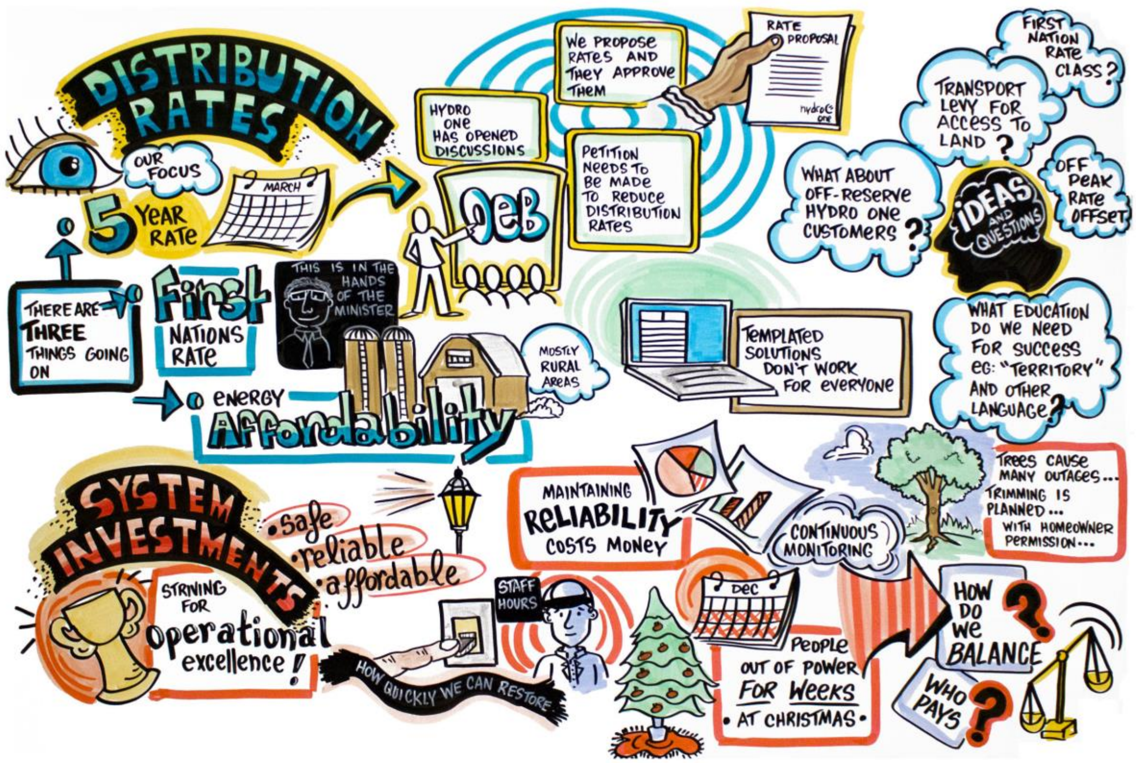
Questions & Answers

Thank you for attending!

HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10



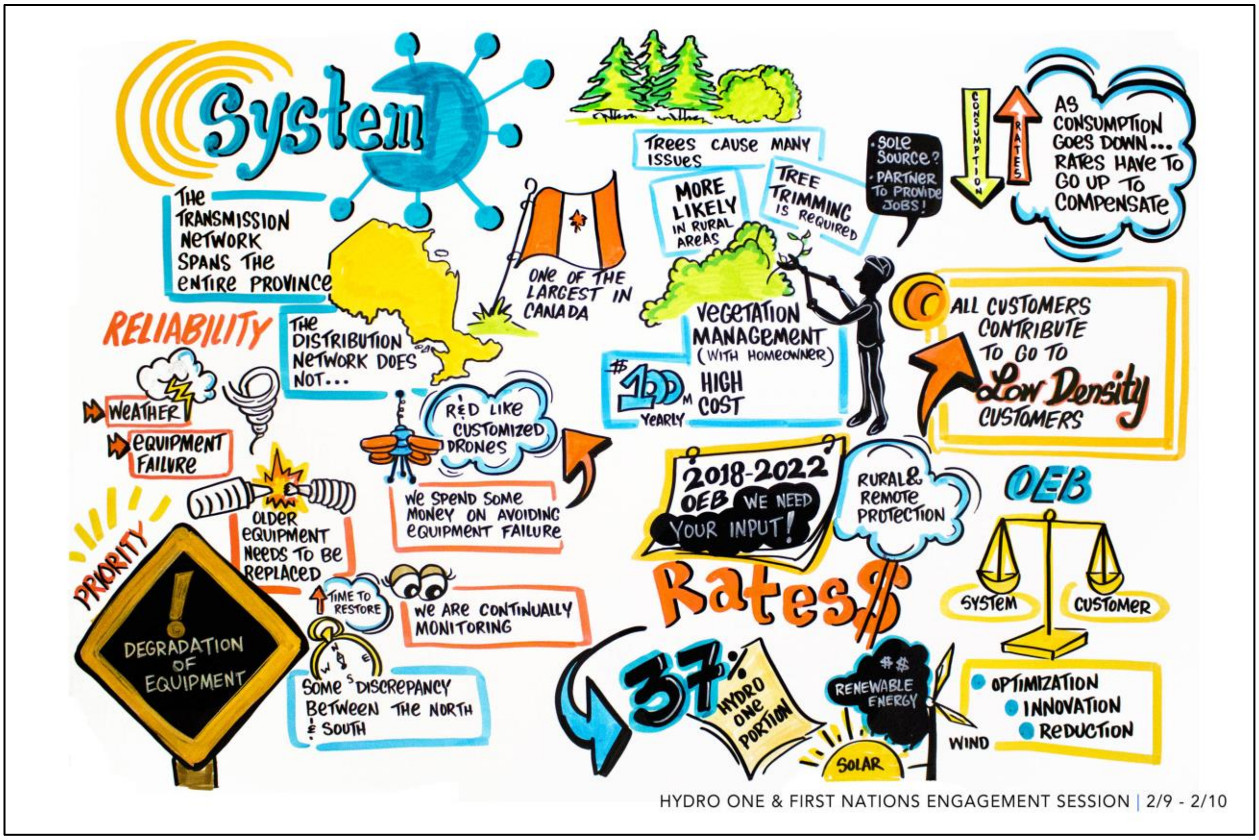
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10



HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10


SHARING WHAT YOUR COMMUNITY MEMBERS ARE SHARING WITH YOU
HYDRO ONE
FIRST NATIONS
RESPECT
CROSS CULTURAL EDUCATION
THE Leaders AND Decision Makers ARE IN THE ROOM
ENGAGEMENT SESSION NOT CONSULTATION
A BIG FIRST STEP
FIRST OF MANY!
TIME TO MOVE FORWARD
EACH COMMUNITY IS DIFFERENT
TURNING THE CORNER ON THE PAST • MUTUALLY AGREEABLE •
Relationships
Listen
RESPECT PROTOCOLS
TAKE Time
WHEN I SEE A TRUCK... I EXPECT IT'S DISCONNECTION
DISCONNECTION
hydro one
FEES COLLECTED DON'T COME TO US!
EDUCATION
ISSUES
OUR COMMUNITIES CAN'T AFFORD TO HEAT THEIR HOMES
POWER IS A NECESSITY!
OUR ELDERS NEED HELP
DELIVERY CHARGES
OUTWEIGHS CONSUMPTION!
BILL $$$
TAX EXEMPTION
HYDRO ELECTRIC DAMS
LINES UNDERWATER
POLES
ENVIRONMENTAL IMPACT
SPRAYING
THIS IS PRODUCED FROM OUR LAND...
NO ONE WANTS TO TAKE BLAME!
WITH ACCESS TO OUR LAND
PEOPLE SHOULDN'T HAVE TO RELY ON OTHERS TO PAY... LOSS OF PRIDE IS AN ISSUE
WE CAN'T JUSTIFY HIGH PROFITS WHEN PEOPLE ARE CHOOSING
FOOD OR POWER
But...
URBAN AREAS WITH HIGHER INCOMES PAY FAR LESS
Treaty
STILL WAITING FOR PROMISES TO BE FULFILLED!
1850...
HYDRO IS A RESOURCE FROM MOTHER EARTH
SEWAGE
POLLUTION
1951
A PROMISE WAS MADE TO PROVIDE POWER AT NO COST
UNDERSTANDING
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10


hydro one
GOING THROUGH MANY Changes
WE ARE IN THE WIRING BUSINESS
BILL
WE PLAY A PART IN NEGOTIATING DELIVERY CHARGES
ADVOCACY
IT'S TIME FOR CHANGE!
TOGETHER WE CAN INFLUENCE
FIX THE SYSTEM
IT'S A CRISIS
DISTRIBUTION RATE FILING
NO FEE
WORKING WITH INDIVIDUALS TO HELP THEM
FIRST NATIONS RATE
50% GENERATION COST
BILL
CALL TO ACTION
LOWER COST
ACTION
TREATY RIGHTS
RECONNECTION PROGRAM
PAYMENT PLANS
I WANT TO PAY... I CAN'T!
EDUCATION
HOW THE SYSTEM WORKS
Become more efficient
WATCH OUR COSTS
PRESENTING TO POLICY MAKERS ON AFFORDABILITY
WE HAVE MADE OVER 200 COMMUNITY VISITS TO DATE
1/3 (AVERAGE) DISTRIBUTION BUT BASED ON DENSITY
COST RECOVERY SYSTEM
COST IS LOWER WHERE MORE SHARE THE BURDEN
RURAL
New PROGRAMS
ADDRESS ISSUES
RIGHTS HOLDERS
You Are
PARTNERS
EMPLOYEES
MET WITH 600 CUSTOMERS TO DATE
ASKING FOR CHANGE
HIGH CONSUMPTION + HIGH DELIVERY + POVERTY = CRISIS
ELECTRIC HEAT MOSTLY
INSULATION ISSUES
ANALYSIS
MEETINGS
RATE FILING
EDUCATION
2 WAY
GLOBAL ADJUSTMENT
BILL
CONSUMPTION HIGH DELIVERY HIGH
POS EXEMPTION (OFF AND ON RESERVE)
DISTRIBUTION CHARGE
TRANSMISSION LINES ON OUR LAND
SHOULD BE BRINGING IN REVENUE BUT ISN'T...
WE NEED TO WORK TOGETHER TO RESOLVE WITH DECISION MAKERS
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10


System
The transmission network spans the entire province
The distribution network does not...
One of the largest in Canada
Trees cause many issues
More likely in rural areas
Tree trimming is required
Sole source? Partner to provide jobs!
Consumption
Rates
As consumption goes down... rates have to go up to compensate
Reliability
Weather
Equipment failure
Older equipment needs to be replaced
Priority
Degradation of equipment
R&D like customized drones
We spend some money on avoiding equipment failure
Time to restore
We are continually monitoring
Some discrepancy between the north & south
Vegetation management (with homeowner)
$100M yearly
High cost
All customers contribute to go to low density customers
2018-2022 OEB We need your input!
Rural & remote protection
OEB
System
Customer
Rates
37% Hydro One portion
Renewable energy
Solar
Wind
Optimization
Innovation
Reduction
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10

Aboriginal Procurement: Doing Business with Hydro One

2017 Métis Nation of Ontario Engagement Session

Aboriginal Procurement Procedure

- Procedure supports the First Nations & Métis Relations policy through procurement opportunities for qualified Aboriginal businesses
- Goals:
  - Promote business and workforce development for Aboriginal Businesses
  - Diversify supplier base
  - Increase access to Procurement opportunities for Aboriginal Businesses

Aboriginal Procurement Procedure

- There are 3 approaches to provide opportunities to Aboriginal businesses:

  1. Aboriginal Participation is preferred
  2. Competition is limited to qualified Aboriginal businesses
  3. Direct Award to qualified Aboriginal businesses

Procurement at Hydro One

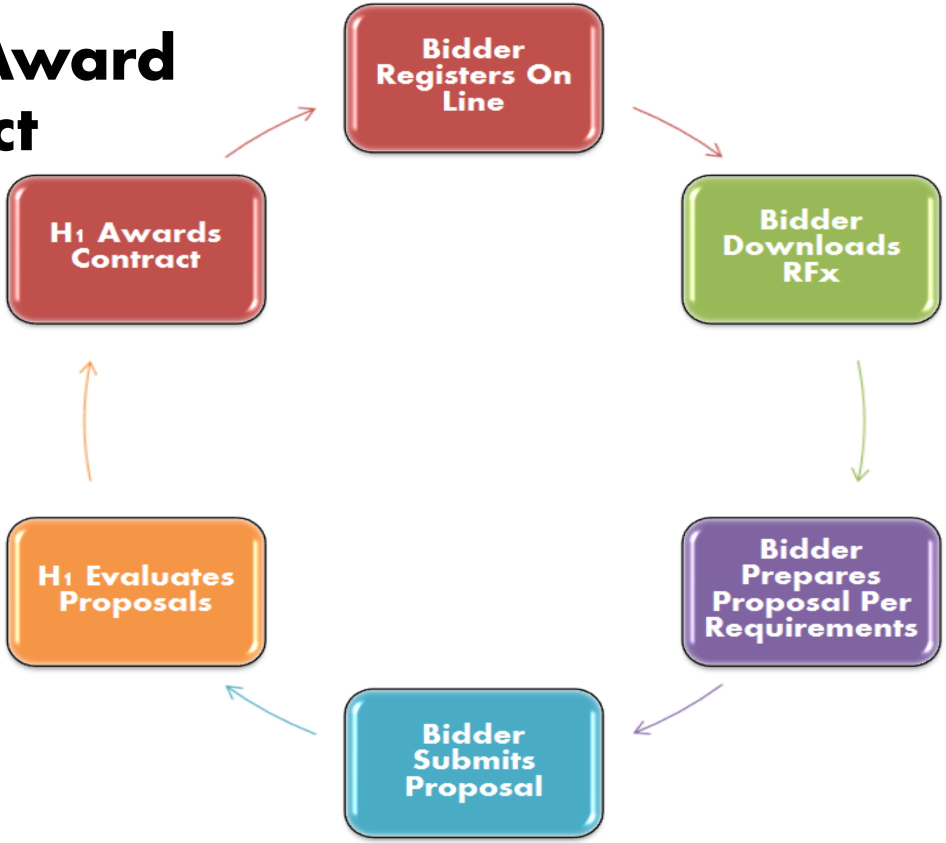
hydro one

Types of materials and services purchased

- Heavy duty equipment (floats, trucks, backhoes, cranes, etc.)
- Road construction services
- Aggregate and concrete
- Fencing
- Forestry/vegetation management services
- Pole digging and rock drilling services

Procurement at Hydro One

6 Steps to Award Contract



BID System - Key Concepts

- Bidders can retrieve all RFx types from the BID System
- Only RFQs are submitted in the BID System
- All other RFx (RFP, RFPQ, RFI) will be submitted as directed in the individual RFx

BID System - Online Registration

- To register for the BID System, go to

  http://www.HydroOne.com/doingbusiness

- Select **Bidder Registration**
- Complete all required fields (*) such as company name, email address, etc.
- During registration, the option to self-identify as an Aboriginal Business is available

BID System - Reference and Contact Information

- A complete guide on using the Bid System entitled **How to Instructions** can be found on the Doing Business with Hydro One webpage:

  http://www.HydroOne.com/doingbusiness

- For inquiries related to registration or access to the Bid System, please contact:

  BidderRegistrationHelp@HydroOne.com

- For all other general inquiries, please contact:

  NewVendorInquiries@HydroOne.com

Bidding Documents – Process & Qualifications

- RFP Process Requirements
  - RFP schedule and submission process
  - Evaluation considerations
  - Key commercial terms
- Qualifications
  - Labour Requirements as applicable
  - Insurance Requirements/WSIB
  - Health and Safety

Aboriginal Participation

- RFQs include Aboriginal business declaration
- All RFPs include Aboriginal Participation
  - Evaluation Criteria are:
    - Ownership of bidder or partners
    - Subcontractors
    - Aboriginal community/personnel involvement in the delivery of the materials/services
      - Focus on local Aboriginal persons and businesses
    - Active diversity programs and policies

Aboriginal Participation - Self-Identifying

- Hydro One considers an Aboriginal business:
  - One which is at least 51% owned and controlled by an Aboriginal business(es) or person(s) and
  - If the firm has six or more full-time staff, at least 33% of the employees are of Aboriginal descent
- Joint Ventures or Partnerships:
  - Must be at least 51% owned and controlled by an Aboriginal business(es) or person(s)
  - 33% of the value of the work must be performed by an Aboriginal business (e.g. partner, subcontractor)

Aboriginal Participation - Self-Identifying

- Addition to Hydro One's Aboriginal Business Directory must be requested. Email:

  NewVendorInquiries@HydroOne.com

- A **Consent to Disclose Contact Information** form must be completed and returned to Hydro One for verification.
- Suppliers can search for Aboriginal businesses for sub-contracting or to partner

Opportunities – Upcoming RFPs

- Construction Materials – Aggregate & Concrete
- Office Trailers – RFP scheduled for 2018
- Printing Services – June/July
- Uniform and Laundry Services
- Pest Control
- Health Assessments
- Meter Replacements
- Directional Road Boring
- Rebar – 2Q 2017

Resources

- www.HydroOne.com/DoingBusiness
- New Vendor Inquiries: NewVendorInquiries@HydroOne.com
- BID System Help Desk: BidderRegistrationHelp@HydroOne.com
- www.HydroOne.com/FirstNationsMetis
- eInvoicing: http://supplier.taulia.com/customers/hydroone/

Questions

Customer Service

Imran Merali

Director Customer Program Delivery

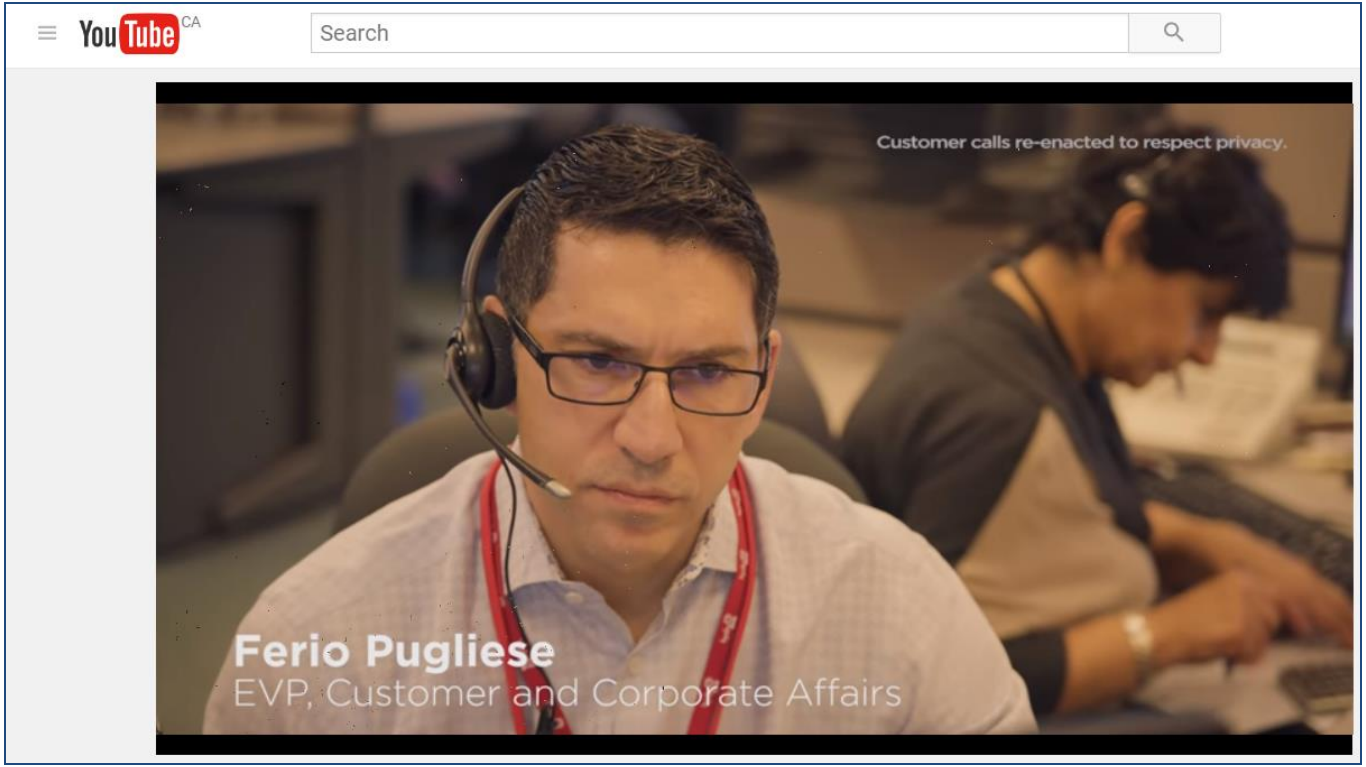
Métis Engagement Session

May 13, 2017

Flip the Switch

- **Flip the Switch** is our new commitment to customers to better listen and respond to their questions and concerns.

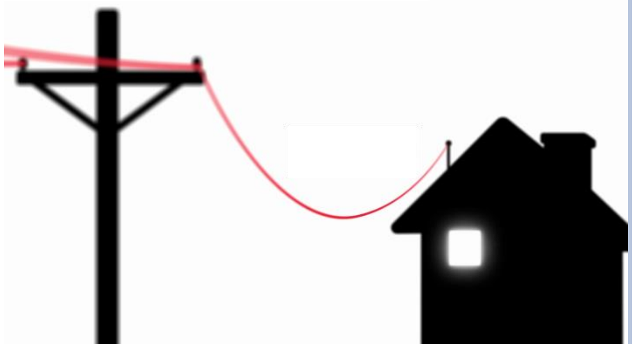
Flip the Switch Video



http://driftheswitch.hydroone.com/hydrooneday

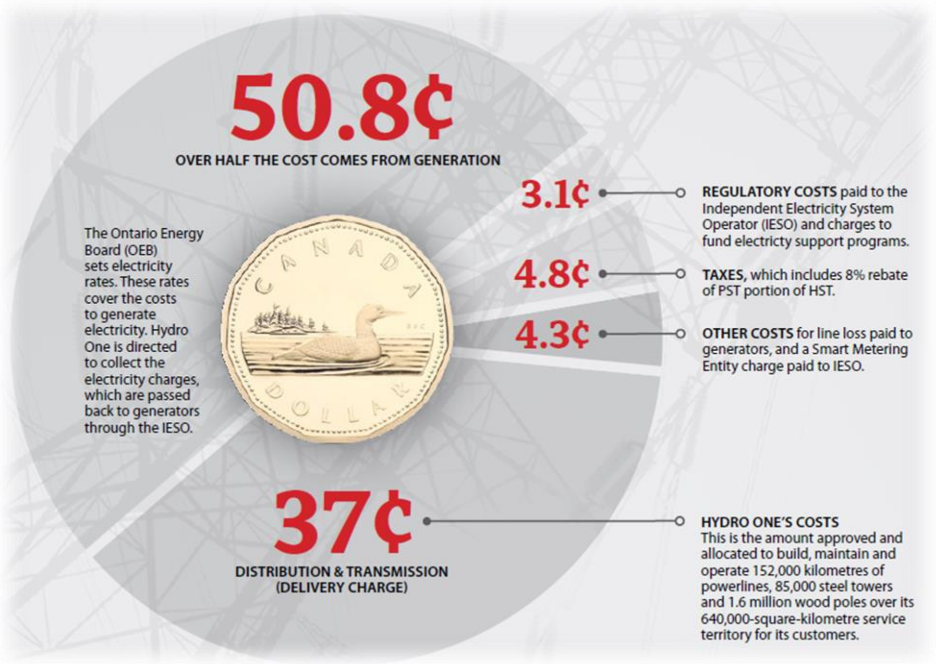
Customer Service Vision

- We are easy to do business with
- We are there when customers need us
- We are always connected



We Are Easy To Do Business With

- Education
- Advocacy
- Responsiveness



Fair Hydro Plan

- On March 2, the government announced changes that will provide significant electricity bill relief. As a result, Hydro One customers will start to see lower monthly bills as early as this summer. We advocated for these changes because we heard your concerns. That's the new Hydro One.

- The Province has introduced plans to bring relief and fairness to electricity bills by:
  - Reducing the Global Adjustment charge
  - Lowering the Delivery charge for residential customers with a low or medium density service type
  - Eliminating the Delivery charge for customers living on a reserve
  - Introducing an Affordability Fund to help those customers in need
  - Enhancing the Ontario Electricity Support Program

Fair Hydro Plan CON'T

- Customers will start to feel the relief as early as this summer.
- The average Hydro One customer will start to see their monthly bills drop by an average of 33 per cent.

Average Residential Medium Density (1,000 kWh per month)

	2017 Charges		
	Charges before Fair Hydro Plan	New charges with Fair Hydro Plan	Savings
Electricity	$111.39	$80.54	$30.85
Delivery	$78.59	$57.47	$21.12
Regulatory Charges	$7.57	$4.55	$3.02
Taxes	$25.68	$7.13	$18.55
Total Monthly Savings			$73.54 (33%)

Average Residential Low Density with electric heat (2,400 kWh per month)

	2017 Charges		
	Charges before Fair Hydro Plan	New charges with Fair Hydro Plan	Savings
Electricity	$267.34	$193.30	$74.04
Delivery	$167.92	$88.56	$79.36
Regulatory Charges	$18.28	$10.86	$7.42
Taxes	$58.96	$14.64	$44.32
Total Monthly Savings			$205.14 (40%)

Customer Relief Program

- Effective April 25th, Hydro One is providing additional relief to assist customers that accumulated significant balances on their accounts over the winter .
- These measures aim to help customers better manage their electricity usage to get back on track and avoid future disruption to their electricity service.
- The policy changes include:
  - Eliminating Residential Security Deposits
  - Reducing Deposit Requirements for Businesses
  - New Customer Relief Measures
  - Additional Low Income Funding
  - Extending our Winter Moratorium until June 1, 2017

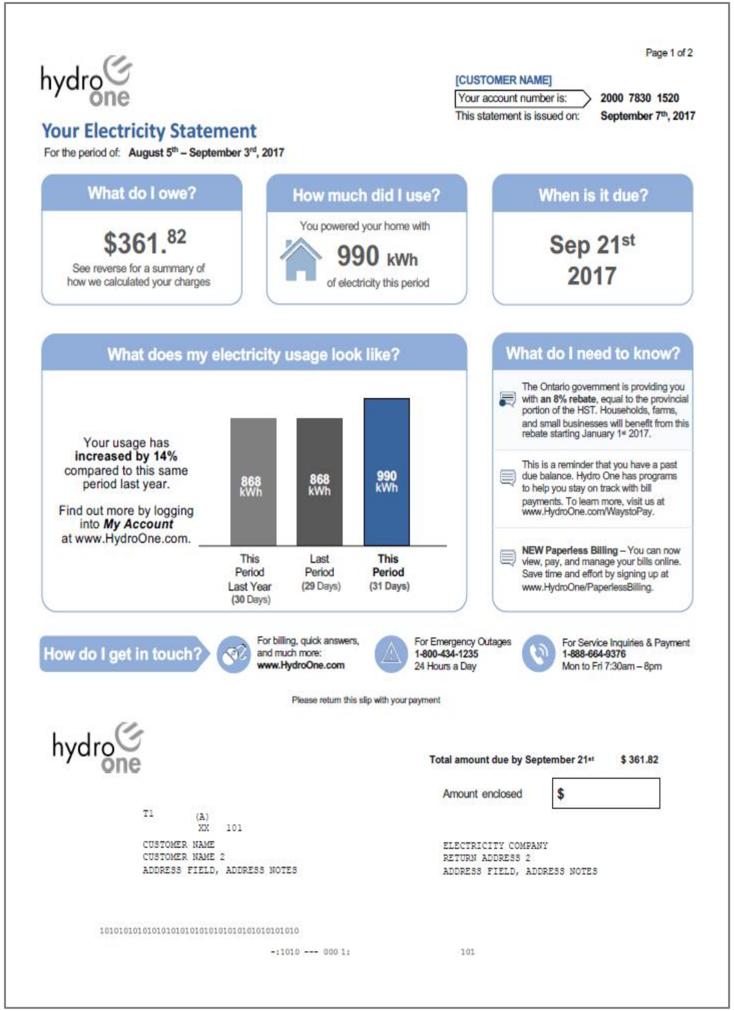
If We Miss Our Appointment With You, We Will Credit Your Account $75

If We Don't Connect Your New Service Within 5 Business Days of All Connection Requirements Being Met, We Will Credit Your Account $75.

If We Don't Return Your Phone Call Within 1 Business Day, We Will Credit Your Account $75

Billing

- Billing Accuracy continues to surpass Ontario Energy Board requirements and is the **highest in company history** at 99%.
- Hydro One is also introducing a newly designed bill in the fourth quarter of 2017 (pictured).


Page 1 of 2

[CUSTOMER NAME]
Your account number is: 2000 7830 1520
This statement is issued on: September 7th, 2017

Your Electricity Statement
For the period of: August 5th – September 3rd, 2017

What do I owe?
$361.82
See reverse for a summary of how we calculated your charges

How much did I use?
You powered your home with 990 kWh of electricity this period

When is it due?
Sep 21st 2017

What does my electricity usage look like?
Your usage has **increased by 14%** compared to this same period last year.
Find out more by logging into ***My Account*** at www.HydroOne.com.

What do I need to know?
The Ontario government is providing you with an 8% rebate, equal to the provincial portion of the HST. Households, farms, and small businesses will benefit from this rebate starting January 1st 2017.
This is a reminder that you have a past due balance. Hydro One has programs to help you stay on track with bill payments. To learn more, visit us at www.HydroOne.com/WaystoPay.
NEW Paperless Billing – You can now view, pay, and manage your bills online. Save time and effort by signing up at www.HydroOne/PaperlessBilling.

How do I get in touch?
For billing, quick answers, and much more: www.HydroOne.com
For Emergency Outages 1-800-434-1235 24 Hours a Day
For Service Inquiries & Payment 1-888-664-9376 Mon to Fri 7:30am – 8pm

Please return this slip with your payment

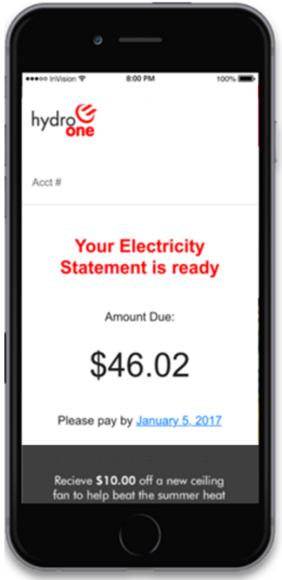
Total amount due by September 21st $ 361.82
Amount enclosed $

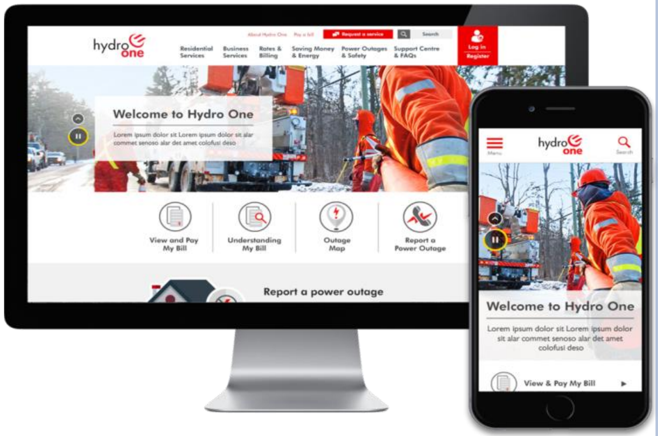
T1 (A) XX 101
CUSTOMER NAME
CUSTOMER NAME 2
ADDRESS FIELD, ADDRESS NOTES

ELECTRICITY COMPANY
RETURN ADDRESS 2
ADDRESS FIELD, ADDRESS NOTES

We Are Always Connected

- eBill Notifications & High Usage Alerts
- New Website
- Redesigned Bill





Employment and Training

hydro one

Overview

- Objective
- Our Commitment
- Apprenticeships
- Co-ops and Internships
- New Grad Program
- Summer Student Outreach Program
- Scholarships
- Reminders and Contact Information

Objective

Hydro One will strive to become a workplace of choice for First Nations and Métis people in Ontario, through active recruitment, retention, and promotion

Our Commitment

Commit resources for recruiting, retaining and developing Aboriginal talent to achieve equitable representation of Aboriginal persons in the workplace including supporting cross cultural awareness/sensitivity training.

Apprenticeships

- Hydro One typically hires four trades:
  - Powerline Technician
  - Utility Arborist/Forester
  - Construction & Maintenance Electrician
  - Coach & Truck Technician
- Detailed information can be found at: www.HydroOne.com/Careers and www.TradeUp.ca
- Hiring for each apprenticeship normally occurs in the fall

Powerline Technician (Lines)

Working Conditions

- Outdoors
- All weather conditions
- Physically Demanding
- Confined spaces
- Different locations throughout Ontario
- 5 days @ 8 hours or 4 days @ 10 hours

Apprenticeship Process:

- Hydro One has an apprenticeship program which is jointly offered through Hydro One and the PWU.
- Applications are accepted through the www.PWU.ca website and Aboriginal.Recruitment@HydroOne.com
- Include resume and cover letter
- Interview

Co-ops and Internships

- College or University Students
  - Must be enrolled in an eligible co-op or internship program
- Co-op: 4 to 8 month work terms
- Internship: 8 to 12 month work terms
- Positions posted every 4 months (winter, summer, fall)
- Positions offered across Ontario
- Students selected via interview
- Lunch and Learns/ Tours

New Grad Training Program

- Two year training program for university graduates from engineering and business programs
- Rotations to different departments and business units in the company across Ontario
- Continuous learning and opportunities to upgrade your skills over two years
- Positions are posted each September
- Lunch and Learns/Tours/Training

Summer Student Outreach Program

- Requirements:
  - Must be of First Nation, Métis or Inuit ancestry
  - Attending a post-secondary institution and scheduled to return
- General Clerical or Labourer positions offered across Ontario
- Positions posted in February
- 4-month summer term (May-August), two term maximum

Scholarships

- Leonard S. (Tony) Mandamin scholarship annual award
  - Awarded to students enrolled in electricity industry related programs at a recognized Ontario college or university
- Includes both a financial award and developmental work term

- **Deadline: October 1st**

- Guidelines and application available at: www.HydroOne.com/OurCommitment/AwardsScholarships

Want to Know More?

- Careers Website:

  http://www.HydroOne.com/Careers

- Questions related to employment:

  Aboriginal.Recruitment@HydroOne.com

- Hydro One First Nations and Métis Relations:

  http://www.HydroOne.com/FirstNationsMetis

Thank You

Hydro One Distribution Rates Application (2018-2022)

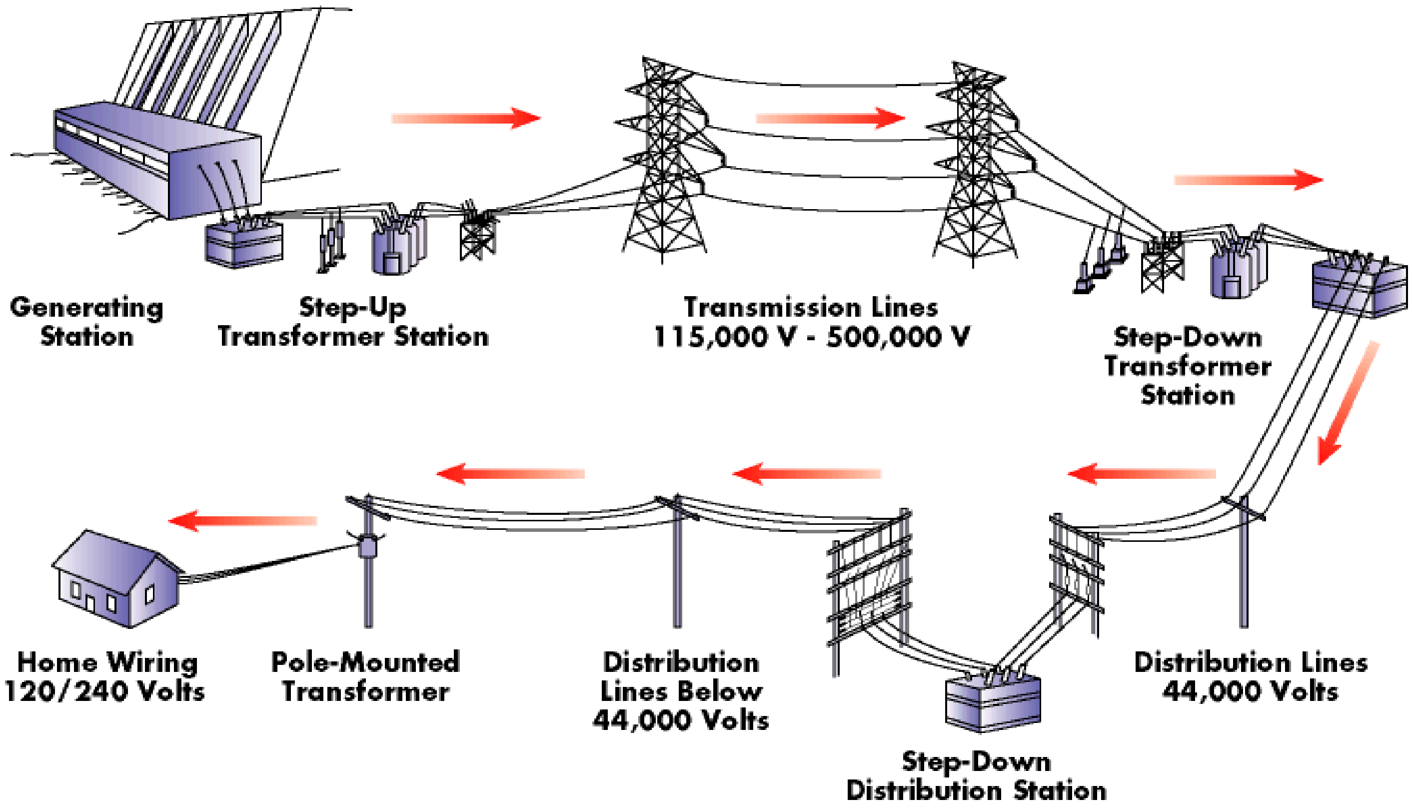
Oded Hubert

Regulatory Affairs

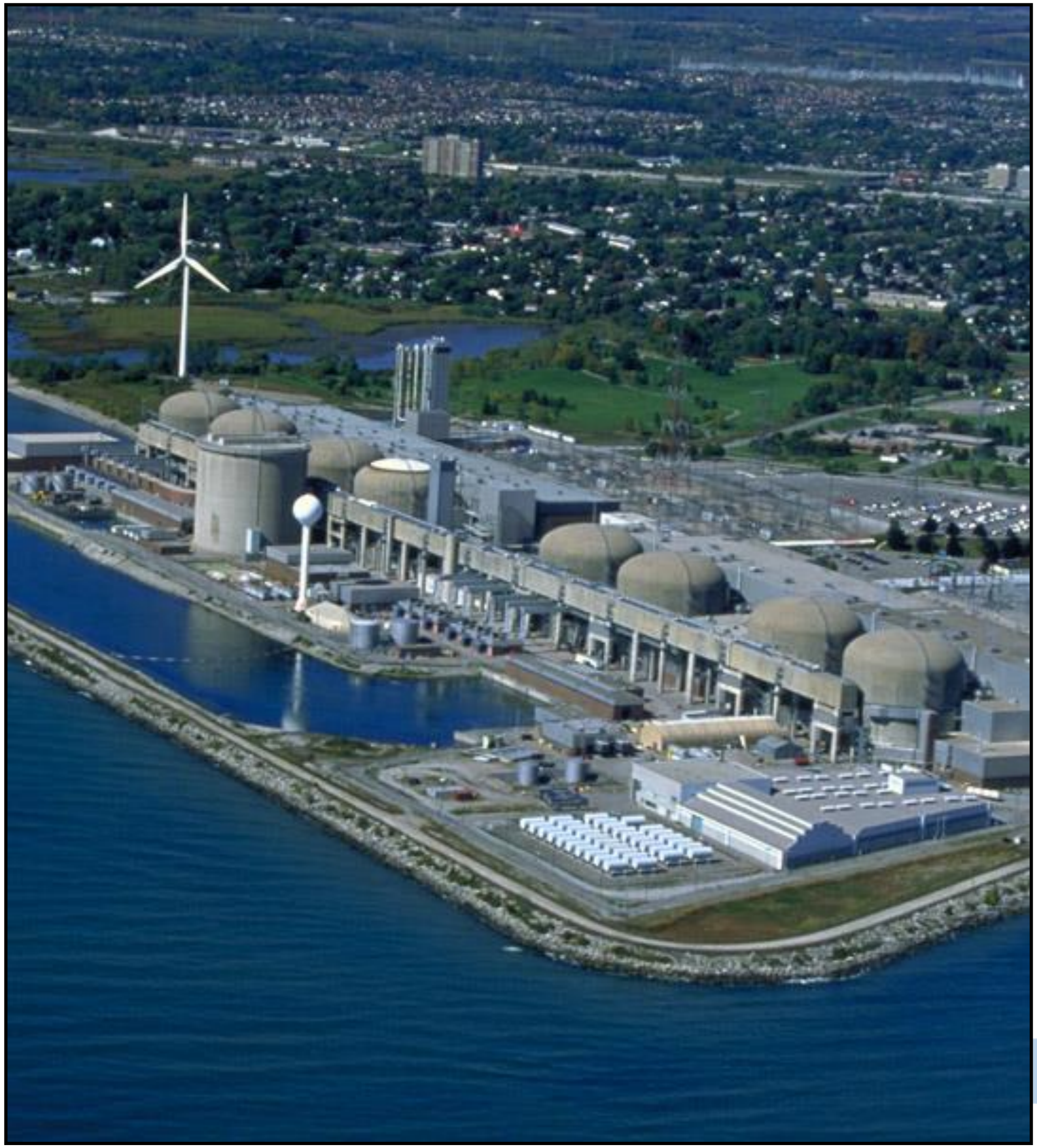
May 13th, 2017

Overview of Ontario's Electricity System

- Typical components and electricity flow from generator to customer.



Generators in Ontario's Electricity System



Bruce Power

Algonquin Power

TransAlta

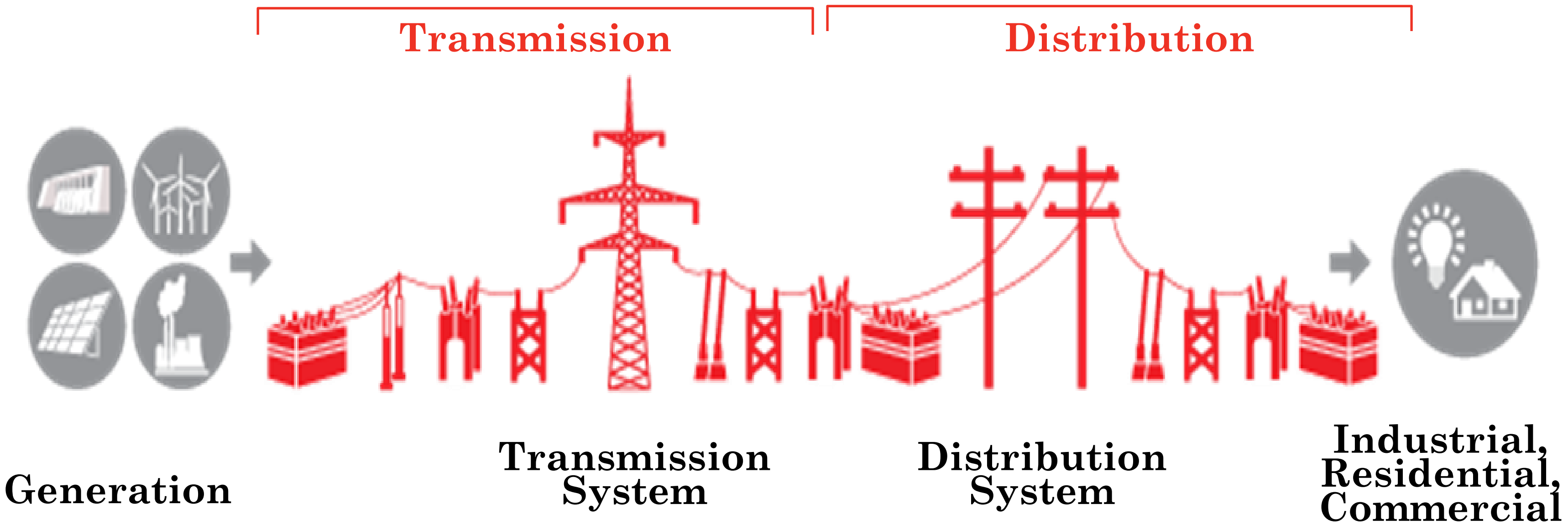
Brookfield

SITHE GLOBAL

ONTARIO POWER GENERATION

AIMPOWERGEN
PART OF THE REG GROUP

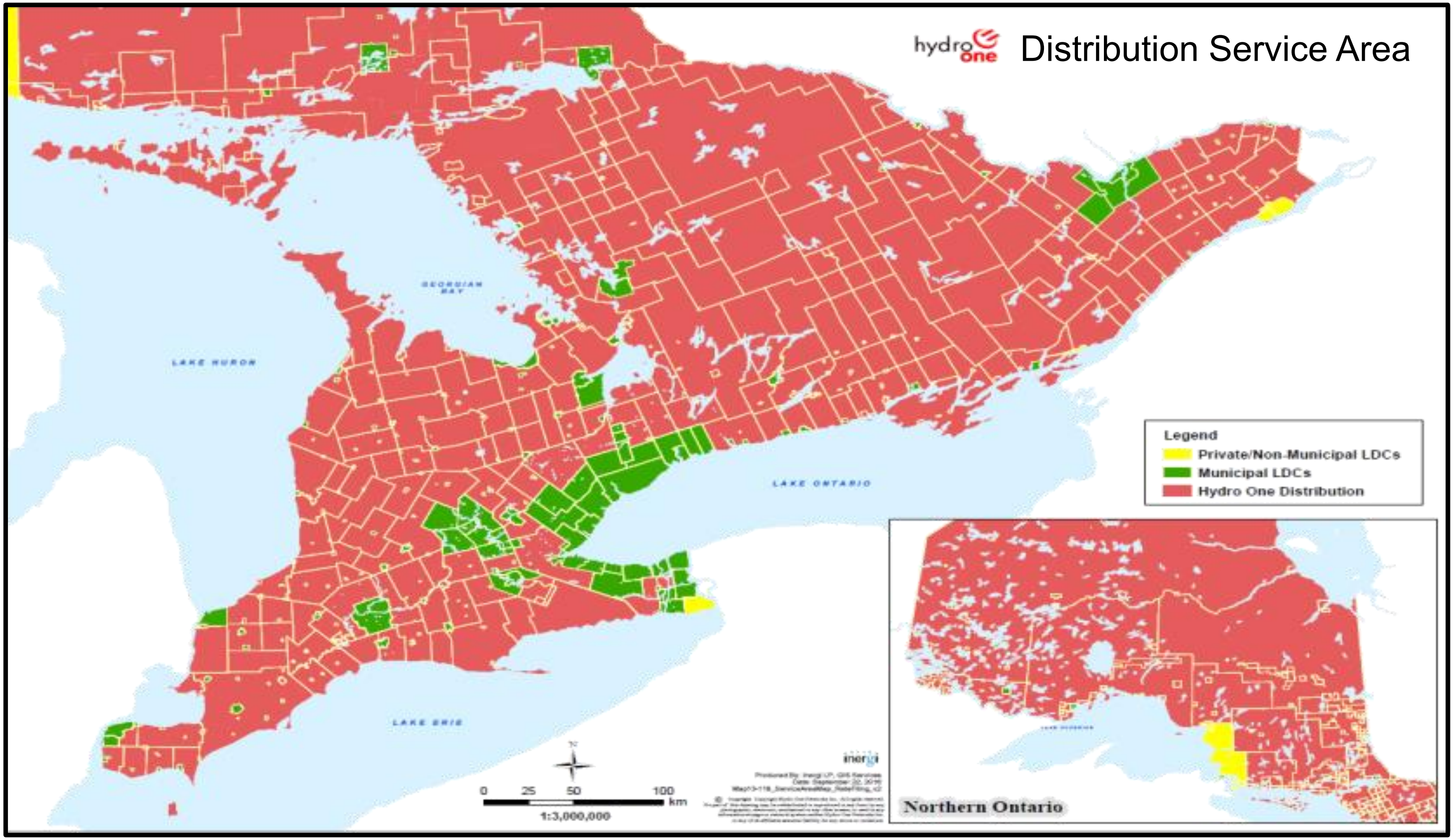
Hydro One's Role in the Ontario Electricity SystemG



Hydro One's Transmission System Map

Hydro One’s 230kV Transmission Lines

Hydro One's Distribution System MapG

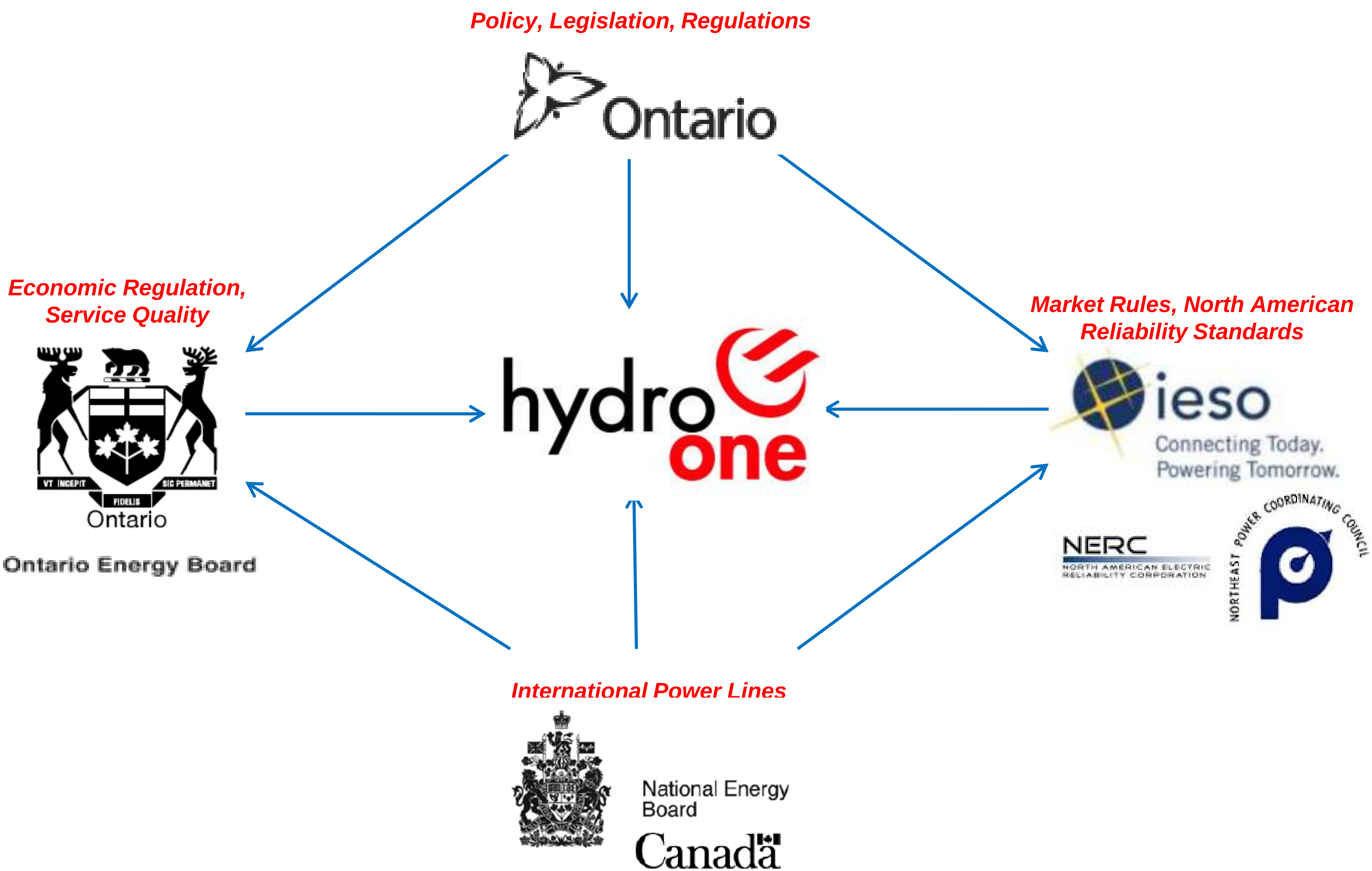


Hydro One's Rural Distribution Line

Overview of Hydro One' s Distribution SystemG

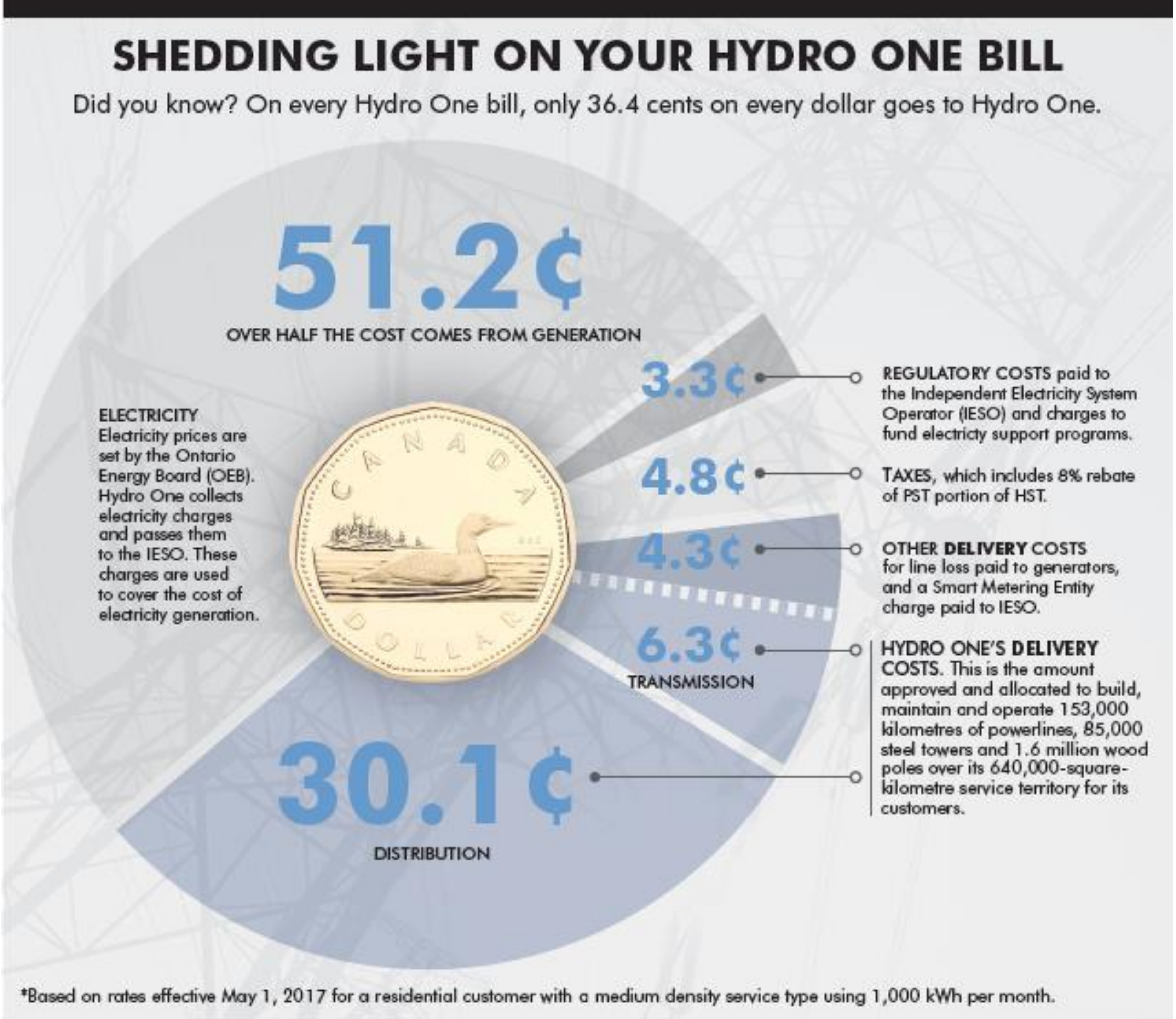
Service Area	Rural Service Area – 960,123 sq. km Urban Service Area – 677 sq. km
Customers	1.3 million residential and business customers as well as 55 local distribution companies.
Distributed Generation	Approximately 13,400 generators connected to Hydro One's distribution system.
Stations	Approximately 1,000 distribution and regulating stations.
Circuit Length	Approximately 123,000 km of primary low voltage distribution lines.

Ontario's Regulatory rameworkG



2018-2022 Distribution Rates Application

- Filed with the OEB March 31, 2017
- 5-year Incentive Rate-setting Application
- Includes a proposal for sharing earnings with customers
- Public hearing process about to start

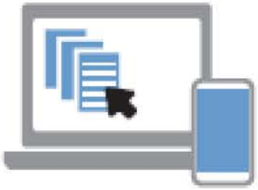

SHEDDING LIGHT ON YOUR HYDRO ONE BILL
Did you know? On every Hydro One bill, only 36.4 cents on every dollar goes to Hydro One.
51.2¢
OVER HALF THE COST COMES FROM GENERATION
ELECTRICITY
Electricity prices are set by the Ontario Energy Board (OEB). Hydro One collects electricity charges and passes them to the IESO. These charges are used to cover the cost of electricity generation.
3.3¢
REGULATORY COSTS paid to the Independent Electricity System Operator (IESO) and charges to fund electricty support programs.
4.8¢
TAXES, which includes 8% rebate of PST portion of HST.
4.3¢
OTHER DELIVERY COSTS for line loss paid to generators, and a Smart Metering Entity charge paid to IESO.
6.3¢
TRANSMISSION
HYDRO ONE'S DELIVERY COSTS. This is the amount approved and allocated to build, maintain and operate 153,000 kilometres of powerlines, 85,000 steel towers and 1.6 million wood poles over its 640,000-square-kilometre service territory for its customers.
30.1¢
DISTRIBUTION
*Based on rates effective May 1, 2017 for a residential customer with a medium density service type using 1,000 kWh per month.

Where your Distribution Charges go…

15%
OUTAGE RESTORATION

70%
KEEPING THE SYSTEM RELIABLE

Replacing worn out equipment and trimming trees to keep power lines clear, maintaining a modern, reliable system.



15%
CUSTOMER SERVICE

Providing customer service by phone or online, providing tools so you can manage your energy use, ensuring accurate and timely statements.

What our customers told us

Our Application focuses on customer needs and preferences:

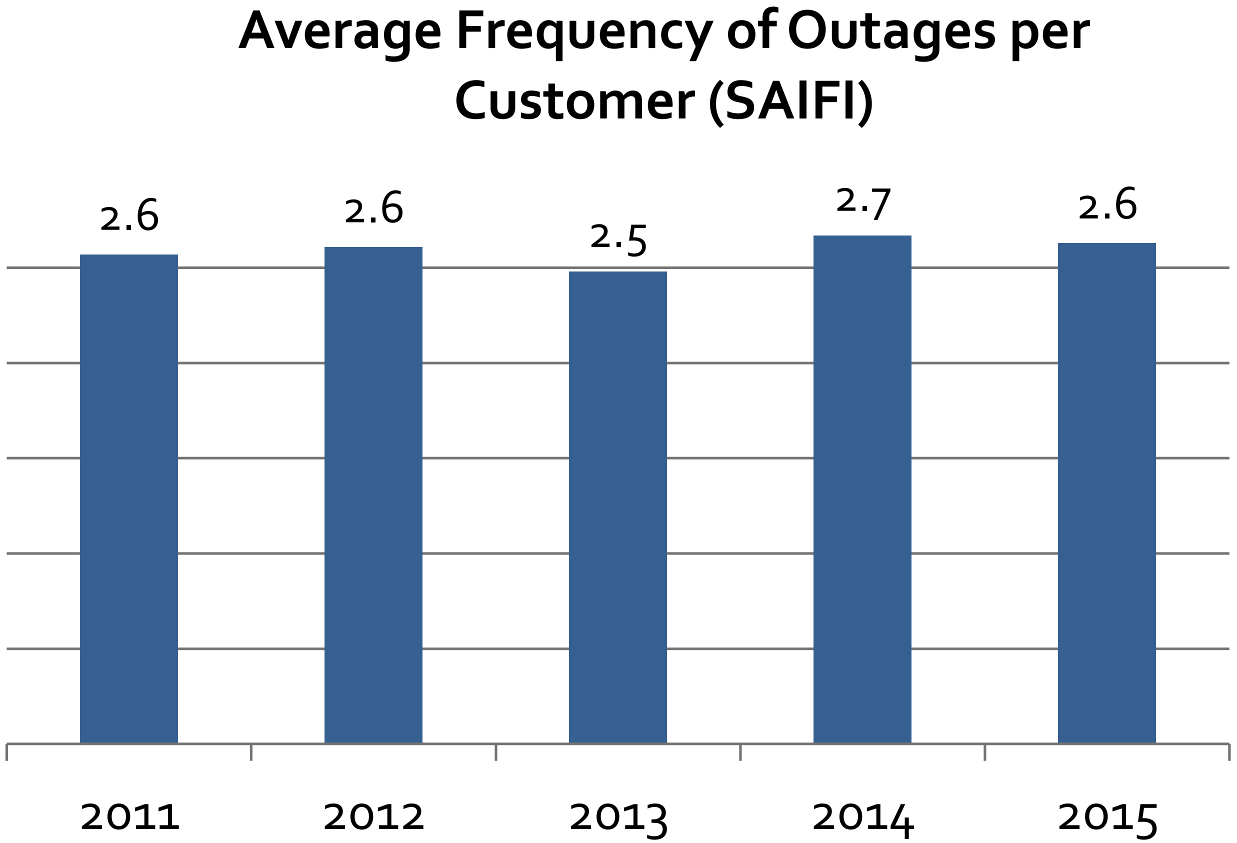
- **Keeping Costs Low**
  - *Keep costs as low as possible is customers' top priority.*
- **Maintain Reliable Service**
  - *Maintaining reliable electricity service is consistently second priority to cost.*
- **Large Customers**
  - *Large customers are more concerned with reliability and capacity.*
- **Manage Rate Impacts**
  - *Willingness to accept a rate increase to improve service level is limited.*

Hydro One's Rate ApplicationG

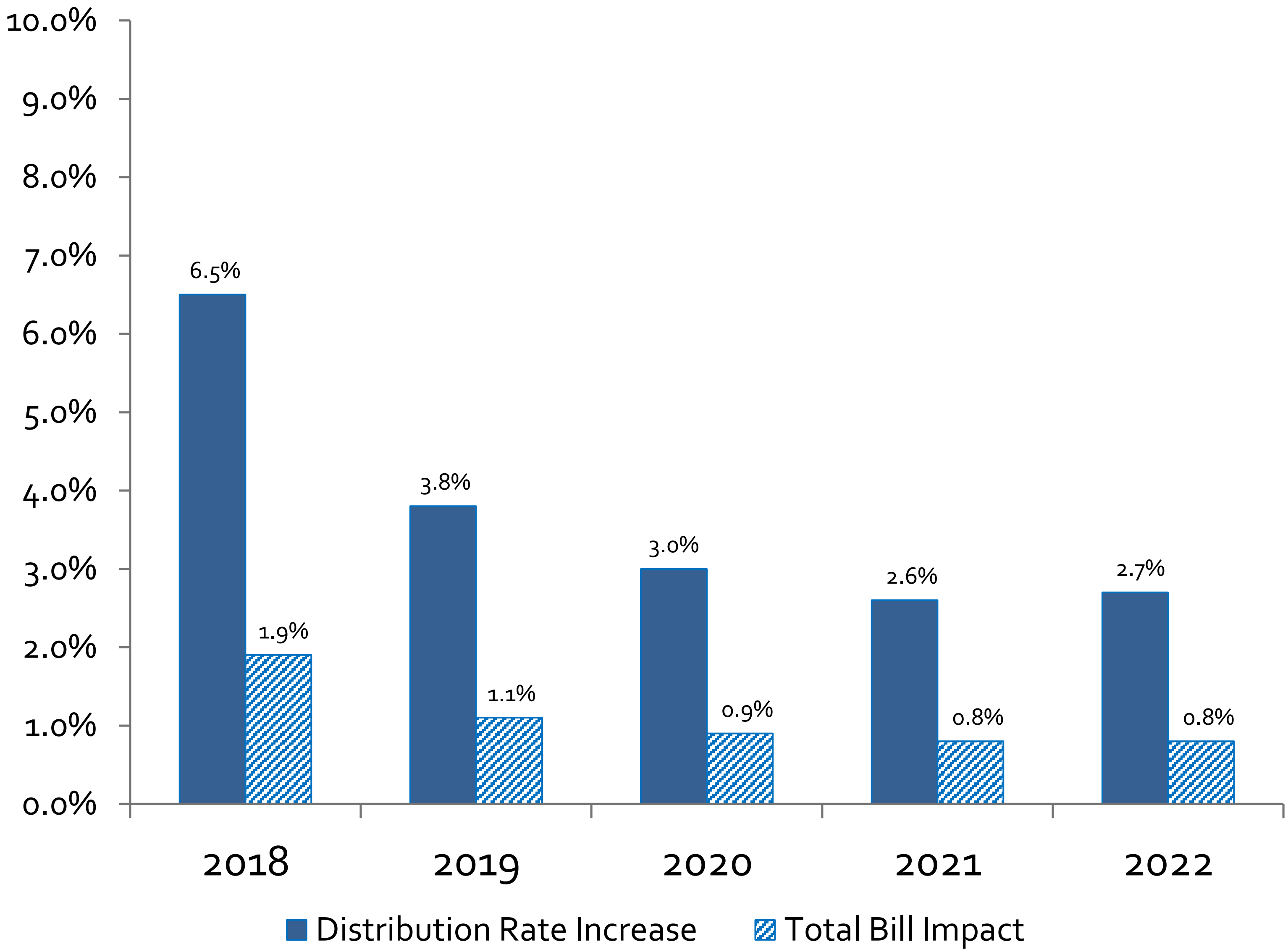
- Hydro One's rate application balances three considerations.

Hydro One's Rate Application – Asset Focus

- Hydro One's investment plan aims to maintain historic system reliability



Hydro One's Rate Application – Rate Impacts



Main Areas of Hydro One' Distribution Rate IncreaseG

Cost Drivers	2018	2019	2020	2021	2022
Operations, Maintenance and Administration	-0.1%	0.5%	0.5%	0.5%	0.5%
Capital Related *(e.g., poles, wires, and transformers)*	2.0%	2.9%	2.6%	3.4%	2.5%
Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Load Impact	3.0%	0.2%	-0.2%	-2.3%	-0.3%
Other Revenue and Rate Riders	0.8%	0.0%	0.0%	0.6%	0.0%
Total	**6.5%**	**3.8%**	**3.0%**	**2.6%**	**2.7%**

About Load Impact…

- Cost of distribution services is spread out among all Hydro One customers.
- Total electricity consumption has declined since rates were last set.
- This contributes 3% to the average distribution rate increase in 2018.

Next Steps

- OEB to issue a Notice of Application and Procedural Order outlining the provisions in the proceeding.
- The OEB plans to hold some community engagement meetings about our Application.
- Individual customers or groups that represent Hydro One's customers can become an active participant (*Intervenor*) or an observer in the proceeding by applying to the OEB.
- Hydro One to submit an update to its Distribution Rate Application in June 2017 to reflect its audited 2016 actual costs.

Hydro One and Métis Engagement Session
Toronto Room, DoubleTree by Hilton
Saturday, May 13, 2017

SESSION REPORT

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WELCOME

[redacted], **Session Chair**, called the meeting to order and introduced Métis Nation of Ontario Senator Larry Duval, Moon River Métis Council. Senator Duval provided the opening prayer.

INTRODUCTIONS

The following individuals introduced themselves, and in some cases expressed an area of interest or concern:

Regional Councilor [redacted] Region #2:

President [redacted] MNO Northern Lights Métis Council: mentioned that he was looking for more information on Hydro One.

President [redacted] MNO Greenstone Métis Council: mentioned that he was looking for more information on Hydro One.

President [redacted] MNO Thunder Bay Métis Council: personal introduction

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: personal introduction

Sara Jane Souliere, First Nations and Métis Relations, Hydro One: personal introduction

President [redacted] MNO Ottawa Métis Council: stated that she was in attendance to listen and learn more about Hydro One.

Ms. [redacted] MNO North Channel Métis Council: personal introduction

President [redacted] MNO North Channel Métis Council: stated that she wanted to bring information on Hydro One back to the citizens of her Council.

Rhode Thomas, First Nation and Métis Relations, Hydro One

President [redacted] MNO Clear Waters Métis Council: mentioned that he looked forward to learning more about Hydro One and sharing that information with the MNO citizens.

President [redacted] MNO Peterborough and District Wapiti Métis Council: added at that he wanted more information on the work of Hydro One. He also wanted to identify ways that Hydro One could further include the Métis in the work that they were doing.

Chair [redacted] MNO Peterborough and District Wapiti Métis Council: added that she was here to listen and learn more about the work of Hydro One.

President [redacted] MNO Niagara Region Métis Council: stated that he wanted to learn more about the changes that were coming at Hydro One.

President [redacted], MNO Grand River Métis Council: stated that she wanted to learn more about Hydro One, any upcoming changes and to be able to share that with the citizens.

President [redacted] MNO Oshawa and Durham Region Métis Council: added that there were concerns about the costs of delivery to northern communities. She was at the session to learn more and bring that information back to the community.

Senator [redacted] MNO High Land Waters Métis Council: personal Introduction.

Tausha Esquega, First Nations and Métis Relations Team, Hydro One: personal introduction.

Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One: stated that it was a pleasure to welcome all to the session. His department, he explained, had the responsibility of First Nations and Métis Affairs and he looked forward to renewing those relationships.

Senator [redacted] MNO Moon River Métis Council: mentioned that he looked forward to learning more about Hydro One.

Regional Councilor [redacted] Region #7: mentioned that they were looking to advocate for lower hydro rates for their citizens as well and lessening the environmental impacts of tree cutting by Hydro One in their region. She also added that they are interested in obtaining information on procurement opportunities with Hydro One and that there is also a need to clarify the costs around Hydro delivery charges for cottages.

[redacted] **MNO Veterans Council and Captain of the Hunt, Region #7:** personal introduction.

Regional Councilor [redacted] Region #5: stated that he wanted to learn more about Hydro One and take this information back to his communities.

Denis Tremblay, MNO North Bay Métis Council: personal introduction.

Chair [redacted], MNO Matawa Métis Council: personal introduction.

President [redacted], MNO Sudbury Métis Council: personal introduction.

Rob Berardi, A/VP, Shared Services, Hydro One: personal introduction.

Kyla Thistle, Contract Officer, Supply Chain, Hydro One: personal introduction.

Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One: personal introduction.

[redacted] **Treasurer, MNO Sunset Country Métis Council:** personal introduction.

President [redacted] MNO Kenora Métis Council: mentioned they had a municipal hydro supplier in Kenora but many of his citizens were Hydro One customers.

President [redacted], MNO Superior North Shore Métis Council: mentioned that he had concerns around hydro costs as well electromagnetic fields. He also had some questions about the sale of Hydro One shares to First Nations and if this same opportunity was going to be provided to the Métis in the province.

President [redacted] MNO Credit River Métis Council: she introduced herself and mentioned that she hoped to learn more about new developments at Hydro One.

Regional Councilor [redacted] Region #4: stated that he was here to listen and provide input on Hydro One issues as they affect the citizens of Region 4.

Regional Councilor [redacted] Region ##3: personal introduction.

Daniel Charbonneau, First Nations and Métis Relations, Hydro One: personal introduction.

[redacted] Director, Intergovernmental Affairs, Métis Nation of Ontario: stated that the MNO has had a relationship with Hydro one for a number of years but not at this level. She stated that they could work together to make a difference and mentioned a forum that had been held to talk about procurement. Mr. Scott Patles Richardson was also working directly with Hydro One to address procurement initiatives.

Imran Merali, Interim Director, First Nation and Métis Relations, Hydro One: personal introduction.

Devi Shantilal, First Nations and Métis Relations, Hydro One: personal introduction.

MNO Vice-Chair [redacted] Provincial Council of the Métis Nation of Ontario: added that it would have been helpful to have the members of all their Consultation Committees here to learn and contribute to the conversations and maybe this could be considered for the future. There were also different Councils that could contribute such as the MNO Youth Council, the MNO Veterans Council and the Women's Secretariat of the Métis Nation of Ontario.

INTRODUCTORY REMARKS

Mr. Pugliese welcomed all the participants to the session on behalf of Mr. Mayo Schmidt, President and CEO of Hydro One, and also his colleagues present at the session. He thanked Senator [redacted] for his prayer and acknowledged the traditional territory of the Mississaugas of the New Credit First Naiton. He mentioned that this was an opportunity for dialogue and that they were here to listen and take that information back to Hydro One. He explained that this was not the last gathering but rather they would like to do this on an annual basis. They also hoped that they would have the opportunity to meet with the councils as well. He introduced himself with some background information.

Mr. Pugliese continued by providing some background information on Hydro One including an overview of how Hydro One interacts with First Nations and Métis communities across Ontario. He said that there were many misconceptions of the work of Hydro One and there was a need to communicate more with Ontarians around this. They were not responsible for power generation or for rate setting; however they were responsible for power distribution. He said that they have been undertaking this education piece.

In terms of privatisation, he explained that one year ago the government decided to sell the assets of Hydro One and now Ontario holds about 49.9% of the shares; Hydro One had transitioned to a private company.

As the company changed direction from a Crown corporation to a public company, there was an opportunity. In this shift there were two (2) things they had embarked on:

- The first was education, to help explain Ontario's complicated electrical system including the regulators, etc. Hydro One has started to uncover what can be addressed and asked for the opportunity to first understand and then work on the things that they can change.
- The second task was related to advocacy. Hydro One owned the hydro bills and maintained relationships with communities and customers. Hydro One had an impactful voice in advocating of behalf of its customers.

Mr. Pugliese reiterated that the session was not designed to be a consultation rather it was the first step in a series of discussions that would lead to change. He also recognized that change is indeed required, particularly in the area of affordability.

Hydro One staff here at this session would be providing presentations that focused on customers and communities. Hydro One wanted to hear how people thought Hydro One could make Hydro One a better company, as this would give them an opportunity to grow Hydro One. He said that Hydro One was hoping to be a good model for privatisation in this country. Hydro One hoped that they could build their strength on how they interact with Indigenous people everywhere.

In terms of First Nations and Métis relations, Hydro One viewed them as more than partners, he explained, as they were integral to their business relationships. He stated Hydro One would like to see the corporation at the forefront on these types of relationships; he understood that they did this well in some cases but there was room for improvement. Partnerships meant procurement opportunities, employment opportunities and capacity building.

Hydro One has assembled a new executive team and launched a number of cost saving initiatives. Hydro One was also looking at growing the business in the area of advocacy and education as well. In terms of education initiatives, Hydro One wanted to inform the public about the mandate of the Hydro One in terms of power delivery versus generation and the issues around the rates. He stated that 37 cents on each dollar could be attributed to Hydro One's transmission and distribution system while more than 50 cents on the dollar came from power generation. The 37 cents is an average, and it is for each dollar collected on the bill. In terms of advocacy, they were looking at opportunities for advocacy on behalf of all communities to the regulators and mentioned the example of addressing the distribution rates. He explained that the rates are impacted by population density and infrastructure costs in rural areas. He also explained that they would be looking at rate reduction coming into effect in September this year. Hydro One played an advocacy role on the First Nation shares and provided information to the Ontario Energy Board on this matter.

They have made a number of changes over the past two years, Mr. Pugliese explained, including changing the winter moratorium to June 1. Hydro One has also reconnected a number of customers while waiving the reconnection fee. For those in arrears, they have been working on building a new collections program and currently 60% of those who have been disconnected or were in arrears are in new affordable payment plans. Hydro One has been working with community members to identify any issues with their bills and establishing payment plans and Hydro One was working with administrators on supporting community capacity building. Hydro One was shifting their view as a company and reaching out to customers to address their concerns, solve problems and be more accessible. Hydro One was looking at new approaches and this session was an example of that. Hydro One is looking for feedback on updating Hydro One policies going forward.

Senator [redacted] asked if the hydro rates would be lowered for rural areas. Mr. Pugliese stated that they were always looking for the best ways to use their assets and their customers would see significant reduction starting in July or September this year upon implementation of the Fair Hydro Plan

Regional Councilor [redacted] stated that they would like to see more procurement and employment opportunities for their citizens. One of the issues with employment related to housing in her region; individuals could not move to an area to work for Hydro One if there was no housing available in those communities. Mr. Pugliese noted that this was a complex issue and they needed to think this through with their procurement unit. He acknowledged that they could not solve all the issues but they needed to look at what opportunities could be identified.

President [redacted] asked if this new hydro distribution reduction plan meant that there was one flat rate for the province. Mr. Pugliese stated that essentially this was true - 2/3rds of the province was rural and paying higher rates but now this will be equalize, but those paying lower rates will not be seeing higher rates. He stated that the rural rate will be lowered to match the urban rate and they will do this using the existing tax base; this was a policy decision.

Regional Council [redacted] asked for a definition of "rural" and "urban". Mr. Pugliese stated that an upcoming presentation will provide this information in detail.

[redacted] referred to Mr. Pugliese's update on the future expansion of Hydro One and asked if this meant delivery to the United States. She also asked how they would look at servicing areas in Northern Ontario that did not yet have service. Mr. Pugliese stated that in terms of expansion, there was wide spread potential across Canada, North America and across the world but they understood that there was still work to be done here in Ontario. He explained that they had bid on the work for the East-West Tie but were not successful; they were looking for opportunities to partner in order to expand. They were also looking for these kinds of partnerships with First Nation and Métis communities. He stated that Hydro One saw the need to build up more in Ontario and they were committed to doing that.

President [redacted] asked if they would be talking about Hydro One employment. She stated that they had citizens that have graduated and were having trouble entering Hydro One's employment programs, such as the apprenticeship programs. She asked if there was an employment coordinator that could assist them with the process. Mr. Pugliese said that they would discuss this in more detail later on in the day but he realized that they still had a lot to do in this area. They have to work with Unions to increase the number of apprenticeships. They are working with their Human Resources group to make those changes. He said that they have not done particularly well in this area but they needed to track and report on any progress in this area. President [redacted] stated that it was disappointing to hear that this process was just starting. Mr. Pugliese stated that there were parts of Hydro One where this had been done well and there were a lot of students and apprentices but there were areas that still needed to be addressed.

[redacted] stated that he was concerned that the reductions in bills now may mean a big increase in the future to make up for it. Mr. Pugliese stated that they were not here to defend this policy change, but that he would say that the increases in green energy generation have caused changes, which have meant there had to be cost adjustments as this system was a cost recovery system. He said that they had spread the costs related to the rate reductions over the life of the assets and depending on how those contract renewals were negotiated, he did not believe that there would be an escalation. He explained that if the contract remained unchanged, the consumer would likely see those escalators. It was important, he added, that they asked those questions and understand the facts.

President [redacted] asked about recouping those losses of funds with those reductions, as Hydro One was a business now. She also asked if the northern consumers have been overcharged all this time and if there would be a retroactive rebate for that. Mr. Pugliese stated that Hydro One did not set the rates; those rates were established by the Ontario Energy Board. He explained Hydro One prepared a submission to the OEB to outline what their costs would be to provide the distribution of the energy; this was what they needed in order to do their work. The OEB could approve this work plan and then Hydro One started spending to get the work done. The rate reduction was a result of the government decision and this was being funded by the government, not Hydro One. The costs to cover this reduction would come out of the Ontario tax base. In terms of an overcharge to northern consumers, Mr. Pugliese stated that they did not look at the rates this way, it was a policy maker's decision and it was not seen as an overcharge; it was a cost recovery system.

Regional Councilor [redacted] stated that, in terms of the East-West Tie, there were eleven Métis communities impacted by that work. He suggested that the Hydro One bid to undertake this work should have included the Métis and that Hydro One should have a Métis Relations person on staff that was familiar with their governance structure and processes. Mr. Pugliese thanked him for his comments and stated that their submission for the East-West Tie was submitted in 2014 and he realized that they should have included others; they intended to change that approach as they went forward.

President [redacted] asked about the possibility of using more non-wood poles for the lines, as this would save more trees. Mr. Pugliese stated that Mr. Jesus would speak to this later today but he understood that non-wood poles were significantly more expensive than wood.

[redacted] stated that Mr. Pugliese had mentioned that they needed to inform themselves with the facts regarding energy in Ontario and she asked where they could go for this information. Mr. Pugliese responded that they could call Hydro One at any time or consult their website where there was a lot of information on energy policies in Ontario. He added that they had a lot of experts that could come to the community and spend some time providing the information they required. Hydro One, he explained, was a neutral party and could provide impartial information, advocate as required, but they needed partners in that advocacy role.

Senator [redacted] stated that they received a 10% discount from province for their hydro bill and he asked if this would be removed because of the upcoming rate reductions. Mr. Pugliese said that this sounded like the R1 adjustment and the HST and he said that this would be unaffected by the upcoming rate reductions.

Mr. Pugliese ended this part of the presentation with a video outlining the changes in Hydro One and their purpose of "turning on the power of possibility". It was noted that Hydro One welcomed feedback on the video.

CUSTOMER SERVICE

Mr. Imran Merali, Hydro One, provided an overview of his PowerPoint presentation entitled "Customer Service". He asked for views on Hydro One customer service.

The following comments were provided by the participants:

- [redacted] mentioned that when she has had to call Hydro One, she was transferred a number of times to different people. She suggested that they need to have a better idea who to direct which calls to.
- **Regional Councilor** [redacted] agreed stating that he has called about his hydro bill and the person answering the phone was unable to answer his questions. He stated he had a question about usage when he was not in residence.
- **Regional Councilor** [redacted] mentioned that she had began her inquiry in French and mentioned that the French provided was not Canadian French but rather Parisian French. She also mentioned that she had shut off everything at her cottage and then was told she should have shut off her breaker and since she was six hours from her cottage, she had to get someone to go there to shut it off. She never received a follow up call from Hydro One to say it was shut off.
- **President** [redacted] had issues with how much power was used in a residence that had everything shut off. When she called about this, she was told to wrap her hot water heater but the hydro costs continued to rise. She was not sure why her hydro bill would be higher than her neighbours and could not get a satisfactory answer on that from Hydro One.
- [redacted] asked how often Hydro One conducted house calls. Mr. Merali noted that these were frequent and Mr. Jesus could provide more detailed information. Ms. Clarke suggested sending an email with a photo of the technician, as she had seen this done with some other companies and it was a useful tool.

Mr. Merali thanked them for their comments and stated that, at Hydro One, all staff were responsible for customer service. Hydro One was anxious to hear the feedback of their customers and looked forward to improving their practices. He provided an overview of the Flip the Switch campaign, which was designed to solicit the views of their customers and make the policy changes to address their issues. One of the actions they have taken was inviting all their Executives to take calls in their call centre so they could learn more about customer concerns and then to go back to their sections and make the necessary changes. He provided a video to show this.

He provided an overview of the some of the transformational changes they were already making and provided an overview of the vision of Hydro One. Some changes included opening their call centre on Saturdays and increasing the support electronically as not all issues needed a verbal exchange. They want to be easy to do business with and increase their work on education, advocacy and responsiveness. He spoke to the importance of education and ensuring that their customers knew what Hydro One was responsible for and what was not their responsibility. Mr. Merali provided an overview of the Fair Hydro plan, which meant significant rate reductions through the reducing of the global adjustment charge and lowering the delivery charge for rural customers including eliminating the delivery charge for on-reserve customers. He stated that they would see a reduction of their hydro bills this summer with the average bill being reduced by 33%.

Regional Councilor [redacted] noted that they had not had a discussion on eliminating the delivery charge for those customers on-reserve. Mr. Merali explained that the First Nations leadership, through the Chiefs of Ontario, advocated for the elimination of this charge and Hydro One had supported that. He said that nothing similar existed for the Métis in Ontario. The Regional Councilor stated that they had not even had an opportunity to have that discussion. Mr. Merali explained that this discussion was not initiated by Hydro One and if the Métis wanted to lobby Ontario for something similar, Hydro One would support that as well. When asked why it did not automatically apply to the Métis, Mr. Merali explained that it currently only applies to residential properties on-reserve. Regional Councilor [redacted] stated that they would need to follow up with the province on this issue.

Mr. Merali continued with his presentation providing an example of a customer bill explaining that there would be significant saving on bills such as this one, which was rural density and high consumption.

President [redacted] asked if these reductions were for individuals only or also for businesses. Mr. Merali clarified that this applied to individuals and small businesses but the delivery charge reduction was only for residential customers. The most significant was for rural residential customers who would see a reduction of approximately 40% on their hydro bill.

Regional Councilor [redacted] asked about how they defined “rural” versus “urban” and what the formulas were in figuring out rates. Mr. Merali explained that this was defined by the OEB and more information could be found on their website. Essentially it involves how many people lived in a geographic area and the number of customers per km of line.

President Trent [redacted] asked about distance from power generation facilities mentioning that he lived approximately 400 yards from a 4500Mw hydro plant and he was paying very high delivery rates. Mr. Merali stated that when the OEB set the rates, it was the same no matter where they lived within a certain geographic area and, until now, rural residents paid more no matter where they lived. Mr. Oded Hubert, VP, Regulatory Affairs, stated that North America has a very large power grid and the hydro any individual might receive, might not come from close to them; they needed to depend on the entire structure for reliability.

Regional Councilor[redacted] asked how he would describe the density zone and how defining those areas were arrived at. Mr. Hubert stated that this was defined in a manual way previously by Hydro One staff (counting houses, kilometres of line, etc.) but now Hydro One was using a geographic information system to assess density and male these determinations. "

Mr. Merali continued on with his presentation providing an overview of the revised customer relief program. He explained that effective April 25, 2017, Hydro One was providing additional relief to assist customers that had accumulated significant balances on their accounts during the winter. He provided an explanation of a number of policy changes in this area. Hydro One was also making a number of customer commitments including the introduction of service guarantees. One of these was an automatic $75 credit for missing appointments they had booked in residences and also if they did not hook up their hydro by the time five days had passed. Hydro One was also introduced a new hydro bill and maintaining their record of very high bill accuracy.

Senator [redacted] asked about the estimate that is sometimes part of his bill, which caused some issues when the bill estimate was very low and then very high. Mr. Merali stated that they wanted to read the meters on a monthly basis to avoid these estimates and they could also set up budget billing, which meant they could set the bill based on a monthly estimate and this would be reconciled at the year's end. There were a number of new tools and technology for their customers to use to report their meter reading.

Mr. Merali provided an overview of all the ways they communicate with their customers including increased use of e-billing, high usage alerts, new website with customer portal and the redesigned bills.

[redacted] asked if Hydro One had looked at an incentive for customers to sign up for e-billing such as an eliminated administrative fee. Mr. Merali stated that they did not charge for paper billing so there was no change for e-billing but they were looking at a campaign to increase the use of e-billing. Ms. Clarke noted that incentives could give people a little more money in their pocket that could applied during the winter months.

President [redacted] asked about the effectiveness and quality of the smart meters that were installed, as some in the Sudbury area felt their hydro costs went up at this time. Mr. Merali said that the consumption was unchanged with the arrival of the new smart meters; he suggested that this may have coincided with government change of pricing for hydro during this same time.

[redacted] suggested that Hydro One had cut down a number of trees in the North Bay area to avoid interruptions due to weather but they had not cut down the right trees. Mr. Merali stated that he would be happy to follow up on this off line and check into this. In addition, Mr. Jesus would be adding additional information on hydro reliability later in the day.

[redacted] asked if Hydro One played any role in addressing the issue with door to door energy contract sales persons. He also asked if those locked into those contracts would see any rate reductions. Mr. Merali stated that Hydro One has no role to play with those outside companies but the Hydro One website has information on how to compare costs. He did not know if there were rate reductions on retail contracts but he agreed to follow upon on that.

HYDRO ONE DISTRIBUTION RATE FILING (2018-22)

Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One Mr. Hubert described how Hydro One is seeking approval from the OEB with a distribution rate application that will provide the revenue required to operate the system for the next five years (2018-2022). This is the standard application that Hydro One now has to complete every five years. Hydro One has filed with the OEB a significant amount of information to make their determination, including the proposed rate increase and total bill impact. The Premier asked Hydro One, among others, for advice on providing relief to rural customers, given that the delivery charge is often higher than the usage charge. Mr. Hubert provided an overview of Ontario's Electricity system including how the electricity flowed from the generators to the customers in Ontario. President Yvonne Jensen asked why a transformer would ever blow up.

Mr. Hubert stated that this could be caused by an electrical fault, lightning, a manufacturing flaw or a malfunction within the system. Mr. Jesus explained that some assets were getting older and there could be some insulation defects internally. Transformers had a 40-50 year life span with poles lasting a little longer. Mr. Hubert added that asset monitoring took place over the life of the asset. When asked if this was dangerous and about PCBs, Mr. Hubert explained that there might be a small oil spill and there were fewer transformers with PCBs because they are being replaced. In accordance with federal legislation, these would be all removed by 2025.

[redacted] asked if she was buying a home and this type of oil spill had happened from a transformer, would she be informed of that. Mr. Jesus said that this would have to be reported to the federal government but the information might not necessarily get to her as the homeowner. Mr. Hubert explained that regulations are in place around who had to be informed. Ms. [redacted] asked if she was selling her house, she would need information on how the cleanup was done. Mr. Hubert stated that this was out of his area of expertise but they could follow up on that question and get back to the MNO on that.

Mr. Hubert continued with his presentation providing an overview of the Hydro One distribution system and Ontario regulatory framework. Distribution rates are set by the OEB and he explained that their application was filed with the OEB on March 31, 2017. The public hearing process was about to begin. He provided an overview of the breakdown of the electricity costs to customers.

Christa [redacted] asked if environmental costs were included in the 51% of the bill that covers commodity costs and Mr. Hubert stated that it was and the generators are accountable for the costs in this portion of the bill. This includes costs to provide the service today but it may also include a provision in consideration of the implications for the future.

President [redacted] asked for an explanation for the reference of loss of power on his hydro bill. Mr. Hubert mentioned that this was covered in the "Line Losses" at 4% on the graphic and this was in reference to power that was lost in transit. Generators have produced the power and therefore must be paid for it, and Hydro One has to account for any power loss and as long as the transmission and distribution were done as efficiently as economically possible, they could expect to recoup this loss. Mr. Hubert was asked where they would get the incentive to make efficiency improvements when they received compensation for their losses. He responded that this came in up in the OEB hearing as well and that Hydro One seeks to reduce losses where it is economic for it to do so in the areas under its jurisdiction.

Senator [redacted] asked about the forestry work that needed to be done to cut back trees from the lines and if this work would be undertaken by contract workers or Hydro One workers. Mr. Hubert said that they would use a mix of external and internal workers for that.

[redacted] asked about the new rate application and if there would be increased costs related to security. Mr. Hubert stated that they do take this into consideration and there were international standards for reliability and this included critical infrastructure protection. This also included protecting the copper in their equipment.

Regional Councilor [redacted] asked about species at risk legislation when it comes to cutting trees down to protect the lines. In the past, they were told that there was no budget for mitigation in these cases. Mr. Hubert mentioned that he was not sure in that case; for larger projects they needed to undertake an environment assessment. He said that he would have to follow up with MNO on this particular question.

[redacted] asked about options for putting their lines underground in the future. Mr. Hubert stated that the main issue was costs; this might be economically possible in urban areas but cost prohibitive in rural areas. Mr. Jesus stated that this would cost 10-20 times more than the construction of overhead lines.

Mr. Hubert continued with his presentation outlining where the revenues collected for distribution are spent and invested. He said that 70% went to keeping the distribution system reliable, 15% went to outage restoration and 15% went to customer service. Customers had told Hydro One that keeping costs low was the top priority and maintaining reliable service was the 2nd priority. He stated that this means “maintaining” the current level of reliability, as improvements would involve raising the current costs. He asked for the participant’s feedback on these priorities.

Regional Councilor [redacted] stated that this was a challenging situation in terms of costs as the Metis would likely agree to lowering costs as a priority but would not want this to impact on their traditional way of life. She felt that this was something they, as Metis people, would likely want to discuss in more detail.

Mr. Hubert continued with his presentation explaining the rationale of their rate application to the OEB considering customer needs, asset needs and rate impact among others. While the government's Fair Hydro Plan may result in bill reductions of approximately 30-40, it was Hydro One’s job to complete the submission ensuring that they received enough funds to keep up the needs of the distribution system. He provided an overview of the costs that were included as part of the application for 2018-22 which showed an increase in the areas of operations, maintenance, capital related costs, taxes, load impact and other revenues and rate riders. The largest increases were in the areas of capital infrastructure costs and load impact adjustment over the next four years.

[redacted] asked about the impact of the changes to alternative power within the province. Mr. Hubert said that many that were producing alternative power for the grid are not using this in their own homes but were selling it back to the grid. These individuals were still accessing power from the grid. He said, when looking at their rates, the customers wanted

Hydro One to look for increased productivity and efficiencies before coming to the customer with higher rates to cover the costs and they did this before hydro one make their rate application to the OEB.

Regional Councilor [redacted] asked if there was anything in the five-year rate plan that addressed the ring of fire development with the Province of Ontario. Mr. Hubert stated that this was not part of this proposal as Watay Power was working on this; this application is specific to distribution rates.

[redacted] asked about possible escalated costs in the future (post 2022) based on the budget here on the distribution side. He asked if this could have an effect on individual bills. Mr. Hubert stated that this could have an impact depending on the commodity price; a government initiative would have to be sought to offset those costs.

Mr. Hubert continued outlining the next steps in the OEB application process. The OEB would issue a public notice about the application and then there would be public hearings. Individual customers or groups representing Hydro One's customers could become intervenors in that process or they could be observers.

Regional Councilor [redacted] asked what their status as Metis people would be within the hearing process. She asked if they would return to this process to feed into those OEB hearings. Mr. Hubert stated that this session was not part of that consultation process; it was an engagement initiative. He also said that the intervenor process completely handled by the OEB. He suggested that if MNO wanted to participate in the OEB hearings, they needed to register with the OEB. Regional Councilor Richardson made it clear that they had Aboriginal rights that did not fall under OEB regulations. She said that they told their people not to participate in those processes as they were a right bearing people and they had a process for consultation already in place through their internal structures. Mr. Hubert stated that he would defer to the First Nations and Metis Relations section of Hydro One to comment on that. Mr. Charbonneau stated that this was not their process but rather OEB's and Regional Councilor [redacted] asked if the OEB was the Crown in this case. Mr. Charbonneau was not sure as he could not speak on behalf of the OEB; he was unsure if the OEB could trigger the duty of consult. It was suggested that the MNO would have to go to the Minister of Energy to address this, as this has not been delegated to Hydro One. Regional Councilor Richardson stressed that she needed some information on where she should go to follow up on this important question.

OPERATIONS – HYDRO ONE RELIABILITY MEASURES

Mr. Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One, provided an overview of his PowerPoint presentation entitled "Reliability Performance Overview". He said that he would be looking at the distribution and transmission systems and how Hydro One was directing investments to maintain reliability. He provided an overview of the customer engagement initiative which took place in 2016 and conducted by a third party. The focus of response had asked Hydro One to keep the hydro costs as low as possible with the second priority being reducing the number of outages.

Mr. Jesus provided an overview of the process to get the electricity from the generator to the customer. He mentioned, in response to the question earlier in the day regarding non-wood poles and he stated that these poles were very costly compared to wood poles, from 10 to 20 times the cost. His presentation concentrated on the transmission and the distribution systems and addressing reliability within those systems. In terms of the transmission system, the primary cause of interruption was weather and equipment failure. There was a marked difference in the reliability of the system in the north and the south. Hydro One was maintaining reliability in the transmission system by increasing capacity investments (lines), leveraging technology and reducing planned outages by bundling work among other initiatives.

[redacted] asked about the impact of solar flares on hydro reliability and also if they would be able to access power from other jurisdictions (other provinces or the United States) if needed. Mr. Jesus replied that they had built a system to address the possibility of geomagnetic outages. He said that they did have those connections to other jurisdictions but Hydro One was really seen a leader in terms of hydro transmission and distribution.

President [redacted] said that they had many power surges in their area and she asked about the cause of this. Mr. Jesus said that he could not speak specifically to her situation so they could talk offline about that but generally there were a number of possible causes including weather, an issue with the line among others.

Regional Councilor [redacted] asked how often Hydro One flew over their lines. Mr. Jesus said that there were regulations they had to adhere which stated that they had to every two or three years. Regional Councilor [redacted] also asked about AC and DC lines. Mr. Jesus explained that DC lines were normally used for great distances but they did not have DC lines anymore; they had a DC connection with Hydro Quebec and they were proposing a DC connection to Pennsylvania. To convert lines from AC to DC was costly and it was not seen as necessary in the distances they were talking about.

Mr. Jesus continued with his presentation stating that the primary causes of interruption in the distribution system were from tree contacts and equipment failure.

President [redacted] asked if new research has gone into non-wood poles. Mr. Jesus stated that the poles were mostly wood still as it was more expensive to use non-wood poles. He did say that they were looking into other technologies in some areas but steel was cost prohibitive.

Regional Councilor [redacted] asked what the wood poles were treated with and it this could negatively affect vegetation in the area. Mr. Jesus was not sure and he stated that he could follow up on that and get back to the MNO.

[redacted] asked who owned the poles in rural areas. Mr. Jesus said that Hydro One owned these poles up to the property line of the individual; the owner was responsible for the poles on their own land. Mr. Hubert noted that if a customer had to bring in the electricity to their own home, they do get some credit for distribution and do not necessarily have to pay the full costs of installing the lines to serve their property. These stipulations were all laid out by the OEB.

Regional Councilor [redacted] asked what would be the reasons for interruption if the copper was stolen by a thief. Mr. Jesus stated that this would likely be under equipment failure or possibly unconfirmed cause.

[redacted] asked if Mr. Jesus has ever heard of smart meters catching on fire. Mr. Jesus did not think this could happen. Mr. Pugliese mentioned that there was a story in the news where the face of the meter caught on fire but the fire itself was not caused by the meter. If, in the future, there was an issue with the meter, Hydro One would address that.

Mr. Jesus continued with his explanation of the distribution system stating that there were longer outages reported by customers in rural areas but it was difficult to find the outage. For this system, it was not a smart response system as they depended on customers notifying them of where the outage had occurred. Hydro One recognized that the reliability in these areas was not very good and they were working towards improve that by leveraging the meters to show the outages so the crews find the outage cause and location. This was all being done to minimize the impact of the outage on the customer. He outlined some programs they were undertaking to maintain reliability in the distribution system such as the renewal programs to replace aging equipment.

President [redacted] asked if power outages were identified by the length of time the power was out, as some were just out for a few seconds. Mr. Jesus said that those less than one minute was a momentary outage and sustained outage was more than one minute.

EMPLOYMENT – OVERVIEW OF HYDRO ONE ABORIGINAL EMPLOYMENT AND TRAINING

Devi Shantilal, First Nations and Métis Relations, Hydro One provided an overview of the Employment and Training presentation. She explained that no one Hydro One Human Resources was in attendance at the meeting and that if she could not answer questions raised, she would follow up after the meeting. She explained that Hydro One was committed to providing employment and training opportunities through apprenticeships, co-ops and internships.

[redacted] asked for information on the percentage Métis employees at Hydro One, including the percentage in management or senior positions. Ms. Shantilal indicated that the numbers are based on voluntary identification and committed to follow up on finding this information. She added that there were on-going diversity support systems for example was an internal women's network within Hydro One and that Hydro One was looking at launching additional initiatives to support various diversity groups to focus on awareness training and other issues. She further noted that that Hydro One has a diversity consultant and there are ongoing efforts at the senior management level and they were looking at initiatives for supporting Aboriginal employees. Ms. [redacted] suggested using the terms "First Nation, Inuit and Métis" rather then "Indigenous" or "Aboriginal" as people generally did not like the umbrella terms. Ms. Shantilal acknowledged this request and added that Hydro One used the phrase "First Nations and Métis Relations training" and they sometimes use the terms "Indigenous" or "Aboriginal" in existing material but they would look changing this terminology. Ms. [redacted] asked if the Hydro One was addressing the recommendations of the Truth and Reconciliation Commission recommendations. Mr. Pugliese stated that they did and they were looking at taking this further to ensure that all leaders in Hydro One had an enhanced level of cultural awareness. There are 50 plus leaders to go through this training, which would immerse them in all issues.

[redacted] asked about the interview techniques of Hydro One, as many First Nation, Inuit and Métis persons were more visual in terms of a communication style. She recommended using different interview techniques and not just the standard format in order to be responsive to different ways of learning. Ms. Shantilal indicated that when she went through the process, there were a number of different styles used that would allow individuals with different strengths to use that opportunity to showcase their strengths but she would follow up with Human Resources to find out more on this.

[redacted] asked what was involved in Hydro One's Aboriginal cultural awareness training and where did the information come from. Ms. Shantilal stated that the information used in the training comes from various sources, including the MNO website. The request was made by MNO representatives to see the material used in the Aboriginal awareness training. Mr. Merali indicated that Hydro One was in the process of refreshing their training and they welcomed feedback on the new training package. Ms. [redacted] indicated that MNO would be pleased to review the training package and they could also provide training and perhaps make it more interactive. Ms. Shantilal stated that they could discuss this.

Regional Councilor [redacted] stated that any region could provide this cultural awareness information and that they could work in partnership; he invited Hydro One to come meet with them and their knowledge holders in the regions. He also asked how their hired for promotions and if they focused their efforts on this from within their organizations. He also asked where their training facilities were. Ms. Shantilal indicated that she did not have the information regarding promotions and that she will follow up with their Human Resources section at Hydro One. In terms of training facilities, she indicated that she will put together a list of training facilities and forward that to Ms.[redacted] for distribution.

Regional Councilor [redacted] asked if Hydro One had any Métis employed in the First Nation and Métis Relations. She noted that Hydro One leadership recognized the territory of the Mississaugas of New Credit but did not recognize that this was also the territory of the Metis. She stated that the Aboriginal awareness training they were providing needed to specifically recognize the Métis, as well as the First Nations. She made the point that if they were building a relationship, Hydro One needed to recognize the perspectives of the Métis of that particular territory. She stated that MNO Employment and Training (MNO-ET) was obtaining funding to help them develop their training/awareness programs and that MNO-ET staff should be part of this discussion. She added that when Hydro One went into a particular region they need to realize that it was not only what could you give the Métis but they also had something to offer. Ms. Shantilal thanked the Regional Councilor for her comments and recognized that this meeting was also on the Métis homeland and that Hydro One recognized the need to be more inclusive. She further stated that this was a relationship building meeting and they appreciated these comments.

[redacted] suggested that Hydro One be mindful that most Métis communities do not have a land base and that eligibility for PowerPlay projects should be open to Metis communities; most eligibility requirements are not inclusive to Métis communities. Ms. Shantilal indicated that, when designing or renewing their programs, they would keep this in mind. Mr. Pugliese further stated that there was a lot of programs that were under review and that Hydro One would be acting on the feedback provided.

[redacted] stated that Union Gas had goal for First Nations, Inuit and Métis recruitment and Hydro One should have a goal if they did not have this in place already. Mr. Pugliese responded that Hydro One will establish a goal and they will be tracking it.

President [redacted] asked about the updating of the Aboriginal awareness training modules, and if, once completed, the Hydro One staff will be retrained on newly updated information and the response was in the affirmative.

[redacted] reiterated some of the things that have been mentioned to potentially increase employment targets such as posting jobs on the MNO website, involve the MNO-ET in discussions involving scholarships, among others. Ms. [redacted] also stated that the MNO did a lot of training and they could also assist Hydro One in this regard. She indicated that the MNO had been working with Hydro One on procurement issues such as hosting an event for Métis businesses to learn more about procurement opportunities that might exist.

In closing, Ms. Shantilal thanked all participants for their feedback and for the offer to help Hydro One with the Aboriginal awareness training and looked forward to more discussion on that.

PROCUREMENT – OVERVIEW OF HYDRO ONE ABORIGINAL PROCUREMENT PROCEDURE

Rob Berardi, A/VP, Shared Services, Hydro One, provided an overview of his presentation entitled “Aboriginal Procurement: Doing Business with Hydro One”. Mr. Berardi opened his presentation by thanking everyone for attending this session and also introduced Kyla Thistle, Contract Officer, Supply Chair, Hydro One, as his co-presenter. He provided a review of current Hydro One procurement procedures. He also stated that they could attend MNO regional meetings to discuss how to navigate the Hydro One system on procurement.

[redacted] asked if Hydro One identified a certain percentage of money aside for First Nation, Métis and Inuit procurement. Mr. Berardi responded that Hydro One did not put a specific percentage aside right now but they could look at doing that. Hydro One did about $15M per annum in Aboriginal procurement right now and they wanted to increase that by 20% each year.

Mr. Berardi explained that Aboriginal participation was preferred and they had information on their external website and competition was limited to qualified aboriginal business. Some contracts could be directly awarded to qualified Aboriginal business. Hydro One could do things differently than when they were a crown corporation.

Regional Councilor [redacted] made the point that a lot of the focus was on supply and purchasing but what about when they were decommissioning assets. Mr. Berardi responded that Hydro One bought things but they also bought services. In terms of decommissioning assets, a supplier could review the asset and then provide the services required for that.

Regional Councilor [redacted] noted that a lot of the issues around Union positions and contract work. He explained that many Métis businesses were small businesses and did not involve unions. Mr. Berardi indicated that it was a difficult question as labour relations have jurisdictions in certain areas such as construction zones or transmission stations. He acknowledged that Hydro One and MNO needed to have those discussions and that Hydro One was open to that. Regional Councilor [redacted] indicated that Union Gas had a stipulation that if they are going to work there, the reserve could provide their own non-union workers. Mr. Berardi stated that those were issues for discussion with labour relations but that there are a lot of services that were non-unionized and these contracts could be filled by Métis businesses.

Mr. Berardi continued his presentation by provided information on the types of materials and services purchased, including heavy-duty equipment, road construction, aggregate and concrete, etc. He explained that there were six steps to award contracts. He suggested that they might want to focus on getting businesses registered and then look what was available. He stated that they could come to the regions to show business owners and others how to get registered and go from there.

[redacted] asked if Hydro One purchased food services. Mr. Berardi responded in the affirmative; Métis food services companies could register and Hydro One procurement could direct the Hydro One staff to use that. This area was a good opportunity.

Mr. Berardi continued stating that the bid system was an online registration and admittedly it was somewhat cumbersome. It was suggested that it needed to be clearer or more support was needed to be able to navigate it.

[redacted] asked how many First Nation and Métis businesses were registered with Hydro One procurement. Mr. Berardi stated there are about 180 to 200 business registered that were First Nation or Metis. He looked forward to looking at ways to increase this number and raise the profile of their system. Ms. Thistle pointed out that they did not have to be an Aboriginal business to register; they could be a First Nation or Métis individual who could provide a service.

CLOSING REMARKS

Ferio Pugliese thanked all participants for their feedback and the candid conversation. He emphasized that that was what this day was designed for and expressed the intention to get out to Métis communities, as Hydro One recognized the regional diversity that existed. He also stated that Hydro One would take MNO up on the offer in regards to the training program. He also encouraged all participants to contact Hydro One if there were any questions resulting from this session. He also stated that they recognized that electricity in Ontario was a complex environment and they were open to working with the MNO and Métis citizens to support them with information and advocacy.

[redacted] stated that, on behalf of MNO, expressed appreciation to all the Métis community representatives for their participation and also thanked Hydro One for providing this information. She stated that this was a relationship building exercise and was not a consultation. She also indicated that participants will be receiving meetings notes and photos from this meeting.

Senator [redacted] closed the meeting with a prayer.

Indigenous Relations – Executive Summary

January 2018

Chief of Ontario Provincial Engagement Session

Hydro One will host its second First Nations Engagement Session on February 21, 2018 at Casino Rama. The purpose of the engagement session is to strengthen our relationships with the 88 First Nation communities we serve, listen to key energy transmission and distribution related issues and concerns they may have and together find solutions moving forward.

Hydro One had a very open and constructive dialog last year that allowed us to learn from each other and at that time we reaffirmed our commitment to continue advancing our relationship with First Nation communities. Many Chiefs expressed frustration at the pace of activity when dealing with Hydro One in the past. We assured them that Hydro One's management team places an enormous importance on First Nations and told them they can expect to see swift action going forward. Appendix A attached hereto highlights the issues raised at last year's engagement session along with the progress made by Hydro One on these matters.

This year the engagement session will focus on: Customer Service; Procurement & Business Partnerships; Employment and Training; and Transmission and Distribution Planning & Reliability Performance.

Treaty #3 Regional Engagement Sessions

Hydro One hosted three engagement sessions on Treaty #3 Territory in Q4 of 2017. Host communities included Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation, and Couchiching First Nation. Of the 25 First Nation communities located in Treaty #3, Indigenous Relations staff met with 15 communities.

The Hydro One team reinforced working relationships between Treaty #3 First Nation communities and Hydro One; shared information on Hydro One's initiatives benefiting First Nation communities; and discussed challenges and opportunities in moving forward. Hydro One provided additional information on procurement and customer service, including the new First Nations Delivery Credit and employment and training. Common issues and concerns related to: three phase power to support infrastructure development, growth of the communities, and consideration for the new First Nations Delivery Credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

A long term strategy needs to be considered on matters related to power quality/reliability in these communities, and their interest in converting from single phase to three phase power to support community energy plans and infrastructure development.

November 2017

Engagement Sessions

Hydro One has hosted and participated in several engagement sessions throughout the year. A summary of issues rose at these engagement sessions, along with results and progress achieved to-date, is provided below.

Top Five Issues February to September 2017 [1]		Results and Progress Achieved
 Affordability	• Communities feel disproportionately impacted by high electricity costs and that delivery charges are higher than consumption both at the individual costumer level and band level.	• Implemented Ontario Fair Hydro Plan reducing bills by as much as 40 to 50%. • Implemented Get Local Initiative reducing arrears. • Implemented First Nations Conservation program reducing energy consumptions and indirectly bills. • Preparing to roll-out the Affordability Fund.
 Reliability	• Communities are impacted by several lengthy power outages, resulting in insufficient electricity supply to serve businesses. • Existing power loads becoming an impediment to implementing community growth plans.	• Increased capital investments replacing aging assets and reducing outages. • Leveraged technology (Distance-to-Fault) to monitor unplanned outages. • Reduced planned outages by bundling renewal work where applicable. • Targeted tree trimming.
 Liability and Access	• Outdated access rights/permits with insufficient compensation, or the lack thereof, for transmission and distribution assets on and off reserve land. • Improper notification protocols for planned and non-planned disconnection related work.	• Progressed with negotiations to settle outstanding real estate agreements. • Initiated discussions to develop an Indigenous Integration Plan with Real Estate which will include strategies and plans to seek certainty on access rights. • Initiated discussions to develop an Indigenous Integration Plan with Provincial Lines and Forestry which will include communication

[1] Chiefs of Ontario First Nations Feb. 9 & 10; Métis Nation of Ontario May 13; Grand Council of Treaty 3 Fort Frances May 18; Anishinabek Nation August 17; Treaty 3 Wabigoon Lake Ojibway Nation September 12.

		protocols.
Partnership	• First Nation communities seek an increase in procurement, investment, ownership opportunities, and other business partnerships.	• Increased procurement opportunities. • Developed set-aside strategy for an RFP. • Progressed with negotiations to reach equity partnership agreement on Tx project (Niagara Reinforcement Project)
Employment	• First Nation communities are interested in more employment opportunities and training.	• Increased employment with new permanent hires. • Participated in career fairs and workshops promoting employment and training.

Chippewas of Rama First Nation

Hydro One held an information session at the Chippewas of Rama First Nation for the Anishinabek Nation on Agust 17, 2017. The goal and objectives were to: reinforce working relationships between Anishinabek Nation First Nation communities and Hydro One; share information on Hydro One's initiatives benefiting First Nation communities; and to discuss challenges and opportunities in moving forward. 30 Anishinabek Nation representatives attended the session.

Treaty #3 Regional Engagement Sessions

Hydro One participated in a Treaty #3 Regional Engagement Session on September 12, 2017 in Wabigoon Lake Ojibway Nation which was attended by members of Wabigoon Lake Ojibway Nation and Eagle Lake First Nation Chief and Council. Additional Dryden region communities invitees included: Lac des Mille Lacs First Nation, Lac Seul First Nation and Wabauskang First Nation. In total 7 First Nation representatives attended the session.

The goal and objectives were to: reinforce working relationships between Treaty #3 First Nation communities and Hydro One; share information on Hydro One's initiatives benefiting First Nation communities; and discuss challenges and opportunities in moving forward. Hydro One presented information on Indigenous Procurement, Customer Service including the new Delivery Charge Credit and Employment and Training. Common issues and concerns related to: 3 phase power to support infrastructure development and growth of the communities, and consideration for the new delivery charge credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

It was agreed that Hydro One's Indigenous Relations team would follow up on all action items in a timely manner. Plans are moving forward to host two more engagement session in the Treaty #3 territory with First Nations in the Kenora and Fort Frances areas. The next session will be in Kenora on November 22 and 23 and the host community is Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation – 11 First Nation communities have been invited. The second session will be in Fort Frances on November 29 and 30 and the host community is Couchiching First Nation – 8 First Nations communities have been invited.

Chiefs of Ontario First Nations

As a follow-up to a commitment made at the February 9 and 10, 2017 engagement session, Hydro One is planning a second annual gathering with the Chiefs of Ontario First Nations on February 21, 2018 at Casino Rama. The purpose of this gathering is to share progress made on most common issues raised at the February 2017 session and to discuss plans to resolve outstanding common issues. The most common issues raised at the February 2017 session were: community visits and outreach; outstanding real estate agreements; customer service programs; increasing Indigenous employment, procurement, partnerships; disconnections; establish emergency and community protocols; and address tax exemptions for First Nations customers living off-reserve.

May 2017

On February 9th and 10th, 2017 the HONI's Board Committee Members participated in an engagement session with First Nation Chiefs in Ontario. All First Nation Chiefs from communities served by HONI, 88 in total, and the Ontario First Nations Regional Organizations were invited to attend the engagement session with the HONI's Board Members, President and CEO and numerous Senior Executive.

The purpose and objective of the engagement session were to hear the Chiefs' thoughts and goals to achieve meaningful progress and build a new vision for HONI's and First Nation communities' collective futures. The Métis Nation of Ontario communities was also invited to a similar session which will be held in May 2017. In addition, the engagement session was a great opportunity to share HONI's thinking and solicit feedback on the application for Distribution

Rates and the distribution system plan that HONI's was preparing for submission to the Ontario Energy Board.

HONI held an engagement session in February 2017 with the First Nation of Ontario communities and the Ontario First Nations Regional Organizations. The purpose of the engagement sessions was to discuss with First Nation communities HONI's distribution rate filling with the OEB. The OEB rate filling document covers the following elements:

- Customer Focus: Services are provided in a manner that responds to identified customer preferences.
- Operational Effectiveness: Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.
- Public Policy Responsiveness: Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).
- Financial Performance: Financial viability is maintained; and savings from operational effectiveness are sustainable.

Where issues do fall within HONI's authority, jurisdiction, and mandate and there are no existing responsive initiatives, HONI will work in collaboration with affected communities to explore, define, and prioritize additional strategies and processes to effectively address these concerns.

Where there are existing initiatives, HONI will continue to work to make meaningful progress in addressing these concerns and consider new initiatives that may assist HONI in this effort. The development of such strategies and processes with First Nations and Métis communities will proceed on the basis of the following principles: action oriented, collaborative, transparent, cost effective and efficient.

Appendix A

Follow-Ups to Chiefs of Ontario First Nations' February 9 & 10, 2017 Engagement Session

	STATEMENT	COMMITMENT	FOLLOW-UP
1.	Mr. Schmidt lists three (3) things he is hopeful will come out of this session: 1. To listen and learn; 2. Provide some education on who is responsible for what, what we each do, how can we as a company can to advocate for you and your community; and, 3. Commit to action. The hope is to move this conversation to an outcome (educate/advocate/action).	Committed to action.	See below
2.	Mr. Schmidt suggests that the feedback that they get from the engagement sessions will go into their upcoming distribution rates submission to the OEB. The information will be collected as part of the application and the First Nations participants' voices will be heard there.	Committed to include FNs feedback into OEB submission.	Included FNs feed-back see Hydro One Networks' Distribution Rate Application (EB-2017-0049) to the OEB Exhibit A Tab 4 Schedule 2 - First Nations and Métis Strategy
3.	Hydro One has met with many First Nations over the last 8 years, including over 200 community visits. Mr. Schmidt suggested that communities interested in inviting Hydro One to visit, attendees should introduce themselves to Ms. Cameron and she will get a team out there.	Committed to community visits when invited.	Completed over 10 new community relationship building visits/outreach since February 2017.
4.	Hydro One is committed to making a change as demonstrated by offering additional regional outreach on procurement, by participating in First Nations employment, training and career fairs and through the First Nations Conservation Program.	Committed to change through additional outreach.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
5.	Mr. Schmidt noted that it is important for Hydro One to hear from the participants and focus on things that can be changed. He committed to listen, but also committed to meeting again in the future to work on some of the things we want to accomplish together. It will take bold action by all of us to effect change.	Committed to meet again.	Completed the following regional engagement sessions: Grand Council of Treaty 3 May 2017; Anishinabek Nation August 2017 and Fall/Winter 2017 hosted three engagement sessions in Treaty #3 Territory - Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles First Nation), and Couchiching First Nation.
6.	Mr. Schmidt shared that he cannot speak to what has happened in the past, but going forward, the focus is on getting people connected rather than disconnected. He also committed to dealing with the issue of cut-offs himself, along with Hydro One legal counsel. The time frames will be addressed, but in general there is no gain for anyone by cutting people off. The larger issue is that we need the cost of power to be reasonable.	Committed to deal with issue of cut-offs.	Extended the Winter Relief Program until June 2017. Reinforced our service level commitment for new connections within five business days with a $75 guarantee.
7.	Mr. Schmidt stated that he agreed with Councillor White, that Hydro One needed to be reasonable and to rethink previous behaviours that were practiced. He notes that there are a lot of attitudes to change	Committed to rethink behaviours and change attitude throughout the	Implemented an internal Leadership Learning Program on Indigenous Relations (On Line & In Class) with over

	throughout the organization and hopes to do better.	organizations.	125 leaders. Conducted 5 Indigenous Cultural Awareness Employees Workshops (Who's Who in the Electricity Sector & Supply Chain).
8.	Chief Patricia Faries said there are power lines going through her land that are intrusive. She expected a response on how her community would be engaged and compensated. Mr. Schmidt introduced Jamie Scarlett and Gary Schneider who can sit and meet with communities to work through their issues. Jamie Scarlett, Hydro One, provided his email address (Jscarlett@hydroone.com) in order to set up future conversations.	Committed to meet with communities to work through real estate issues.	Hydro One Real Estate sent an email to Chief Fairies on September 27, 2017 with no reply yet. Also Hydro One delivered to the Moose Cree First Nation community its Home Assistance Program in August 2017 including support for internal community liaison capacity.
9.	On the question of how do we keep the costs down, Hydro One intends to have a customer presence in local offices; the customer bill was redesigned because customers need to understand the bills; Hydro One has reinforced the commitment to service and of responding in a timely manner.	Committed to reinforce customer service and to respond in a timely manner.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
10.	Mr. Schneider shared that he works on procurement as well as land matters. When it comes to the issue of land he has heard the frustration in the room and agrees that agreements with First Nations need to move forward.	Committed to move forward on real estate agreements.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
11.	Mr. Lister introduced himself as a new member of the Hydro One team and shared his commitment to changing the way they do business. He stated that he intended to listen and welcomed the opportunity to dialogue.	Committed to changing customer service.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
12.	Mr. Pugliese said they committed to visiting First Nations communities, reconnect those who are disconnected, and waive the fees. He asked that the participants let them know which of their community members need this assistance.	Committed to visit communities, reconnect those who are disconnected, and waive the fees.	Followed up with a number of communities e.g., Cat Lake, Pic Mobert and Six Nations
13.	Mr. Lister indicated that they had solutions and ideas to give to the Minister. Many of the short-term solutions that are needed in the communities can be acted on immediately. Hydro One is willing to visit communities that they have not yet visited. For people having difficulty with payments, there can be new payment plans set up.	Committed to visit communities to set up new payment plans.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
14.	Mr. Pugliese noted that Hydro One has launched "Get Local" and written letters to all customers. They are in the process of re-establishing regional or community business offices. They are currently building plans to reinstate regional/community offices to resolve customer issues. In addition, Hydro One is putting a great deal more emphasis on Indigenous Affairs and building more of a strategy around that builds on the good work of Mr. Cameron. This engagement session is the beginning of how Hydro One wants to move forward in doing business. They want to go to the community and regional level on a regular basis.	Committed to meet at community and regional levels on a regular basis.	Completed the following regional engagement sessions: Grand Council of Treaty 3 May 2017; Anishinabek Nation August 2017 and Fall/Winter 2017 hosted three engagement sessions in Treaty #3 Territory - Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles First Nation), and Couchiching First Nation.

15.	In response, Mr. Hubert notes that forums such as this are intended to drive change. He also committed to finding out about the Ontario Energy Board process when it comes to the discussions that the OEB held on the First Nations Rate.	Committed to find out what were OEB discussions held on the FNs rate.	See Report to the Minister Options for an Appropriate Rate Assistance Program for On-Reserve First Nations Electricity Consumers December 29, 2016.
16.	Mr. Hubert explained that there is a delivery charge in both, but the majority of the delivery charge is for distribution. Mr. Hubert referred to his PowerPoint [Slide 6] and noted that electricity makes up the majority of the charge. He also committed to provide both hard and electronic copies of the presentation to the attendees.	Committed to provide both hard and electronic copies of Mr. Hubert's presentation.	Presentations and session reports provided to all participants – see https://www.hydroone.com/about/indigenous-relations/first-nations-engagement-sessions
17.	Chief Brian Perrault recounts an incident last spring where there was a Hydro One crew in his community clearing trees around the lines. The crew came right into his yard where he had 5 trees. Instead of trimming the trees, they cut them all down. The Chief's wife's grandfather planted those trees and he felt like he should have been spoken to about it before they were cut. Mr. Penstone said that Hydro One has not trimmed in a long time. There are OEB standards related to dying and diseased trees. However, Mr. Penstone felt that he could not comment any further because he did not know about the specific situation. In addition, he committed to following up.	Committed to follow-up on Chief Perrault's tree cutting issue.	Couchiching First Nation Chief Perrault talked to Ferio when he was up in the area in May and Ferio asked the Chief to send the pictures to him. In late July Chief said he still hadn't sent the pictures to Ferio. IRD followed up in late Fall and met with Chief Perrault at his house to take the photos. Internal follow-ups undertaken.
18.	Mr. Kiraly mentioned that related to emergency planning, there are some relationships with communities around that, but he recognized that there is certainly not enough of that going on. He continued that they are open to any protocol that the Chiefs feel is most appropriate, for example, Hydro One workers stopping at the band office to let the leadership know what is going on. Mr. Kiraly concluded by saying that many of the items that Chief White-Eye mentioned were possible to achieve.	Commit to discuss emergency planning including protocol with communities.	Engaged with Provincial Lines and Forestry to develop an Indigenous Relations Integration Plan which will include communication protocols with FN communities.
19.	Mr. Pugliese on Longer term issues: There is a need to address longer term issues including outstanding agreements around access, rights, land use, assets on the land. There have been fruitful agreements in the past and Hydro One will continue to work on agreements with First Nations.	Commit to address outstanding real estate agreements.	Continued discussion and negotiations on the 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
20.	Mr. Scarlett noted that the executive team members see working with First Nations as an overlapping mandate across their areas of focus. He noted that they understand it is critical to deal with costs and rates and Hydro One needs help from the government on that. Senior management understands how acute the issue is for First Nations. Regarding land use and resources, the team learned about how long negotiations have gone on and how this has been unacceptable for First Nations. They do not want these kinds of delays to continue. In order to achieve this, he encouraged direct, open and energized conversations. He encouraged a principled and fact-based method of moving forward. Thirdly, he noted the need to move forward on partnerships and co-ventures and working with First Nations more in the area of procurement.	Committed to open up discussions on real estate agreements and move forward on partnerships, co-ventures and procurement.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements. Signed MOUs with 2 First Nations which contemplates equity ownership on a Tx line. Increased Indigenous Procurement with total spends of $24.06M (surpassed 2017 target of $19.8M by 27%). Delivered 5 Indigenous Interactive Procurement Workshops with both Indigenous and non-Indigenous

			businesses.
21.	Mr. Pugliese noted that he wants to be back here celebrating success in one year. The comments will be shared with board members. He concluded by noting that the meeting will end but the conversation will not. He encouraged participants to reach out to Hydro One if there is something you would like to add, and Hydro One will be happy to come to your communities for similar meeting. Thank you.	Committed to meet in one year and to community visits when invited.	Letter sent on October 30 inviting Ontario Chiefs to the second annual gathering on February 21, 2018 in Rama. Completed over 10 new community relationship building visits/outreach since February 2017.
22.	He admitted that the new team at Hydro One recognizes that things had happened in the past when it came to First Nations land and communities. While they cannot change what happened in the past, the new Hydro One team is making a commitment to work differently, in partnership with First Nations. He asked the attendees to judge the new team on their actions. He noted that in a year from now, or sooner, Hydro One will be able to share insights and progress on closing out past grievances, in helping community members with bills, and making movement on affordability.	Committed to work in partnerships with communities and to share progress on closing out past grievances, helping customers with bills and making movement on affordability.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements. Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions. Implemented First Nations Delivery Credit under Fair Hydro Plan.
23.	Related to improving Hydro One's responsiveness, Mr. Pugliese noted that they have heard First Nations speak about empty promises from the past. The new team at Hydro One will improve on this performance.	Committed to improve performance on following up on commitments made.	See all follow-ups above and below and letter sent on October 30, 2017 inviting Ontario Chiefs to the second annual gathering on February 21, 2018.
24.	Mr. Pugliese asked participants to let Hydro One know what they wanted in terms of training programs for communities. They are willing to go to communities to work on individual bills, explain the bills, and get clients on plans; however, these activities take many visits. Another option is training people within communities to host these meetings and provide this service within the community. These programs are just getting started, but Hydro One will continue to work with communities in this area.	Committed to visit communities to work on bills and plans and offered community training to support customer services.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions and offered community liaison capacity to 6 First Nations.
25.	Chief R. Donald Maracle noted that some councils loan monies to community members for bills in arrears. He asked what Hydro One could do for communities in this situation. Some people have had to go to high interest rate companies to borrow, which is a hard cycle for people to get out of. Mr. Pugliese responded that people would generally have to rely on social service agencies and that Hydro One does not have a policy on this issue, but can potentially look into it. In addition, he noted that they spoke with the Premier on affordability funding. The current program qualifiers are stringent but perhaps Hydro One can use the surpluses in cases such as this. The Chief noted that in smaller communities there are no service agencies and have to depend on the band council. Mr. Martinez noted that when they come to the community in March they will bring the United Way with them. Community members can apply for relief from the United Way. He has done this with First Nations communities before. Mr. Pugliese noted that this issue has come up before and is something that they want to look at. They are looking to support an adjudication process in order to address it. This is a potential suggestion for action going forward.	Committed to consider alternate affordability support program.	Currently implementing the new Affordability Fund which can help improve home's energy efficiency with free energy-saving upgrades, which can lower home energy use and electricity bill. Also advocating on delivery credit for First Nations owned buildings.
26.	Mr. Pugliese commented that Hydro One cannot address poverty in a general sense. It is a very broad,	Committed to address poverty and	Implemented Get Local Initiative reducing arrears by

	complex social issue. However, Hydro One can focus on the bills as part of their own social responsibility. Also related to community social services, perhaps Hydro One can support those through Hydro One's community giving program.	social issues through bills and sponsorship and grant programs.	visiting 19 communities and holding 1282 one-on-one sessions and approved over $3.5M in Indigenous sponsorships over last 10 years. In 2017 alone reviewed and approved a total of $745,750 in grant/sponsorship proposals supporting healthy Indigenous communities.
27.	Mr. Pugliese responded that Hydro One supports Councillor Archibald's position on the delivery charge; however, it is not Hydro One that controls that. Regarding Hydro One staff entering the community, Hydro One has heard this concern previously and believes that their staff must respect the community protocols. They should first visit the band office. Finally, with respect to the disconnection and whether there could be load limiters, Mr. Pugliese noted that there are resources on this that Hydro One is willing to share through their outreach activities.	Committed to respect community protocols when entering communities and to offer load limiters to address disconnections.	Engaged with Provincial Lines and Forestry to develop an Indigenous Relations Integration Plan which will include communication protocols with FN communities.
28.	Mr. Pugliese responded that he is sure there must be information on the revenues generated through those agreements. He noted that he and the Chief Legal Officer had been going through all of the agreements to identify what had gone wrong in the past and where there are fixable issues. Hydro One wants to re-evaluate all of those agreements and resolve outstand issues. Regarding submersibles, Mr. Pugliese noted that they are happy to sit and meet to have a discussion. In addition, the Chief Operations Officer would be presenting later and would be better suited for that discussion.	Committed to address outstanding real estate agreements and to discuss submersible lines.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
29.	Mr. Schmidt shared that Hydro One met with the majority of the First Nations communities that they serve, which included over 200 community visits. He noted that they are looking to expand community visits and welcomed the participants to let Hydro One know if they were interested in a community visit. He appreciated the goals and aspirations, as well as the needs of First Nations rights-holders and landowners, in terms of business development and community relationships.	Committed to expand community visits when invited.	Completed over 10 new community relationship building visits/outreach since February 2017.
30.	Chief Sayers asked if Hydro One would be willing to honour the point of sales tax exemption for all Indigenous people in Ontario no matter where they live. This was his formal request. The Chief's second point is on working for mutual benefit; he wondered how working together would look, and what would be the benefits, in general. Mr. Schmidt asked his staff member, Ms. Cameron to make a note on the issue of taxes. He stated that given the complexity of the tax system there would have to do some analysis on that. He committed to going back to Chief Sayers on that topic. Ms. Cameron sought to clarify Chief Sayers' statement; that the tax can be removed for customers on reserve once Hydro One receives a status number, but she believes what Chief Sayers is referring to is eliminating the taxes even for those First Nations who are not living on reserve. Chief Sayers: The Chief clarified that at the time the agreement was made, there was no differentiation between on-reserve or off-reserve. Ms. Cameron said that Hydro One would go back to their tax group to discuss as well as talk to the province. She noted that they had been audited several times by the Canadian Revenue Agency related to tax collection. She also noted	Committed to follow-up on tax exemption for customer residing off reserve.	No follow-up made.

	that, on a personal level, she agreed with Chief Sayers.		
31.	Chief McLeod shared that his band council had to issue 220 cheques to Elders to assist them in paying their hydro bills. That is $88,000 in one month. He notes that it is not just the financial burden; they view it as insulting and immoral. The Chief shared that there are two major lines running through his First Nation, and yet leadership has to explain why citizens who are struggling are getting delivery charges. He noted that his community members are outraged, particularly because Hydro One does not pay anything to the community for the lines running through their territory and then Hydro One turns around and charges outrageous rates. They view this as money that is owed to them, and they need a conversation about that. Mr. Schmidt noted that Hydro One staff needed to meet with Chief McLeod on this issue and wondered if the contract lapsed or was ever renewed? He committed to reviewing these agreements. Ms. Cameron suggested that Mr. Gary Schneider, Hydro One, can talk with the Chief on this issue.	Committed to address real estate agreement.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
32.	Councillor Archibald noted that when it comes to projects in their area, the First Nations should be contacted for employment. He noted the case of Otter Rapids specifically. They had sent permits for the band council to review, and when the band signed off, the contractor said “oh sorry, no jobs.” Councillor Archibald’s second point is related to disconnections. He does not believe that Hydro One staffs are aware of the new policies around working with people one-on-one to avoid disconnections because in his community they just cut people off. He noted that he sent a letter to Mr. Schmidt’s office and received no response. Mr. Schmidt assured Councillor Archibald that he responds to every note that comes into his office. He asked that he resend a copy and he will respond. In terms of employment, Mr. Schmidt stated that he could not agree more and wants First Nations employees to participate in projects. He committed to putting people in touch with Ms. Judy McKellar, Executive Vice President, Chief Human Resources Officer. In regards to disconnection, Mr. Schmidt asked participants to let Hydro One know of anyone living without power. Hydro One wants to get them connected. If any community has people headed in that direction, Mr. Schmidt asked them to let Hydro One know and they will try and find a way to manage. In addition, if your community would like Hydro One to make a community visit, just ask.	Committed to connect with HR on project employment opportunities to connect customers and to community visits when requested.	Participated in 8 Indigenous employment outreach sessions in 2017 reaching approximately 200 Indigenous student participants.
33.	Chief Maracle reminded the room that land was never surrendered to the Crown, yet the Crown gave letters of patent to others for some of his reserve land. Some members of his community live on that land part time. He wondered if their bills could be tax exempt, as their rights are being infringed on. Mr. Schmidt offered to talk to legal counsel on the issue and help investigate the situation. He noted that, if necessary, Hydro One could advocate the community’s position with the provincial and federal governments as well. Mr. Penstone suggested that what the Chief was describing was a federal jurisdictional issue. The land was not surrendered. Secondly, the status of First Nations as it relates to tax is also a federal issue that would have to be determined by the Canadian Revenue Agency.	Committed to discuss with legal and governments to address tax exemptions for non-reserve lands.	No follow-up made.
34.	Chief Pamajewon began by describing an issue his community had related to a road. The province was	Committed to consider, with the	Initiated internal discussions IRD & Provincial Lines.

	involved, and the First Nations took them to task on that. Cottagers were pushing the province to build a road west of his community. The community knew that those lands were still theirs. All the blasting required to build that road affected the aquifer and wells dried up. The community had to fight INAC on that issue. His community drilled the well and successfully negotiated with the Ministry of Transportation. Now the community has a water station, which requires power to operate. The Chief noted that there are many power outages and as a result, the community had to purchase generators for the well and the facility. There are a number of outstanding expenses related to power failures. Mr. Schmidt commented that Hydro One formed a group specifically to deal with water station outages. On occasion they have supplied the province with generators and fuel in the past. Mr. Schmidt suggested that perhaps Hydro One could support First Nations in this way, with the support of the province and the OEB.	support of the province and OEB, offering generators to communities for water stations during outages.	
35.	Chief Paul Eshkakogan would like to see a table developed to move this work around contracts and employment/training forward. As an example of his frustration, the Chief noted that even on the issue of vegetation management, they could not get anyone on the project because of a union issue. He reiterated that they need jobs in his community to pay the bills. The Chief expressed a desire to come to an agreement to continue the dialogue related to unlocking job and contracting opportunities for First Nations. Mr. Penstone agreed with the Chief and noted that there have been instances where First Nations communities provided material and services for projects. Mr. Penstone directed the comment to his colleagues in procurement. A Hydro One representative agreed with the Chief and suggested that they do a workshop with the community and their businesses in order to participate in the Hydro One sourcing events. He also commented that he supported the idea of a table for dialogue and is considering what that would look like from a strategic perspective. He agreed that they needed to start those discussions.	Committed to offer a procurement workshop and to consider a dialogue table on employment/training/procurement.	Procurement workshops offered when requested. No follow-up made on dialogue table. Increased Indigenous Procurement with total spends of $24.06M (surpassed 2017 target of $19.8M by 27%). Delivered 5 Indigenous Interactive Procurement Workshops with both Indigenous and non-Indigenous businesses.

<u>Summary of Commitments</u>

Common Commitment Themes	%
Community Visits & Outreach	25%
Real Estate Agreements	18%
Customer Services	18%
Employment, Procurement, Partnerships	7%
Cut-offs	7%
Emergency & Community Protocols	5%
Tax Exemptions Off Reserve	5%

Feed-Back to OEB	5%
Tree Cutting	2%
Provide Copy of Presentation	2%
Performance on Follow-Ups	2%
Change Internal Behaviour & Attitude	2%
Sponsorships	2%

Hydro One Métis Nation of Ontario Engagement Session- May 13th

Responses to follow-up questions

A participant noted that Hydro One had cut down a number of trees in the North Bay area to avoid interruptions due to weather but they had not cut down the right trees.

For us to be able to follow up internally we need to know (i) the location of the "wrong trees"- and what are the trees that should have been cut down but weren't? Additionally, it may be helpful to know the timeframe (when/how long ago) did this occur. Hydro One Forestry followed up directly with the meeting guests to address this comment

If there is oil spill from a Hydro one transformer on residential property, how do we clean it up?

Hydro One dispatches a crew to investigate all potential spills that are reported by customers/property owners. The responding crew is trained to do initial containment, complete small cleanups and report internally. A 24X7 On-Call Environment Contact is notified and an Emergency Response Contractor and an Environment & Health Technician are mobilized to complete the larger cleanups, excavating impacted areas. All spills are reported internally in our EHSM data base (Internal reporting system) and external reporting is completed as legally required.

Do we notify the home owner regarding the same and provide them with details as to how we cleaned it up?

Yes, the customer/property owner is informed and the clean-up method is often discussed. Depending on the type of material spilt (pre-1985 electrical insulating oil) the property owner is sent a follow up letter with oil analysis and potentially soil confirmation analysis.

Can potential home buyer access information regarding such oil spills that may have occurred at a residential property they are considering buying?

Hydro One does not provide access to this information. We treat these types of queries on a case-by-case basis. Potential purchasers should be asking the seller for this information, the seller should disclose. For this reason, we provide letters & lab analysis reports on potential PCB spills. Purchasers can also go down the road of a Freedom of Information request to the Ministry Of Environment and Climate Change.

What about Species at Risk legislation when it comes to cutting trees down to protect the lines?

Hydro One takes its responsibility with respect to Species at Risk (SAR) very seriously. During the planning of vegetation management on rights-of-way or line maintenance projects, Hydro One works with the Ministry of Natural Resources and Forestry (MNRF) and other stakeholders to identify if there are any SAR in the work location. If a SAR is identified, we will try to avoid any effects on the species. This may be able to be done with the scheduling of work to a time of year when the work will not affect the species, avoiding accessing the area that the species is in or changing vegetation management technique. If it is not possible to avoid the impact, we will develop a plan to minimize or mitigate the effect. The plan will be registered with MNRF as required in Ontario Regulation 242/08 under the Ontario Endangered Species Act (OESA).

On larger projects, we work with MNRF, stakeholders and often hire a consultant to identify SAR or SAR habitat in the vicinity of the project. This information is taken into account during the design of the project. We will apply for any permits required under the OESA. We will also comply with the Federal Species at Risk Act, where it applies. For larger projects, we usually develop a restoration plan for post construction with biodiversity in mind depending on the surrounding land uses. Currently, we are working with OMAFRA, MNRF, the David Suzuki Foundation and other stakeholders on the creation of pollinator habitat on some of the transmission Right of Way and station sites.

We have developed materials to train our staff in the identification of Species at Risk and the processes to follow if they are identified in the work area. We have several biologists that are employed by Hydro One that advise on SAR mitigation and habitat creation.

What are wood poles treated with and could this negatively affect vegetation in the area?

The types of chemical used to treat our wood poles depend on the type of wood. Hydro One uses Copper Chromated Arsenate (CCA) for treating Cedar poles and CCA-PEG

(Polyethylene glycol) for treating Pine poles. Hydro One's poles go through a treatment fixation process which affixes the treatment to the wood and limits any leaching. There may be some minor surface leaching, but this will typically take place while the poles are still in storage, prior to installation. There are no concerns with our treatment negatively affecting vegetation in the area of where the pole is installed.

Does Hydro One have an employment coordinator that could assist them with the process of applying to apprenticeships?

All applications must be submitted online via the www.PWU.ca website. For any issues, the Power Workers Union (PWU) can be reached at: Toll Free: 1-800-958-8798. They can also email Aboriginal.Recruitment@HydroOne.com

What are some of the interview techniques used by Hydro One?

Hydro One uses a number of interview techniques – behavioural questions, scenario based questions, presentations where candidates are asked to develop and deliver a presentation on a particular topic as well as some testing for things like Excel. As part of the interview process we also conduct psychometric assessments where candidates are asked to answer a number of questions on their computer.

How does Hydro One hire for promotions- are efforts focused on internal promotions?

Hydro One must abide by the collective agreement with regards to vacancies or promotions. For all management positions, Hydro One has a robust development and performance plan that all employees are asked to participate in.

Where are Hydro One's training facilities located?

Hydro One has training facilities in Kleinberg and Orangeville.

Anwaatin Inc. Interrogatory # 2

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1-01-01 Section 3.5

Interrogatory:

Preamble:

In 2015, the North American Electric Reliability Corporation (NERC) Essential Reliability Services Task Force (ERSTF) recognized that the power system resource mix is changing from the use of larger synchronous sources to the use of a more diverse fleet of smaller sized resources with varying characteristics[1]. NERC defines distributed energy resources (DERs) as any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electricity System (BES). DERs can include distributed generation (DG), behind the meter generation (BTMG), energy storage facilities (EFS), DER aggregation (DERA - aggregating multiple DG, BTMG, or ES devices at different points of interconnection on the distribution system), micro-grids, cogeneration, and emergency, stand-by and back-up generation (BUG).

Energy consumer demand for DERs is growing as customers are able to access or benefit from DERs in response to unexpected utility power outages, planned rolling blackouts, power quality

[1] North American Electric Reliability Corporation (NERC), 2017 – Distributed Energy Resources, February 2017, online: < http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_ Resources_ Report.pdf >.

problems, and increases in power costs. With the availability and increasing cost-effectiveness of DERs, distribution customers are seeking to take advantage of technologies for power generation, storage and back-up supply.

a) Please describe how Hydro One consulted First Nations on increasing Hydro One capital investments in DERs to improve system reliability for First Nation customers in grid-connected communities and what resulted from these consultation efforts.
b) Please describe how Hydro One's consolidated framework to guide its First Nations and Métis relations and engagement is inclusive of DERs and responsive to the growth in the application of DERs.

c) Given Hydro One's findings that some First Nation communities indicate that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve, please describe and provide any and all of Hydro One's plans, timing and cost to:

   i. effectively address reliability on all reserves;
   ii. facilitate businesses on reserves; and
   iii. integrate DERs into areas of Northern Ontario that experience high frequency and duration of power outages to improve system reliability.

d) Given: (i) Hydro One's process of developing a consolidated framework to guide First Nations and Métis relations and engagement across all lines of business, and (ii) Hydro One's expansion into US markets, please provide a detailed listing of each and all Hydro One efforts to obtain, consider and integrate information, experience and knowledge from tribal utilities in the U.S. and U.S. electricity distributors that serve Native American tribes into Hydro One's First Nations and Métis Strategy, Framework and Guidance. Please highlight any and all information and initiatives relating to DERs.

e) Please describe how Hydro One's investment planning process considers appropriate planning criteria for the increasing scale of demand for DERs, especially for rural and First Nation customers seeking relief from reliability issues and increasing costs.

f) Please describe how Hydro One is accommodating the demand for DERs connected to the distribution system in terms of making its distribution network and customer services "DER-friendly", especially in areas where system reliability is a significant issue, such as northern Ontario.

Response:

a) See part c) of Exhibit I-6-Anwaatin-1.

b) One of the objectives of Hydro One's First Nations and Métis Strategy is to develop opportunities to collaborate with First Nations and Métis communities in Ontario through the development of business, technical, knowledge and advocacy partnerships and this is inclusive of exploring with First Nation communities potential distributed energy resource projects. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects. These partnerships could include providing technical expertise/support to Indigenous communities in the development/ implementation of energy plans, purchasing services or goods from Indigenous businesses where they can provide goods and services to Hydro One, and developing energy literacy.

c)

i. Hydro One has several capital and OM&A expenditures reflected in this Application that, in part, fund work that will improve reliability for First Nations communities. The expenditures that are expected to have the largest positive impact for First Nations communities are listed below and explained in the following evidentiary references:

- Worst Performing Feeders investment described in section 3.8 of the DSP (ISD SS-06); and
- Hydro One's new vegetation management strategy, explained in Exhibit Q-01-01 section 2.1 "Change in Vegetation Management Strategy".

ii. In addition to the reliability improvement expenditures discussed above, Hydro One has several capital expenditures proposed reflected in this Application that, in part, fund work that enables additional capacity on assets that directly supply First Nations communities and facilitate new connections. The expenditures that are expected to impact supply for First Nations communities are listed below and explained in the corresponding evidence references found in section 3.8 of the DSP:

- Life Cycle Optimization & Operational Efficiency Projects, ISD SR-13;
- System Upgrades Driven by Load Growth, ISD SS-02; and
- Demand Investments, SS-04.

iii. Hydro One is examining opportunities to implement DER technologies to improve reliability of supply for all its customers, including those that live in First Nations communities. This work is funded as part of Development OM&A explained in section 3.4 of Exhibit C1, Tab 1, Schedule 3 under the heading "Microgrids" on page 8 of 12.

d)

i. Hydro One is enhancing reliability for customers, including First Nation communities, particularly for electrical loads supplied by single circuit distribution lines. In Northern Ontario, the distribution lines traverse long distances and generally carry small electrical loads. Any forced outage of a single circuit ("radial") line would result in some (or all of the load) supplied by the line to be interrupted.

ii. Hydro One has work focused on the distribution line feeders, distribution stations and distribution operating facilities to enhance distribution system reliability. Examples of specific actions include, but are not limited to, installing reclosers, circuit switches, in line switches, fault locators, surge arrestors, focused vegetation management, as well as ensuring major equipment replacements under the sustainment work programs as outlined in the DSP.

iii. Hydro One is examining opportunities and DER technologies for potential installation, including First Nations communities to enhance reliability, particularly on single circuit lines.

Before such solutions are implemented, determining technical and economic feasibility is crucial. Hydro One has partnered with EPRI (Electric Power Research Institute) to undertake a study for a Northern Ontario single circuit line, to assess the technical and financial suitability of installing DER technologies to address reliability concerns. This joint work with EPRI is still underway, and Hydro One has an application filed with the Government of Canada's NRCan to seek funding from NRCan's Smart Grid Program. Following successful completion of this project, the DER technologies could be applied at various parts in Northern Ontario to address reliability problems where technically and economically feasible.

The transaction for the purchase of Avista by Hydro One has not yet closed. Hydro One has not undertaken any efforts to obtain, consider and integrate information, experience and knowledge from tribal utilities nor from any electricity distributor in the United States that serves Native American tribes.

e) Hydro One’s investment planning process ensures that when assets are replaced as part of renewal programs, distribution automation assets are deployed as replacements. This enables the advanced functionalities of the distribution management system that can result in improved reliability and efficiencies. In addition, the Demand Response for Operations project (see section 3.8 of the DSP, ISD SS-07) will help optimize system use and apply to eligible communities.

f) Please see response to e) above. Based on “lessons” from the need to rapidly connect DER technologies (mainly solar and wind) generation under the previous FIT and microFIT (Feed in-tariff) programs, Hydro One has “standardized” the DER connections process to Hydro One’s grid. This process allows for technically consistent and timely completion of customer requests for DER connection.

Hydro One also participates in joint research with utilities and organizations, such as EPRI and CEATI, to keep a watching brief on emerging technologies and better ways to enable DER technology grid connections. Further, Hydro One strives to keep aware and, as appropriate, participate in developing or updating technical standards (e.g. IEEE, CSA) that would more effectively enable DER connections to the grid.

Anwaatin Inc. Interrogatory # 3

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1-01-01 Section 3.5

Interrogatory:

a) Please list any and all First Nation communities that are concerned about historical, present and future compensation (or the lack thereof), for Hydro One assets on reserve land and/or within traditional territories and treaty lands.

b) Please list and describe in detail any and all measures that Hydro One has taken with respect to DERs and business partnerships with DERs as a means of accommodating First Nation communities that are concerned about historical, present and future compensation (or the lack thereof), for Hydro One assets on reserve land and/or within traditional territories and treaty lands.

c) Please list any and all DER assets, projects or initiatives that Hydro One has:
   i. in its rural distribution networks in non-First Nation communities in Ontario;
   ii. in its urban distribution networks in Ontario; and
   iii. in its rural distribution networks in Washington, Oregon, Idaho, Alaska and Montana.

d) Please provide all power quality and reliability metrics and results for the Hydro One distribution system for:
   i. all Ontario;
   ii. Northern Ontario; and
   iii. The Anwaatin communities.

e) Please provide a complete list, and the cost, of any and all distribution system upgrades in:
   i. Northern Ontario; and
   ii. the Anwaatin communities.

f) Please describe how Hydro One plans to adopt and/or scale any and all DER projects, or other lesson from Avista related to Indigenous communities, in rural Ontario and for First Nation communities.

g) Has Hydro One sought information from other North American regulated electricity distributers on their applications and experiences where DERs may be solutions for customers are dealing with rural power quality problems, and increases in power costs? Please describe any and all applications and experiences that Hydro One is investigating further or seeking to apply to its distribution networks. Please provide any information that Hydro One has received from other entities regarding same.

Response:

a) Hydro One is currently in the process of addressing reserve access issues for assets with the following First Nations communities:

Table 1

First Nation	Issue	Progress
1. Algonquins of Pikwakanagan	Determining proper form of "Sub-transmission" (not transmission) agreement and proper approach to administer payments to locatees.	Confirming with INAC/OEFC who approves agreement.
2. Wabaseemoong	Outdated MOU, Payment In Lieu of Taxes (PIL) Agreement and Annual Land Rental Payment.	Legal drafting of the final agreements pending agreement on fundamental terms of agreement.
3. Nipissing	Requiring new memorandum of understanding (MOU), PIL and distribution and transmission agreements under a *First Nation Land*	Legal drafting of the final agreements.

	Management Act regime.	
4. Serpent River	Need to secure new MOU, outdated PIL Agreement and Annual Land Rental Payment.	Legal drafting of the final agreements.
5. Munsee-Delaware	Need to complete appraisal for the beneficiary/estate trustee of a deceased Certificate of Possession (CP) Holder's interest under the *Indian Act* re: transmission overhanging rights occupation.	Ongoing discussions with the deceased CP Holder's beneficiary and lawyer to complete appraisal and to accept new permit.
6. Chippewas of the Thames	Unclear transmission occupation rights, outdated value of PIL Agreement and Annual Land Payment and outstanding locatees' interests impacted by the transmission overhanging rights occupation.	Finalizing budget discussions to negotiate a Framework Agreement encompassing real estate matters.

The First Nations listed in Table 1 are the key communities who have raised concerns about historic, present and future compensation for Hydro One assets on reserve and within their respective traditional territories. Similar concerns related to compensation have been raised as a general concerns throughout various engagement sessions over the last few years. Hydro One does not have a list of specific First Nations that have raised this concern as Hydro One does not provide compensation for distribution assets on reserve, since the distribution facilities serve the First Nation communities, as it does for all of Hydro One's customers in Ontario.

b) There are no active distributed energy resource (DER) projects related to Indigenous communities, however, it is expected that DER lessons and opportunities are transferable to all communities.

c) The requested list follows below.

i. DER assets in rural distribution networks in non-First Nation communities in Ontario:

- Demand Response for Operations Project
  - Please see Investment Summary Document SS-07 Advanced Distribution System "ADS" for details.
- Flywheel Energy Storage System - Tillsonburg, Ontario
  - 500 kWh / 5 MW flywheel
- Springbank Project - Woodstock, Ontario
  - Acquired as part of Woodstock Hydro acquisition
  - 10 kW photovoltaic system

ii. DER assets in urban distribution networks in Ontario:

- Whites Lane Microgrid Project - Woodstock, Ontario
  - Acquired as part of Woodstock Hydro acquisition
  - 3.5 kW photovoltaic system (net metered)

- 20 kW photovoltaic system
- 20 kWh/ 10 kW lead acid battery
- 20 kWh/ 8 kW lithium ion battery

iii. Hydro One Networks does not own any DER facilities in Washington, Oregon, Idaho, Alaska or Montana. Avista is a stand-alone utility, operated independently from Hydro One.

d) Reliability metrics are constant across Ontario. Reliability is measured in terms of duration of outages (SAIDI) and frequency of outages (SAIFI). Please see section 1.4.2.1 of the DSP (Exhibit B1, Tab 1, Schedule 1) for a more detailed explanation. The reliability results for Ontario, Northern Ontario, and Anwaatin Communities are provided below:

- 2012-2016 Average SAIDI, including LOS and FM
  - Hydro One (All Ontario): 14.9
  - Hydro One Northern Ontario:15.7
  - Anwaatin Communities: 15.3

- 2012-2016 Average SAIFI, including LOS and FM
  - Hydro One (All Ontario): 3.8
  - Hydro One Northern Ontario: 4.7
  - Anwaatin Communities: 4.2

Hydro Ones does not have any power quality metrics. However, Hydro One follows the standards and guidelines for power quality as per Hydro One's Conditions of Service (see section 2.3.2 Power Quality for details). Hydro One addresses power quality customer concerns when they arise.

e) Hydro One has the following distribution system upgrades in Northern Ontario. None of these upgrades are in the Anwaatin communities.

Planned Year	Distribution System Upgrade	Cost ($M)	DSP Reference
2018	Margach DS F3 - SD 3676 Voltage Conversion	1.4	ISD SR-13 (LC-3)
2018	Devlin DS F1 3 Phase Upgrade	1.0	ISD SS-02 (LG-2)
2018	Sowerby DS Station Refurbishment	2.5	ISD SR-06
2019	Crilly DS Replacement and Transformer Upgrade	6.7	ISD SS-02 (LG-20)
2019	Margach DS F3 Voltage Conversion - SW 676	1.4	ISD SS-02 (LG-23)
2019	Whitedog DS Station Refurbishment	2.5	ISD SR-06
2019	Birch island DS Station Refurbishment	2.5	ISD SR-06
2019	Dack DS Station Refurbishment	2.5	ISD SR-06
2019	Kirkland Lake Voltage Conversion - Part 2	2.0	ISD SS-02 (LG-21)
2020	Devlin DS Rebuild and Voltage Conversion	4.0	ISD SR-13 (LC-20)
2020	Kenora DS Station Refurbishment	2.6	ISD SR-06
2020	Cobalt DS Station Refurbishment	2.6	ISD SR-06
2020	Blind River Voltage Conversion	1.0	ISD SR-13 (LC-21)
2020	Kirkland Lake Voltage Conversion - Part 3	2.8	ISD SS-02 (LG-33)
2021	Emo DS Station Refurbishment	2.8	ISD SR-06
2021	Wolsey Lake DS Station Refurbishment	2.8	ISD SR-06
2021	Town of Elliot Lake Station Upgrades	2.2	ISD SR-13 (LC-28)
2021	Fairbanks Lake Line Upgrade	2.5	ISD SS-02 (LG-40)
2021	Lively DS F2 SW 142 Upgrade Black Lake Road	1.4	ISD SS-02 (LG-42)
2022	Schreiber Winnipeg DS Station Refurbishment	2.9	ISD SR-06
2022	Sleeman DS Rebuild and Voltage Conversion	4.2	ISD SR-13 (LC-37)
2022	Rutherglen DS Station Refurbishment	2.9	ISD SR-06
2018-2019	Coniston Voltage Conversion	3.9	ISD SR-13 (LC-8)
2018-2019	Hanmer TS Feeder Development	4.9	ISD SR-13 (LC-10)
2018-2019	Kirkland Lake Voltage Conversion - Part 1	4.8	ISD SS-02 (LG-13)
2020-2021	Wikwemikong DS & Line Work	6.5	ISD SS-02 (LG-38)
2021-2022	Manitoulin TS - Add Third 44 kV Feeder	4.6	ISD SS-02 (LG-46)
2018	Worst Performing Feeder Modernization - Murillo DS F1	0.3	ISD SS-06
2018	Worst Performing Feeder Modernization - Murillo DS F3	0.5	ISD SS-06

Planned Year	Distribution System Upgrade	Cost ($M)	DSP Reference
2018	Worst Performing Feeder Modernization - Port Arthur TS M6	0.4	ISD SS-06
2018	Worst Performing Feeder Modernization - Trout Creek DS F1	0.1	ISD SS-06
2018	Worst Performing Feeder Modernization - Manitoulin TS M25	0.6	ISD SS-06
2018	Worst Performing Feeder Modernization - Manitoulin TS M26	0.1	ISD SS-06
2018	Worst Performing Feeder Modernization - Trout Lake TS M7	0.3	ISD SS-06
2018	Worst Performing Feeder Modernization - Shiningtree DS F1	0.3	ISD SS-06
2018	Worst Performing Feeder Modernization - Clarabelle TS M8	0.4	ISD SS-06
2018	Worst Performing Feeder Modernization - Martindale M5	0.3	ISD SS-06

f) Hydro One has developed positive relationships with Indigenous communities and customers across the Province of Ontario. Helping communities realize their aspirations is central to Hydro One's integrated Indigenous Relations approach with respect to partnership, integration, and leadership. Please see part c) of Exhibit I-6-Anwaatin-1.

As part of the work highlighted in section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD SS-07 (Advanced Distribution Management System), Hydro One is building a Distributed Energy Resource Management System as part of its Demand Response for Operations project. One of the objectives of the project is to use DERs to accommodate connection requests using existing assets. Hydro One is also seeking federal government funding to pilot the use of DERs to improve reliability in rural Ontario and First Nation communities.

g) In addition to the work discussed in Exhibit I-6-Anwaatin-2, Hydro One has partnered with utility research organizations including EPRI (Electric Power Research Institute) and CEATI (Centre for Energy Advancement through Technological Innovation) to undertake research with other utilities on issues including, reliability, power quality, cost concerns and other issues related to application of DERs. Through these research organizations' working groups, Hydro One gains insight into DER practices of other utilities across North America including understanding DER grid integration challenges from the technical and economic feasibility view point.

Hydro One also chairs a committee of large Ontario Local Distribution Companies specifically for the purpose of sharing experience related to the integration of DERs.

Anwaatin Inc. Interrogatory # 4

Issue:
Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
A-04-02 Page: 3

Interrogatory:
a) Please provide the presentation, all notes, memos, reports and related documents from Hydro One's First Nations engagement session, including any and all reports to the Board of Directors.

b) Please provide any and all communications between Hydro One Transmission and Hydro One Distribution relating to:

(i) the needs of Indigenous communities;
(ii) reliability in Indigenous communities; and
(iii)any other matter relating to Indigenous communities.

Response:
Please see Exhibit I-6-Anwaatin-1 and Attachment 1 to this response. Communications between Hydro One Transmission and Hydro One Distribution are not relevant to issues 6 or 23 as it does not provide information that the OEB may require to determine whether Hydro One Distribution's First Nation and Metis Strategy sufficiently addresses the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service or the adequacy of Hydro One Distribution's customer consultations generally.

Witness: CHUM Derek

January 2018

Chief of Ontario Provincial Engagement Session

Hydro One will host its second First Nations Engagement Session on February 21, 2018 at Casino Rama. The purpose of the engagement session is to strengthen our relationships with the 88 First Nation communities we serve, listen to key energy transmission and distribution related issues and concerns they may have and together find solutions moving forward.

Hydro One had a very open and constructive dialog last year that allowed us to learn from each other and at that time we reaffirmed our commitment to continue advancing our relationship with First Nation communities. Many Chiefs expressed frustration at the pace of activity when dealing with Hydro One in the past. We assured them that Hydro One's management team places an enormous importance on First Nations and told them they can expect to see swift action going forward. Appendix A attached hereto highlights the issues raised at last year's engagement session along with the progress made by Hydro One on these matters.

This year the engagement session will focus on: Customer Service; Procurement & Business Partnerships; Employment and Training; and Transmission and Distribution Planning & Reliability Performance.

Treaty #3 Regional Engagement Sessions

Hydro One hosted three engagement sessions on Treaty #3 Territory in Q4 of 2017. Host communities included Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation, and Couchiching First Nation. Of the 25 First Nation communities located in Treaty #3, Indigenous Relations staff met with 15 communities.

The Hydro One team reinforced working relationships between Treaty #3 First Nation communities and Hydro One; shared information on Hydro One's initiatives benefiting First Nation communities; and discussed challenges and opportunities in moving forward. Hydro One provided additional information on procurement and customer service, including the new First Nations Delivery Credit and employment and training. Common issues and concerns related to: three phase power to support infrastructure development, growth of the communities, and consideration for the new First Nations Delivery Credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

A long term strategy needs to be considered on matters related to power quality/reliability in these communities, and their interest in converting from single phase to three phase power to support community energy plans and infrastructure development.

November 2017

Engagement Sessions

Hydro One has hosted and participated in several engagement sessions throughout the year. A summary of issues rose at these engagement sessions, along with results and progress achieved to-date, is provided below.

Top Five Issues February to September 2017 [1]		Results and Progress Achieved
Affordability	• Communities feel disproportionately impacted by high electricity costs and that delivery charges are higher than consumption both at the individual costumer level and band level.	• Implemented Ontario Fair Hydro Plan reducing bills by as much as 40 to 50%. • Implemented Get Local Initiative reducing arrears. • Implemented First Nations Conservation program reducing energy consumptions and indirectly bills. • Preparing to roll-out the Affordability Fund.
Reliability	• Communities are impacted by several lengthy power outages, resulting in insufficient electricity supply to serve businesses. • Existing power loads becoming an impediment to implementing community growth plans.	• Increased capital investments replacing aging assets and reducing outages. • Leveraged technology (Distance-to-Fault) to monitor unplanned outages. • Reduced planned outages by bundling renewal work where applicable. • Targeted tree trimming.
Liability and Access	• Outdated access rights/permits with insufficient compensation, or the lack thereof, for transmission and distribution assets on and off reserve land. • Improper notification protocols for planned and non-planned disconnection related work.	• Progressed with negotiations to settle outstanding real estate agreements. • Initiated discussions to develop an Indigenous Integration Plan with Real Estate which will include strategies and plans to seek certainty on access rights. • Initiated discussions to develop an Indigenous Integration Plan with Provincial Lines and Forestry which will include communication protocols.
Partnership	• First Nation communities seek an increase in procurement, investment, ownership opportunities, and other business partnerships.	• Increased procurement opportunities. • Developed set-aside strategy for an RFP. • Progressed with negotiations to reach equity partnership agreement on Tx project (Niagara Reinforcement Project)
Employment	• First Nation communities are interested in more employment opportunities and training.	• Increased employment with new permanent hires. • Participated in career fairs and workshops promoting employment and training.

Chippewas of Rama First Nation

Hydro One held an information session at the Chippewas of Rama First Nation for the Anishinabek Nation on Agust 17, 2017. The goal and objectives were to: reinforce working relationships between Anishinabek Nation First Nation communities and Hydro One; share information on Hydro One's initiatives benefiting First Nation communities; and to discuss challenges and opportunities in moving forward. 30 Anishinabek Nation representatives attended the session.

[1] Chiefs of Ontario First Nations Feb. 9 & 10; Métis Nation of Ontario May 13; Grand Council of Treaty 3 Fort Frances May 18; Anishinabek Nation August 17; Treaty 3 Wabigoon Lake Ojibway Nation September 12.

Treaty #3 Regional Engagement Sessions

Hydro One participated in a Treaty #3 Regional Engagement Session on September 12, 2017 in Wabigoon Lake Ojibway Nation which was attended by members of Wabigoon Lake Ojibway Nation and Eagle Lake First Nation Chief and Council. Additional Dryden region communities invitees included: Lac des Mille Lacs First Nation, Lac Seul First Nation and Wabauskang First Nation. In total 7 First Nation representatives attended the session.

The goal and objectives were to: reinforce working relationships between Treaty #3 First Nation communities and Hydro One; share information on Hydro One's initiatives benefiting First Nation communities; and discuss challenges and opportunities in moving forward. Hydro One presented information on Indigenous Procurement, Customer Service including the new Delivery Charge Credit and Employment and Training. Common issues and concerns related to: 3 phase power to support infrastructure development and growth of the communities, and consideration for the new delivery charge credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

It was agreed that Hydro One's Indigenous Relations team would follow up on all action items in a timely manner. Plans are moving forward to host two more engagement session in the Treaty #3 territory with First Nations in the Kenora and Fort Frances areas. The next session will be in Kenora on November 22 and 23 and the host community is Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation – 11 First Nation communities have been invited. The second session will be in Fort Frances on November 29 and 30 and the host community is Couchiching First Nation – 8 First Nations communities have been invited.

Chiefs of Ontario First Nations

As a follow-up to a commitment made at the February 9 and 10, 2017 engagement session, Hydro One is planning a second annual gathering with the Chiefs of Ontario First Nations on February 21, 2018 at Casino Rama. The purpose of this gathering is to share progress made on most common issues raised at the February 2017 session and to discuss plans to resolve outstanding common issues. The most common issues raised at the February 2017 session were: community visits and outreach; outstanding real estate agreements; customer service programs; increasing Indigenous employment, procurement, partnerships; disconnections; establish emergency and community protocols; and address tax exemptions for First Nations customers living off-reserve.

May 2017

On February 9th and 10th, 2017 the HONI's Board Committee Members participated in an engagement session with First Nation Chiefs in Ontario. All First Nation Chiefs from communities served by HONI, 88 in total, and the Ontario First Nations Regional Organizations were invited to attend the engagement session with the HONI's Board Members, President and CEO and numerous Senior Executive.

The purpose and objective of the engagement session were to hear the Chiefs' thoughts and goals to achieve meaningful progress and build a new vision for HONI's and First Nation communities' collective futures. The Métis Nation of Ontario communities was also invited to a similar session which will be held in May 2017. In addition, the engagement session was a great opportunity to share HONI's thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that HONI's was preparing for submission to the Ontario Energy Board.

HONI held an engagement session in February 2017 with the First Nation of Ontario communities and the Ontario First Nations Regional Organizations. The purpose of the engagement sessions was to discuss with First Nation communities HONI's distribution rate filling with the OEB. The OEB rate filling document covers the following elements:

- Customer Focus: Services are provided in a manner that responds to identified customer preferences.
- Operational Effectiveness: Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.
- Public Policy Responsiveness: Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).
- Financial Performance: Financial viability is maintained; and savings from operational effectiveness are sustainable.

Where issues do fall within HONI's authority, jurisdiction, and mandate and there are no existing responsive initiatives, HONI will work in collaboration with affected communities to explore, define, and prioritize additional strategies and processes to effectively address these concerns.

Where there are existing initiatives, HONI will continue to work to make meaningful progress in addressing these concerns and consider new initiatives that may assist HONI in this effort. The development of such strategies and processes with First Nations and Métis communities will proceed on the basis of the following principles: action oriented, collaborative, transparent, cost effective and efficient.

Anwaatin Inc. Interrogatory # 5

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

A-04-02 Page: 5

Interrogatory:

a) Please identify precisely which of the issues identified Hydro One considers to be beyond Hydro One's authority, jurisdiction and mandate and the rationale for that determination in chart format.

Response:

a) The chart below details provides further information on issues that have been raised by Indigenous communities that are beyond Hydro One's authority, jurisdiction, and mandate as a publicly-traded utility and require or depend upon broader action by the provincial and federal governments.

Issue	Definition	Rationale
Paying for high delivery rates	Will Hydro One address the delivery rates from a Treaty Rights basis which could include entering into resource revenue sharing agreements?	• Hydro One is not responsible for generating electricity in Ontario. It distributes electricity to customers that is generated by Ontario Power Generation and other third-parties. • Like all electricity distributors in Ontario, Hydro One is regulated by the Ontario Energy Board (OEB). As such, Hydro One's delivery rates are based on the cost-to-serve model and are approved by the OEB through a fair, transparent and participatory process. • Any discussion with respect to revenue sharing relating to electricity generated from resources in Ontario should be held between First Nations, the Crown, and other third parties involved in such electricity generation.

Issue	Definition	Rationale
Paying for electricity losses	Why First Nations must pay for electricity lost during transmission, and before it reaches my home or business?	• All electricity customers in Ontario pay for this as it is how rates are designed. • Electricity line losses are an unavoidable part of the electricity distribution business. When electricity is transmitted over long distances and passes through wires and transformers, it is normal for a small amount of power to be used or lost as heat. For example, if we deliver 1,000 kWh to you, we must purchase a small amount more than what you use. To determine the amount of electricity we need to buy for you, we use a calculation called an "adjustment factor."
Compensating for distribution assets	Will Hydro One provide compensation for its distribution assets on reserve? If not why not?	• Hydro One does not provide compensation for distribution assets on reserve, since the distribution facilities serve the First Nation communities, as it does for all of our customers in Ontario. • The only instance where this varies is when a distribution line passes through a First Nation community and out the other side with no "off ramps" to serve the community (often referred to as a sub-transmission line). These are treated like transmission occupations. • Hydro One also does not provide compensation for occupations on road allowances.
Addressing historical grievances	Will Hydro One agree to a process to address historical grievances related to distribution assets on reserve?	• The Ministry of Energy Ontario has agreed to and commenced past grievance process related to energy matters.

Issue	Definition	Rationale
Acquiring proper access rights for assets on reserve	Why are Hydro One distribution assets located on reserve lands without proper rights or with questionable rights acquired many decades ago without proper First Nation's consultation and consent?	• The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued. • Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that Hydro One will manage them until it has obtained permits to complete the title transfer. • To occupy Reserves with transmission assets, Hydro One must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, Hydro One must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights.

Anwaatin Inc. Interrogatory # 6

Issue:

Issue 6: Does Hydro One’s First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One’s distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

A-04-02 Page: 6

> *"Under this new service model that was launched in September 2016, representatives from Hydro One's Customer Service team visit First Nations communities around the province to meet with Chiefs and Councils, conduct community information sessions, and have one-on-one sessions with individual customers. During these sessions, Hydro One helps customers by providing information about conservation programs and resources that may assist low-income customers and ensure that qualifying customers are aware of and accessing the Province of Ontario's Electricity Support Program."*

Interrogatory:

a) Please provide copies of:
    (i) any and all materials provided to customers during these sessions; and
    (ii) any and all notes, memos, reports, and documents resulting from these sessions.

Response:

Please find attached the key document provided to customers during First Nations community visits. Hydro One visited 29 First Nations communities and met one-on-one with over 1,700 unique customers. Notes, memos, reports, and documents resulting from these one-on-one customer sessions were specifically related to individual customer accounts and as such are considered by nature confidential.

Witness: CHUM Derek

Need help?

For more information visit **www.HydroOne.com/KeepingYourAccountCurrent**

In addition to Hydro One's payment arrangements and Budget Billing Plan, you may qualify for financial assistance programs, including the following:

Resource	Details
Ontario Electricity Support Program (OESP)	Monthly on-bill credits, based on income Apply at **www.ontarioelectricitysupport.ca** or call 1 855 831-8151
Low-Income Energy-Assistance Program (LEAP)	Emergency grants, based on income. Contact the United Way at **www.unitedwayGSC.ca** or call 1 855 487-5327 to learn more.
Home Assistance Program (HAP)	Free energy-efficient upgrades, based on income. Contact GreenSaver at 1 855 591-0877 or visit **www.HydroOne.com/HAP**
Community Services	Your municipality may provide additional income support. Call 2-1-1 or visit **www.211ontario.ca/topic/income-support**
Vital Services By-law	Protects tenants if the landlord has not paid the utility bill. File form T2 at **www.sjto.gov.on.ca/ltb/help-for-tenants**

Suggested Actions to take

1		○
2		○
3		○
4		○

Anwaatin Inc. Interrogatory # 7

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Reference:

A-04-02 Page: 6

> "*In the past year, Hydro One has also made submissions to the Ontario Energy Board, at the request of the Minister of Energy, to provide advice on options for an appropriate electricity rate (or rate assistance) for on-reserve First Nations electricity customers.*"

Interrogatory:

a) Please provide a copy of each and all such submissions or other communications.

Response:

a) Please see Attachment 1.

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BY COURIER

December 2, 2016

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

Dear Ms. Walli,

EB-2016-0274 – Options for an Appropriate Rate Assistance Program for On-Reserve First Nations Electricity Consumers

On June 27, 2016, the Minister of Energy Minister asked the Ontario Energy Board to examine options for developing a First Nations Rate and to report back by January 1, 2017. Hydro One Networks Inc. and Hydro One Remote Communities Inc. are pleased to provide comments on the presentation made by Ontario Energy Board Staff at a recent meeting on developing a First Nations rate for on-reserve First Nations customers.

This submission consists of the following five sections:

1. Consideration of the Options;
2. Billing System Impacts;
3. Qualification;
4. Funding Mechanism; and
5. Hydro One's on-reserve Customer Service initiatives.

Hydro One appreciates the opportunity to participate in these discussions and to provide comments on this important initiative.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

HYDRO ONE NETWORKS INC. & HYDRO ONE REMOTE COMMUNITIES INC. COMMENTS ON DEVELOPING A FIRST NATIONS RATE FOR ON-RESERVE FIRST NATIONS ELECTRICIY CUSTOMERS

Hydro One Networks Inc. and Hydro One Remote Communities Inc. (in this submission, jointly referred to as "Hydro One") are pleased to provide comments on the presentation made by Ontario Energy Board Staff (Board Staff) at a recent meeting on developing a First Nations rate for on-reserve First Nations customers. Hydro One was an active participant in this meeting, which was held for affected distributors on November 8, 2016.

On June 27, 2016, the Minister of Energy asked the Ontario Energy Board (the Board) to examine options for developing a First Nations Rate and to report back by January 1, 2017. Board Staff has advised that the Board will be guided by the following principles in developing its report for the Minister:

- Maximizing benefits for on-reserve First Nations customers at the lowest cost to other ratepayers;
- Ease of program implementation for First Nations customers and utilities;
- Fairness to all customers; and
- Accountability to First Nations customers by demonstrating how their views and perspectives have informed the Board's report.

This submission consists of the following five sections:

1. Consideration of the Options;
2. Billing System Impacts;
3. Qualification;
4. Funding Mechanism; and
5. Hydro One's on-reserve Customer Service initiatives.

1. CONSIDERATION OF THE OPTIONS

Hydro One is aware that Board Staff has conducted research on potential options and rate impacts and has held engagement sessions with First Nations groups and affected distributors. Based on this research and input from these engagement sessions, Board Staff has indicated that two options are being considered for providing a First Nations Rate:

1. an on-bill credit (percentage or dollar amount) to the Delivery charge; and
2. a total bill reduction (percentage or dollar amount).

It is Hydro One's view that a percentage credit to the Delivery charge (or a credit to the monthly service charge, in the case of Hydro One Remote Communities Inc.) is the most prudent option.

Hydro One believes that a credit to the Delivery charge would be easier to explain to customers because it would relate to a specific line item on their electricity bill. It is anticipated that the bill would also show the Delivery charge prior to application of the credit, and the amount of the credit, to help explain the bill calculation.

It is also Hydro One's view that a percentage credit, rather than a fixed dollar amount, should be implemented, as the Delivery charge varies with consumption. This approach would allow the credit to vary in line with the Delivery charge.

If the decision is made to vary the credit amount or percentage based on the season, Hydro One suggests that the changes should be made at the same time as changes are made for the Regulated Price Plan (RPP), i.e. May 1st and November 1st of each year. This would reduce implementation and administration costs, as it would allow distributors to combine the system modifications and testing for both the RPP changes and the First Nations rate changes.

2. BILLING SYSTEM IMPACTS

There is no material difference in the cost or ease of implementing a credit to the Delivery charge, as opposed to a total bill reduction. Based on preliminary estimates, the approximate one-time cost to implement either option is $1.0 to $1.3 million. Additional program details would be required to refine this estimate.

It is anticipated that either option would take up to 6 months to implement. Sufficient time is required to: define and implement a process for identifying customers who would qualify for the First Nations rate; modify Hydro One's customer information system for the chosen option; test the modifications to ensure accuracy; and develop and implement a plan to communicate the changes to qualifying customers.

It should be noted that Hydro One has initiated a bill redesign project. The timeline for implementing Hydro One's redesigned bill may conflict with the implementation of the First Nations rate. Hydro One is not aware of the anticipated timing for implementing a First Nations rate. However, to implement the First Nations rate by mid-2017, Hydro One would need to know the selected option by mid-January of 2017, although the amount of the credit could be finalized later. This prior knowledge would allow sufficient time for the required changes to be architected before the billing system "freeze" which is required for Hydro One's bill redesign project.

It would be helpful for distributors to be provided more detailed program information as early as possible. Early information, as it becomes available, would allow Hydro One to start planning for and completing the preliminary work required to change customer and billing processes.

Hydro One proposes that a variance account would need to be established to capture the difference between the actual credits that are provided to on-reserve First Nations customers and the amounts collected from all Ontario customers to support the program. This variance account would be disposed of at future rates proceedings.

3. QUALIFICATION

Hydro One believes that qualification for the program should not be administratively cumbersome. To the extent possible, automatic enrollment should occur for customers residing on-reserve who have already provided information to Hydro One on their First Nations status. Partial identification of on-reserve First Nations customers can be achieved within Hydro One's customer information system by combining address information (to confirm that a customer is located on a reserve) and tax exempt status (to confirm that the customer is a First Nations customer).

Hydro One notes that this approach will not capture all on-reserve First Nations customers, as some customers may not have provided Hydro One with their tax exempt status. Processes would need to be put in place to capture the remaining customers who would be entitled to the First Nations rate. This could be accomplished through communications programs and working with Band Councils to encourage qualifying customers to provide Hydro One with their First Nations status.

It is Hydro One's view that, ultimately, the onus should rest with customers to self-identify if they qualify for the First Nations rate. As part of the program communications to customers, it should be made clear that self-identification and qualification for the proposed rate is accomplished by customers providing Hydro One with information on their tax exempt status.

Hydro One further recommends that customer bills would reflect the proposed First Nation rate on a going-forward basis only after they have identified to Hydro One that they qualify for that rate. Hydro One is not supportive of any retroactive application of the First Nations rate, as such an approach would be very difficult to apply and administratively burdensome, and could lead to customer confusion in understanding their bills.

4. FUNDING MECHANISM

Board Staff indicated that a provincial charge is being considered for the funding mechanism to recover program costs. The options for this provincial funding mechanism, as identified by Board Staff, are: use of the current Rural or Remote Rate Protection (RRRP); or a new separate regulatory charge, charged only to those customers who are not recipients of the First Nations rate.

Hydro One believes that the fairest and most expedient way to fund the program is through the RRRP. This will ensure that the cost of the program is shared by all Ontario electricity customers. The RRRP is already in place and could be increased to provide the required funding for the First Nations rate. A new funding mechanism is not recommended, as this would require more time for any necessary government approvals and would increase costs for setting up and administering this new funding mechanism. If a new funding mechanism is adopted, Hydro One recommends that the regulatory charge apply to all customers in Ontario, in a similar manner to how the RRRP charge is applied.

5. HYDRO ONE'S ON-RESERVE CUSTOMER SERVICE INITIATIVES

Board staff shared with Hydro One that Six Nations of the Grand River (Six Nations) is happy with the approach that Hydro One has taken related to customer care on their reserve. Specifically, Hydro One has; initiated contact with Chiefs and Councils to build consensus and approval for the initiative; conducted town hall sessions with local residents for educational purposes related to understanding the bill and conducted one-on-one sessions with local residents to discuss programs such as budget billing and payments plans to address arrears, thereby providing a "one-stop shop" to address all of their needs, including information on low income programs (OESP and LEAP programs). Hydro One is also aware that other First Nations customers would like to see this approach expanded to their communities.

Hydro One is pleased to hear about the positive feedback from Six Nations. Hydro One is expanding this approach to other First Nations communities, and plans to visit other communities to provide similar information to help customers understand and manage their electricity usage and bills.

Hydro One appreciates the opportunity to participate in these discussions and to provide comments on this important initiative.

Building Owners and Managers Association Toronto Interrogatory # 146

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 42: Is the updated executive compensation information filed by Hydro One in the distribution proceeding on December 21, 2017 consistent with the OEB's findings on executive compensation in the EB-2016-0160 Transmission Decision?

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Issue 56: Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?

Issue 17: Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?

Issue 15: Is the proposed Earnings/Sharing mechanism appropriate?

Reference:

A-03-02 Page: 2

Interrogatory:

a) Please explain fully why the proposed revenue cap provides more flexibility than a price cap IR to introduce new rate classes in 2021 to integrate recent acquisitions.

b) Please explain fully why the proposed "revenue cap" would permit the continued transition to a fully-fixed rate for residential customers while a price cap IR would not.

c) ines 27-29 – Please explain, given that the OEB has already decided to eliminate seasonal rates, the point is included.

d) line 30 – Why does the proposed revenue cap provide more flexibility than price capex to meet customer commercial and industrial customer rates if the OEB decides that changes in rate design should be made?

e) p3 - Why would the proposed revenue cap, but not a price cap regime, allow HONI to update its billing determination to reflect estimated charges in its load forecast when it integrated the acquired utilities?

f) p9 – Please explain the derivation of the 2021 revenue requirement outlined at lines 6-8.

g) p10 – Given the design of the CCSA, why would any unit credited to the deferral account not be dead at the end of each year to ratepayers?

h) Capital Factor (General) – Question with the capital factor, is there any cap on the actual level of capital expenditures in a given year, other than the capacity of the utility to finance the additions?

i) p10 – Why is the threshold level for making entries in the proposed CISVA be 98% of the OEB-approved account, rather than the OEB-approved account?

j) How will verifiable productivity gain be determined? What constitutes verification and who will ultimately determine whether a reduction in capital expenditure is due to a productivity gain? Please discuss.

k) p11– What is meant by the reference to "regional planning" as an "event" that would qualify for Z-factor treatment?

l) Please explain why "regional planning" would meet Z-factor criteria.

Response:

a) See Hydro One's response to Exhibit I-7-VECC-3.

b) See response to part (a).

c) A summary of the current status of the elimination of the Seasonal class is provided in pages 2 and 3 of Exhibit G1, Tab 2, Schedule 1.

d) See response to part (a).

e) Under Price Cap IR, distribution rates are adjusted directly by an index each year. The underlying load forecast underpinning those rates remains unchanged therefore, Price Cap does not consider or allow for a change in billing determinants.

f) The incremental rate base and OM&A associated with the Acquired Utilities is detailed in Exhibit A, Tab 7, Schedule 1. The incremental rate base associated with the Acquired Utilities in 2021 is reflected in the rate base on line 1 and the incremental OM&A is shown in line 10 of Table 1 of Exhibit A, Tab 3, Schedule 2.

g) Hydro One does not understand the question.

h) The Revenue Cap Index only provides for funding of the planned level of capital expenditures outlined in Hydro One's Distribution System Plan (Exhibit B1, Tab 1, Schedule 1). Hydro One will not receive revenues during the rate term for any spending above these amounts.

i) See Hydro One's response to Exhibit I-17-EnergyProbe-14.

j) See Hydro One's response to Exhibit I-10-EnergyProbe-11.

k) Regional Planning is referenced as an example of an investment that is government-mandated or otherwise outside of management's control. An investment requirement outside of management's control that would materially impact the operation of Hydro One and was outside of the base upon which rates were based would meet the criteria for Z-factor treatment.

l) See above.

Ontario Sustainable Energy Association Interrogatory # 3

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Reference:

A-04-02 Page: 3

Preamble: "In 2016, Hydro One developed a new First Nations Conservation Program. This program offers on-reserve residents the opportunity to improve the energy efficiency of their homes and manage their energy use more effectively."

Interrogatory:

a) What is Hydro One offering to on-reserve residents as part of the First Nations Conservation Program?

b) Does Hydro One have any past, current or forecasted results on the savings resulting from the First Nations Conservation Program? If so, please provide.

Response:

a) Eligible First Nation customers who participate in the program receive a home assessment and the provision and installation of applicable energy-efficient equipment, at no cost to the customer or the community. This is being offered to the First Nation communities served by Hydro One Networks which were not already served by the IESO's Aboriginal Conservation Program. The assessment evaluates the energy use in the home and determines which measures the customer may be eligible for. Additional information can be found on Hydro One's website:

   https://www.hydroone.com/saving-money-and-energy/residential/first-nations-conservation-program

b) In the first year of the program (2017), Hydro One served 2,100 First Nation customers. 41 additional communities are being targeted for participation between 2018 and 2020. The total forecasted energy savings from the program by 2020 are approximately 10 GWh.

Witness: CHUM Derek

Ontario Sustainable Energy Association Interrogatory # 4

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Reference:

Hydro One Networks Inc. 2018 - 2022 Distribution Rate Application, Community Meeting Report 1. OEB File No. EB-2017-0049

Interrogatory:

a) Did Hydro One's presentation at the community meetings include information about the rate relief for some of Ontario's Indigenous customers? If not, why?

Response:

Hydro One's presentations at the community meetings provided an overview of Hydro One's Distribution Rate Application and the associated impact on the customer's bill after Fair Hydro Plan, which includes the First Nations Delivery Credit.

OEB Staff Interrogatory # 14

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Reference:

Executive Presentation Day Transcript, page 47

Interrogatory:

At this reference, Mr. Pugliese indicated that Hydro One has met with over 1,500 First Nations customers in their communities and has helped decrease customer arrears in those communities by 24 percent year over year.

a) Does Hydro One have a special collections program for customers in the First Nations Communities? If yes, please provide the details of this program and how it differs from the standard program.

b) Does Hydro One forecast further improvement in customer arrears reductions?

Response:

a) Hydro One implemented a "Get Local" First Nations program in 2016, which focuses on meeting with First Nations communities and customers across the province. The initiative was part of a company-wide effort to focus on enhanced customer service and offer customers choice to speak with Hydro One in person and one-on-one, potentially overcoming some language and/or cultural barriers. Hydro One visits numerous communities throughout the year, meeting with customers one-on-one to explain bills, assist with payment plans, and help customers enroll in certain programs (such an the First Nations Delivery Credit, the Low-Income Energy Assistance Program, and the Ontario Electricity Support Program). As a result of these one-on-one sessions, the number of First Nation customers in arrears decreased by 2,100 in 2017.

b) Hydro One will continue to promote the Get Local First Nations program in an effort to help customers who are struggling to remain current.

Witness: MERALI Imran

OEB Staff Interrogatory # 15

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Reference:

A-04-02/C1-01-07 Page 16-17
At this reference, Hydro One summarizes its First Nations and Metis Strategy and lists a number of initiatives and undertakings with First Nations.

Interrogatory:

a) Has Hydro One instituted a specific scorecard that measures its success in its dealings with First Nations on a general level and also with regard to specific initiatives? If so, please provide this scorecard or report.

b) With regard to the new customer service offerings mentioned, please provide a summary of these programs.

Response:

a) Hydro One received Bronze level certification under the Canadian Council for Aboriginal Business (CCAB) Progressive Aboriginal Relations Program (PAR) in August 2017.

   This certification program assesses corporate performance in Aboriginal relations in four areas (leadership actions, employment, business development, and community relationships) and includes an independent verification process that involves gathering information from the Company as well as Indigenous communities that interact with the Company. The certification program validates Hydro One's performance and confirms the Company's commitment, success, and impact to Aboriginal Relations.

   The CCAB describes PAR Bronze companies as follows:

   PAR Bronze companies are distinguishable among thousands of Canadian businesses because they recognize the business case for working with Aboriginal businesses and communities. Their strategic planning recognizes the mutually-beneficial impact of business development with Aboriginal-owned businesses, the value that Aboriginal people bring to the workplace, and the potential of Aboriginal communities. PAR Bronze companies are beginning a journey, developing the goals and action plans that position them to work with the Aboriginal community.

Hydro One will continue to measure its success in these same four areas (leadership actions, employment, business development, and community relationships), using the PAR criteria.

b) Hydro One offers the following programs to help First Nation customers manage their electricity bills:

i. Get Local First Nations – Please refer to Exhibit I-6-Staff -14.

ii. First Nation Conservation Program – The program, which was introduced in 2016, assess a home's energy efficiency and provides energy efficient upgrades.

iii. First Nations Delivery Credit (Fair Hydro Plan) – As of July 1, 2017, First Nation customers residing on reserve and paying for electricity are entitled to a credit equal to the Delivery Charge on their monthly bill.

OEB Staff Interrogatory # 16

Issue:

Issue 6: Does Hydro One’s First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One’s distribution service?

Reference:

A-04-02
In the last Hydro One transmission rate hearing (EB-2016-0160), First Nations concerns were an important part of the proceeding.

Interrogatory:

Has Hydro One changed or amended any of its First Nations and Metis strategies or practices in its distribution business as a result of the EB-2016-0160 experience?

Response:

During the Hydro One transmission rate hearing (EB-2016-0160), there were concerns raised by First Nations with respect to affordability and reliability. Hydro One has undertaken additional work in both of these areas since the transmission rate hearing which respond to these concerns as well as concerns raised in the engagement sessions relating to the Application.

This includes:

- Implementing an outreach plan to ensure all eligible First Nations customers benefit from the First Nations Delivery Credit announced as part of the Ontario Fair Hydro Plan which came into effect on July 1, 2017

- Commencing implementation of the First Nations Conservation Program (FNCP) which is a follow-up program to the Aboriginal Conservation Program and designed to help First Nations customers to decrease their hydro bills by increasing their conservation efforts

- Implementing the Get Local Initiative to help customers by providing information about conservation programs and resources that may assist low-income customers and ensuring that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program.

- Commencing the roll-out of the Affordability Fund to improve First Nations' home energy efficiency by providing free energy-saving upgrades, which can lower home energy use and, correspondingly, a customer's electricity bill over the long term.

- Revising Hydro One's vegetation management policy to increase the frequency of forestry maintenance work on reserve.

For measures that improve reliability, please see part c) i), ii), and iii) in Exhibit I-6-Anwaatin-2.