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Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

July 20, 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-2016-0160 – Hydro One Networks Inc.'s 2017 and 2018 Transmission Cost-of-Service Application – Updated Evidence Filing

Attached are two (2) paper copies of updated exhibits for Hydro One Networks Inc.'s Transmission Cost-of-Service Application, which was filed with the Ontario Energy Board ("OEB") on May 31, 2016.

The evidence has been updated to reflect:

- Decreased pension operating expenses resulting from an updated actuarial valuation report;
- Removal of B2M LP costs that were inadvertently included in the original filing; and
- Lower OEB assessment costs due to an allocation methodology change that was implemented by the OEB.

All changes are numerical in nature, with the exception of the updated actuarial valuation report for the pension plan which is included as a new attachment to Exhibit C1, Tab 4, Schedule 2. The revisions were made as of the date of this letter.

These revisions result in OM&A reductions of $12.7 million in 2017 and $11.0 million in 2018 in comparison to Hydro One's original filing.

A detailed list of the updated evidence is provided below:

Exhibit	Tab	Sch.	Att.	Content
A	2	1		Application
A	3	1		Executive Summary
A	7	2		Hydro One Networks Inc. Transmission Pro Forma Statement of Income Bridge Year (2016) and Test Years (2017 and 2018)
C1	1	1		Cost of Service Summary
C1	2	1		Summary of OM&A Expenditures
C1	3	1		Summary of Common Corporate Costs - OM&A
C1	3	3		Common Corporate Functions and Services and Other OM&A
C1	4	2		Pension Costs
C1	4	2	1	Hydro One Inc. Hydro One Pension Plan: Actuarial Valuation as at December 31, 2015 (June 9, 2016)
C1	6	1		Common Corporate Costs, Cost Allocation Methodology
C1	6	1	1	Review of Allocation of Common Corporate Costs (Transmission) - 2015
C2	1	1		Cost of Service
C2	2	1		Comparison of OM&A Expense by Major Category – Historic, Bridge, and Test Years
E1	1	1		Revenue Requirement
E1	2	1		External Revenues
E2	1	1		Calculation of Revenue Requirement
G1	1	1		Cost Allocation and Rate Pool Revenue Requirement
G1	3	1		Network, Line Connection and Transformation Connection Rate Pools
G2	4	4		OM&A Costs by Functional Category
G2	5	1		Detailed Revenue Requirement by Rate Pool
H1	5	1		Bill Impacts
H2	1	2	1	2017 Ontario Transmission Rate Schedules
H2	1	2	2	2018 Ontario Transmission Rate Schedules
H2	1	2	3	2017-2018 Draft Uniform Transmission Rates and Revenue Disbursement Allocators

An electronic copy of the updated evidence and complete application has been filed using the Board's Regulatory Electronic Submission System and will be posted on the Hydro One website.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				**Administration**
A	1	1		Exhibit List
A	2	1		Application
A	2	1	1	Certification of Evidence
A	3	1		Executive Summary
A	4	1		Compliance with OEB Filing Requirements for Electricity Transmitters
A	4	2		Summary of Board Directives and Undertakings from Previous Proceedings
A	5	1		Corporate Organization Charts
A	5	2		Governance and Control Framework
A	5	2	1	Hydro One Inc. Mandate for the Board of Directors
A	5	2	2	Hydro One Inc. Nominating, Corporate Governance, Public Policy & Regulatory Committee Mandate
A	5	2	3	Hydro One Inc. Audit Committee Mandate
A	5	2	4	Hydro One Inc. Health, Safety, Environment, First Nations and Métis Committee Mandate
A	5	2	5	Hydro One Inc. Human Resources Committee Mandate
A	5	3		Affiliate Service Agreements
A	5	3	1	Agreement between Hydro One Inc., Hydro One Remote Communities Inc., Hydro One Networks Inc. and Hydro One Telecom Inc. (January 1, 2016)
A	5	3	2	Agreement between Hydro One Networks Inc., Hydro One Remote Communities Inc., Hydro One Inc. and Hydro One Telecom Inc. (January 1, 2016)
A	5	3	3	Agreement between Hydro One Telecom Inc. and Hydro One Networks Inc. (January 1, 2015)
A	5	3	4	Agreement between Hydro One Networks Inc. and Hydro One Remote Communities Inc. (January 1, 2016)
A	5	3	5	Agreement between Hydro One Networks Inc., B2M GP Inc., and B2M Limited Partnership by its general partner B2M GP Inc. (December 17, 2014)

APPLICATION

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the Act approving rates for the transmission of electricity.

<u>APPLICATION</u>

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

2. Hydro One hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* for an order or orders approving the revenue requirement, use of certain regulatory accounts and customer rates for the transmission of electricity, to be implemented on January 1, 2017 and for a two-year period ending December 31, 2018.

3. Hydro One seeks approval of a revenue requirement of $1,606 million and $1,687 million for the test years 2017 and 2018, respectively. The applied-for revenue requirements have been developed using a traditional cost-of-service methodology. Recovery of each of these amounts is estimated to increase the total electricity bill for

a medium density R1 (750 kWh) customer by 0.2% in 2017 and 0.3% in 2018 and the total electricity bill for a general service energy (2000 kWh) customer by 0.1% in 2017 and 0.2% in 2018 as compared to 2016 and 2017 levels. This bill impact reflects Hydro One's transmission rates increasing by 3.7% and 5.4% in each of the test years relative to 2016 approved rates and 2017 applied-for rates, respectively. The transmission component of the average total distribution bill is approximately 6.8%. These changes take into account a decreased load forecast over the two year rate period

4. Hydro One also requests that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2017 and 2018, effective January 1st of each year.

5. Hydro One also seeks rate approval for its Export Transmission Service ("ETS") rate. The proposed rate is $1.85/MWh for each of the test years, which was approved by the Board in Hydro One's last transmission revenue requirement application EB-2014-0140.

6. Hydro One seeks approval to continue the following regulatory accounts:
    a) Excess Export Service Revenue;
    b) External Secondary Land Use Revenue;
    c) External Station Maintenance, E&CS Revenue and Other Revenue;
    d) Tax Rate Changes;
    e) Rights Payments;
    f) Pension Cost Differential;
    g) East West Tie Deferral Account – Incumbent Transmitter;
    h) Long-Term Transmission Future Corridor Acquisition and Development Account;

i) North West Bulk Transmission Line Account;
j) Supply to Essex County Transmission Reinforcement (SECTR) Account;
k) External Revenue – Partnership Transmission Projects Account; and
l) In-Service Capital Additions Variance Account.

7. Hydro One seeks approval of regulatory assets with a total credit balance of $130.7 million as at December 31, 2015. Hydro One seeks approval to refund over a twenty-four month period commencing January 1, 2017, regulatory assets with a net credit balance of $95.6 million, reducing the annual revenue requirement.

8. The evidence filed in support of this Application is generally organized in accordance with the Board's new *Filing Requirements for Electricity Transmission Applications* effective February 11, 2016 (the "*Filing Requirements*"). Specifically, the evidence is organized as follows:

Exhibit A:	Administrative Documents
Exhibit B:	Transmission System Plan, Cost Efficiencies/Productivity (including Performance Scorecard) and Total Cost Benchmarking
Exhibit C:	Cost of Service (Operating Costs)
Exhibit D:	Rate Base and Cost of Capital
Exhibit E:	Revenue Requirement and Load Forecast
Exhibit F:	Regulatory Accounts
Exhibit G:	Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants
Exhibit H:	Rate Design for Uniform Transmission Rates

9. In accordance with the *Filing Requirements* and the Board's October 18, 2012 *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A*

Performance-Based Approach, this Application also incorporates enhanced reporting on customer engagement and a proposed scorecard to measure performance.

10. The evidence relied on for the relief sought this Application provides a full description of all costs common to the Applicant's distribution and transmission activities, but the proposed rates are based only upon those costs appropriately allocated to the transmission business.

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

12. Subject to any settlement reached with intervenors, it is Hydro One's preference that the Board hears its Application in an oral hearing. Hydro One believes that an oral hearing is the most expeditious forum to address multiple topics that will be issues in the proceeding.

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

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

a) The Applicant:

Ms. Erin Henderson
Senior Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower
	483 Bay Street
	Toronto, ON M5G 2P5
Mailing Address:	7th Floor, South Tower
	483 Bay Street
	Toronto, ON M5G 2P5
Telephone:	(416) 345-4479
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Electronic access:	Regulatory@HydroOne.com

b) The Applicant’s counsel:

Mr. Gordon M. Nettleton
McCarthy Tétrault LLP

Address for personal service: Suite 5300, TD Bank Tower
Box 48, 66 Wellington Street West
Toronto ON M5K 1E6

Telephone: (416) 362-1812
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Electronic access: gnettleton@mccarthy.ca

DATED at Toronto, Ontario, this 31st day of May, 2016.

HYDRO ONE NETWORKS INC.
By its counsel,

Signed on May 31, 2016 by Gordon M. Nettleton

Gordon M. Nettleton

EXECUTIVE SUMMARY OF APPLICATION

1. SCOPE OF APPLICATION

Hydro One Networks Inc. ("Hydro One") is applying for an Order approving the revenue requirement, cost allocation and rates for Hydro One's transmission business for years 2017 and 2018 ("test years") under the assigned docket number EB-2016-0160.

This executive summary addresses the requirements listed in Section 2.3.1 of Chapter 2 of the Ontario Energy Board's (the "Board") *Filing Requirements for Electricity Transmission Applications* issued on February 11, 2016.

In this Application, Hydro One is requesting the Board's approval of:

- rates revenue requirements of $1,505 million for 2017 and $1,586 million for 2018;
- charge determinants by rate pools to assist in the development of Uniform Transmission Rates effective January 1, 2017;
- the performance scorecard proposed in this Application;
- the continuation of the regulatory accounts discussed in Section 10 of this Exhibit; and
- the disposition of regulatory accounts with a net credit balance of $95.6 million effective January 1, 2017.

The requested rates revenue requirements reflect a year-over-year increase of 1.6% for 2017 versus 2016 Board-approved levels and 5.4% for 2018 versus 2017. After adjusting for the load forecast, the requested increase in 2017 is 3.7%. The requested increase for 2018 is unchanged and remains 5.4%.

The estimated increase of the total bill for Hydro One general service energy (2000 kWh/month) customers is 0.1% in 2017 and 0.2% in 2018. For Hydro One medium density residential (750 kWh/month) customers, the estimated increase is 0.2% in 2017 and 0.3% in 2018. The estimated bill impact for transmission connected-customers is 0.3% in 2017 and 0.4% in 2018, assuming that transmission represents 8.3% of the average transmission-connected customer's total bill.

The applied-for rate increase is likely to be mitigated by anticipated reductions in transmission pension contribution operating expenses, arising from the receipt of an updated actuarial valuation report that was not finalized at the time this Application was filed. The report is expected to be finalized at the end of June 2016. These circumstances are described further in Section 7 of this Exhibit.

2. OVERVIEW OF HYDRO ONE'S INVESTMENT PLAN

2.1 Strategic Goals, Values and Objectives

Hydro One aspires to be a best-in-class, customer-centric, commercial utility. Consistent with its past performance and its new status as a commercial entity, Hydro One remains committed to delivering safe, reliable power, and supporting the sustainable development of the Ontario economy. The company's core values remain unchanged:

- Maintaining a safe workplace;
- Caring for customers;
- Operating as one company;
- Being people-powered; and
- Executing with excellence.

Hydro One's new executive leadership and Board of Directors are committed to building a stronger performance management culture and are focused on achieving excellence in execution in all aspects of the company's work. The ability to measure and track performance is essential to this vision, as set out in Exhibit B2, Tab 1, Schedule 1 of this Application and Section 6 of this Exhibit. Hydro One's commitment to productivity and cost efficiency is further illustrated in Section 7 of this Exhibit, as OM&A expenses are expected to demonstrate a declining trend in the 2016 bridge year and in the 2017 and 2018 test years.

In order to achieve its corporate goals, Hydro One is also in the process of devising new approaches relating to serving its customers, forming its investment plans, and operating and maintaining its assets, while maintaining a strong commitment to safety and the environment.

The principles of the Board's *Renewed Regulatory Framework for Electricity Distributors* ("RRFE") are consistent and directly aligned with Hydro One's aspirations. Key areas of focus for Hydro One include ensuring that transmission services, capital program execution, and customer operations are more efficient and effective, enhancing the internal performance management culture, and strengthening relationships with key stakeholders. The Transmission System Plan, summarized in Section 4 of this Exhibit, reflects the alignment between Hydro One's values and business objectives with the RRFE, as set out in Exhibit B1, Tab 1, Schedule 2 and in Table 1 below.

Table 1: Hydro One's Values and Business Objectives

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Maintain top quartile reliability relative to transmission peers
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB

Hydro One submits that the forecasted expenditures and associated timing described in this Application are necessary if these objectives are to be achieved.

2.2 Customer Engagement and Needs Assessment

Hydro One's goal is to engage with customers consistently and proactively to better understand the customer and enhance the company's ability to provide services that meet their needs and improve customers' overall satisfaction with the service they receive. One critical element of achieving this goal is the development of an investment plan that is outcome-focused and designed to meet customers' needs and preferences.

In preparing this Application, Hydro One has engaged in an intense and focused level of customer engagement, which is detailed in Exhibit B1, Tab 2, Schedule 2. The company found the feedback from these sessions to be critical in understanding customer preferences and being better able to identify customer needs. Customers indicated that the consultations were valuable to them in understanding Hydro One's operations and investment process.

Hydro One expects to continue to engage customers in the future, not only to receive input to consider in the development of future investment plans, but also to receive feedback and communicate key information about the system and investments that have or are likely to impact transmission system reliability risk and actual system performance.

Based on Hydro One’s customer engagement process, the company believes that any deterioration in current service levels is unacceptable to customers and that the maintenance of current reliability levels is a customer priority.

2.3 Asset Needs Assessment

Based on Hydro One’s assessment of its transmission system, a significant portion of its assets have deteriorated to the point where they pose a risk to its business objectives of maintaining current levels of reliability and improving customer satisfaction. Detailed information on Hydro One’s asset needs is provided in Exhibit B1, Tab 2, Schedules 4 to 6.

Hydro One continues to strike a careful balance between: (a) developing the transmission system and building new infrastructure; (b) sustaining existing assets and maintaining the health of the system; and (c) rate impacts on customers. Between 2009 and 2012, Hydro One invested heavily in system development, in order to comply with government policies related to the connection and integration of renewable energy generation and the retirement of coal-fired generation. Since then, system development needs have declined while system renewal needs have increased to the point of creating risk to current reliability levels.

As described in Exhibit B1, Tab 2, Schedule 4, Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. This approach is new for Hydro One, and the company intends to develop the reliability risk approach and refine its application.

Reliability risk is a metric that is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement. Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability risk model is not used to identify specific asset needs and investments. Instead, these are determined by condition assessments and other asset-specific information, as described in Exhibit B1, Tab 2, Schedule 5.

Table 2 below reflects the relative change in risk for each critical asset class and for the system as a whole, as a result of 2017 and 2018 investments. With the planned investments, overall reliability risk would improve (i.e. decline) by 2% by 2019. Without the applied-for investments that are reflected in the 2017 and 2018 test years, overall reliability risk would deteriorate by 10%.

Table 2: Relative Change in Reliability Risk

	Relative Change in Risk from Jan. 1, 2017 to Dec. 31, 2018, as per proposed investment	**Relative Change in Risk from Jan. 1, 2017 to Dec. 31, 2018, without investment**	**% of Interruption Duration***
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

In addition to incorporating customer feedback and new information on system reliability risk, Hydro One also considered and incorporated the results of a total cost benchmarking study into the development of its Transmission System Plan (Exhibit B1, Tabs 1 to 4 of this Application). The study found that Hydro One's historical capital spending levels were significantly below median in its peer group. For the purposes of developing its investment plan, Hydro One used the total cost benchmarking study as a reference tool to further validate the proposed increases in spending associated with its Transmission System Plan. Based on the results of the report and Hydro One's investment proposal, the 2017 and 2018 total expenses (capital expenditures and OM&A) will still remain at or below median levels relative to the company's peer group.

[1] Represents all other assets; risk is assumed to be flat over the investment planning horizon for these assets

3. FINANCIAL SUMMARY

3.1 Revenue Requirement

A comparative profile of the annual rates revenue requirement build-up from 2016, the last Board-approved rate year, to 2018 is provided in Table 3, along with references to the Exhibits in the Application that discuss each cost component.

Table 3: Revenue Requirement ($ Millions)

Comparison of Rates Revenue Requirement	Board - approved 2016	2017	2018	Exhibit Reference
OM&A	436.7	413.1	411.2	C2-1-1
Depreciation	397.3	435.7	470.7	C2-3-1
Income Taxes	72.2	81.3	90.4	C2-4-1
Cost of Capital	661.5	676.1	714.9	D2-4-1
Total Revenue Requirement	**1,567.6**	**1,606.3**	**1,687.2**	E2-1-1
Deduct External Revenues	(32.2)	(28.2)	(28.5)	E1-2-1
Revenue Requirement less External Revenues	**1,535.4**	**1,578.1**	**1658.7**	
Deduct Export Revenue Credit	(31.7)	(39.2)	(40.1)	H1-4-1
Deduct Regulatory Accounts Disposition	(36.1)	(47.8)	(47.8)	F1-1-3
Add Low Voltage Switch Gear	13.0	14.0	14.7	G1-3-1
Rates Revenue Requirement	**1,480.7**	**1,505.1**	**1,585.6**	
Rate Increase Required, excl. Load		**1.6%**	**5.4%**	
Estimated Load Impact		2.1%	0.0%	E1-3-1
Rate Increase Required		**3.7%**	**5.4%**	

The increase in total rates revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation and the return on capital. Higher income taxes and lower external revenues also contribute to the difference. These are partially offset by a lower cost of debt, lower OM&A costs, increased regulatory account disposition, and a higher export revenue credit as described in Exhibit E1, Tab 1, Schedule 1 .

3.2 Budgeting Assumptions

In developing its investment plan, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.3% and 1.3%, respectively, in 2017 and of 2.5% and 1.6% in 2018. These assumptions are explained in further detail in Exhibit B1, Tab 2, Schedule 7.

3.3 Load Forecast Summary

Table 4 sets out Hydro One's 2017-2018 transmission system load forecast, which includes the impact of conservation and demand management and embedded generation.

Table 4: Hydro One's 2017-2018 Load Forecast (12-Month Average Peak in MW)

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2017	20,373	20,405	19,741	16,872
2018	20,378	20,410	19,746	16,876
Comparison to Board-approved Forecast for 2016				
2017	-2.6%	-1.9%	-2.1%	-2.6%
2018	-2.6%	-1.9%	-2.1%	-2.6%

The forecast was developed using the econometric and end-use approaches described in Exhibit E1, Tab 3, Schedule 1. The forecast base year was corrected for abnormal weather conditions, and growth rates were applied to the normalized base year value. Consistent with the IESO's approach, normal weather data is based on the average weather conditions experienced over the last 31 years.

4. TRANSMISSION SYSTEM PLAN

Hydro One's Transmission System Plan is set out in Exhibit B1, Tabs 1 to 4.

The proposed five-year capital plan reflects Hydro One's understanding of the investments required to meet the reliability needs, risk tolerance, and power quality needs of its customers. Hydro One expects the plan to result in several key outcomes for Hydro One and its customers:

- Mitigation of risk arising from aging and deteriorating assets;
- Creation of conditions that enable Hydro One to continue to provide first quartile reliability in a safe manner to its customers;
- Avoidance of larger capital replacement costs by extending asset life, where feasible;
- Ensured compliance with regulatory, environmental and reliability standards; and
- Drive towards an injury-free workplace.

To achieve these outcomes, Hydro One has shifted the balance of capital investment towards sustainment capital, with a focus on lines investments. The company has also approached the timing and pacing of investments with a long-term view. In its previous transmission revenue requirement application for the 2015-2016 period, the company had put forth a sustainment capital program that began to address the need for higher sustainment investments, by focusing on stations assets in poor condition that were a significant driver of reliability performance. Since its last filing, Hydro One has focused on developing an improved understanding and knowledge of the condition of its transmission system.

The company has gained additional knowledge through the ongoing testing of critical assets and expansion of the scope of condition assessments, combined with information collected about the actual performance (including failures) of individual assets. Hydro One has also been developing a greater understanding of how equipment unavailability, due to condition and demographics, is a leading indicator of future reliability issues, contributing to higher reliability risk. As a result of these efforts, Hydro One is continuing to prioritize asset replacements with a goal of maintaining top quartile reliability and reducing reliability risk on the system.

Hydro One has relied on maintenance programs to extend the lifespan of assets by addressing asset condition deficiencies, where practical, as a means of deferring large capital expenditures. As a result, many assets are being operated beyond their expected service life.[2] Although this approach defers capital investments, it increases maintenance costs and the risk that assets will fail, deteriorate significantly, or become obsolete as spare parts and manufacturer support become unavailable. Recent examples of this manifest risk include equipment failures in 2015 and 2016 at Elgin TS, Horning TS, Bridgman TS, and Frontenac TS.

As a result of its recent efforts to invest in the sustainment of stations assets, Hydro One has made significant strides in stabilizing the reliability risk from its stations assets. However, lines assets have continued to deteriorate and are now contributing to a larger proportion of the system's reliability risk. Hydro One expects to transition to placing a greater emphasis on lines-related sustainment investments (beginning in 2018) while maintaining a prudent level of stations investment in order to continue to mitigate risk.

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[2] Expected service life: the average time in years that an asset can be expected to operate under normal system conditions

In developing its Transmission System Plan, Hydro One was aware that execution of the plan will take place in the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. Due to the planned refurbishment of large nuclear power plants in 2021 and beyond, Hydro One expects to face greater constraints to outage scheduling in the future. As a result, it has planned the pace of sustainment work so that critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service before expected outage constraints make work more difficult to complete.

Hydro One is sensitive to the impacts of the investment plan on its customers, and thus has taken steps to ensure a prudent approach to investment and continued alignment with principles of RRFE by:

- ensuring that the investment plan reflects customer needs and preferences identified in the customer engagement process, is consistent with the feedback obtained from the various other customer consultations undertaken by the company, and is aligned with the company's responsibility to provide effective stewardship of its transmission system assets;
- identifying specific opportunities (e.g., steel tower coating) where the company can extend the useful life of its assets and mitigate higher capital spending requirements for asset replacements in the future;
- actively driving cost reduction and improved productivity to help offset the customer rate impacts of the proposed investment plan; and
- implementing an improved performance management system to provide greater transparency to the Board, customers, and Hydro One's management, and to create

confidence that targeted work is completed in an efficient manner, while delivering the promised outcomes for Hydro One's customers.

As further described in Exhibit B1, Tab 3, Schedule 1, Hydro One's capital expenditure forecast for 2017 is $1,076 million for 2017 and $1,122 million for 2018. Table 5 summarizes the capital investment plan.

Table 5: Summary of Transmission Capital Budget ($ Millions)

Including Capitalized Overheads and Interest Capitalized*	**Historic**				**Bridge Year**	**Test Years**		**Forecast**		
Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Sustaining	389.3	480.0	621.3	694.3	724.3	776.8	842.1	825.7	915.2	1118.1
Development	329.4	171.7	131.6	166.0	166.0	196.4	170.2	244.0	254.0	258.3
Operations	15.2	17.7	28.4	15.6	30.1	25.4	30.8	58.8	21.1	24.7
Common Corporate Costs Capital	42.1	49.1	63.4	67.1	83.5	77.6	79.1	79.1	78.2	73.8
Total	**776.0**	**718.5**	**844.6**	**943.0**	**1003.8**	**1076.1**	**1122.2**	**1207.5**	**1268.6**	**1474.9**

*Includes Allowed Funds Used During Construction.

A key area of focus for the Transmission System Plan is ensuring that transmission services and capital work execution are more efficient and effective. This is discussed in Exhibit B1, Tab 4, Schedule 1.

5. RATE BASE

Exhibit D1, Tab 1, Schedule 1 provides the details of the derivation of the requested rate base figures for the test years. Table 6 summarizes this request.

Table 6: Transmission Rate Base* ($ Millions)

Description	2017	2018
Gross Plant	16,641.1	17,616.4
Less: Accumulated Depreciation	(6,113.4)	(6,418.7)
Net plant in service	**10,527.8**	**11,197.7**
Working Capital	26.6	27.8
Total Rate Base	**10,554.4**	**11,225.5**

*Gross plant and accumulated depreciation values are calculated using a mid-year approach. Third party capital contributions have been netted out.

Table 7 compares 2016 forecast rate base to the 2016 rate base approved by the Board in its Decision on Hydro One's previous transmission application EB-2014-0140.

Table 7: 2016 Board-approved versus 2016 Bridge Year Forecast Rate Base ($M)

Rate Base Component	**2016 Bridge Year (Forecast)**	**2016 Board-approved**	**Variance**
Gross Plant	15,794.8	15,805.2	(10.4)
Less: Accumulated Depreciation	(5,802.8)	(5,787.7)	15.1
Net Utility Plant	9,992.0	10,017.5	(25.5)
Cash Working Capital*	8.5	8.5	0.0
Materials & Supplies Inventory	11.7	14.0	(2.3)
Total Rate Base	10,012.2	10,040.0	(27.8)

* Hydro One does not calculate actual cash working capital, thus the 2016 approved amount was used for illustrative purposes.

Total rate base is expected to be $27.8 million below the Board-approved amount, a variance of 0.3%.

6. PERFORMANCE AND REPORTING

Hydro One's new executive leadership and Board of Directors are committed to building a stronger performance management culture and are focused on achieving excellence in execution in all aspects of the company's work. The ability to measure and track performance is essential to this vision.

Two critical elements of the journey towards stronger performance culture are: (i) the development of a scorecard; and (ii) the selection of key performance indicators that measure the drivers of the company's performance and track productivity improvements.

Exhibit B2, Tab 1, Schedule 1 discusses the cost efficiencies, productivity improvements and key performance indicators ("KPIs") that Hydro One is implementing to ensure that its business objectives are aligned with the principles of the RRFE.

In Exhibit B2, Tab 1, Schedule 1, Hydro One has provided a performance scorecard that will track its performance in areas directly tied to its own business objectives, which are aligned with those of the RRFE. The metrics contained in the scorecard will provide the Board and stakeholders visibility into how the company performs in a variety of areas, including cost control. The proposed scorecard is replicated in Table 8.

1 **Table 8: Proposed Transmission Scorecard**

RRFE Principle	Category	Metric	*Definition*
Customer Focus	Service Quality	Satisfaction with Outage Planning Procedures	*% satisfied in OGCC survey*
		Customer Delivery Point Performance Standards Outliers (as % of total delivery points)	*% of total delivery points designated as outliers*
	Customer Satisfaction	Overall % satisfied in corporate survey	*Transmission customers (Industrial, Generators, LDC) only*
Operational Effectiveness	Safety	# of recordable incidents per 200,000 hours	*Average # of incidents per 200K hours*
	System Reliability	Average. # of sustained interruptions per delivery point	*T-SAIFI-S*
		Average # of momentary interruptions per delivery point	*T-SAIFI-M*
		Average minutes that power to a delivery point is interrupted	*T-SAIDI*
		System unavailability (%)	*% of system not available for use*
		Unsupplied energy (minutes)	*Unsupplied MW-minutes/Peak MW*
	Asset Management	In-service additions as % of OEB-approved plan	*$ ISA as percentage of Planned $ Amounts*
		Capital expenditures as % of Budget	*$ Capital expenditures as % of Budgeted $ Capital expenditures*
	Cost Control	Total OM&A and Capital expenditures/Gross fixed asset value	*OM&A and Capital expenditures/ Gross fixed assets*
		Sustainment capital /Gross fixed asset value	*Sustainment Capital expenditures/ Gross fixed assets*
		OM&A/Gross fixed asset value	*OM&A/ Gross fixed assets*
Policy Response	Renewables	% of new connection impact assessments completed on time	*Total assessments completed within expected time/Total connections requested*

	Regulatory Compliance	NERC & NPCC Standards Compliance – High impact issues	*# of high impact compliance violations as defined by NERC/NPCC*
		NERC & NPCC Standards Compliance – Medium/low impact issues	*# of medium/low impact compliance violations as defined by NERC/NPCC*
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met	*Total deliverables met/Total deliverables expected*
Financial Performance	**Leverage**	Debt to Equity Ratio	*Debt (including Short &Long Term)/ Equity*
	Liquidity	Current Ratio (Current Assets/Current Liabilities)	*Current Assets/Current Liabilities*
	Profitability	Return on Equity (deemed)	*Included in rates*
		Return on Equity (achieved)	*Actual return on equity*

Exhibit B1, Tab 1, Schedule 3 provides Hydro One's performance data relating to three of its business objectives: safety, customer satisfaction and reliability.

7. OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A) EXPENSE

A summary of forecast operations, maintenance and administration ("OM&A") expenses for the test years are provided at Exhibit C1, Tab 2, Schedule 1. Forecast OM&A expenses are expected to demonstrate a declining trend in the 2016 bridge year and in the 2017 and 2018 test years, despite upwards pressure from inflation of approximately 2% per year, a growing asset base, and increasing compliance costs arising from new regulatory standards, such as the North American Electric Reliability Corporation's ("NERC") Critical Infrastructure Protection ("CIP") Cyber Security reliability standards. Table 9 provides a summary of forecast OM&A expenditures.

Table 9: Summary of Transmission OM&A Budget ($ Millions)

Description	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
Sustaining	204.7	221.0	228.6	233.6	227.5	241.2	238.5
Development	8.5	8.6	7.5	6.1	5.3	4.8	5.0
Operations	54.8	56.7	56.6	59.0	60.0	61.3	62.1
Customer Care	4.4	5.3	5.4	5.1	4.1	4.0	3.9
Common Corporate and Other OM&A	80.7	75.8	37.2	73.9	72.3	49.9	47.5
Taxes Other Than Income Taxes	62.1	21.2	64.1	63.9	62.9	63.6	64.3
Pension Adjustment*	-	-	-	-	-	-11.0	-8.0
B2M LP Adjustment*	-	-	-	-	-	-0.8	-2.1
Total	**415.2**	**388.4**	**399.5**	**441.6**	**432.1**	**413.1**	**411.2**

*See Exhibit C1, Tab 2, Schedule 1 for further details.

Total OM&A expenditures for test year 2017 are forecast to be $413.1 million, which is a decrease of $19 million or 4.4% from the 2016 bridge year. Total OM&A expenditures for test year 2018 are forecast to further decrease by $1.9 million or 0.4% versus 2017.

The test year expenditures are required to address the increasing maintenance requirements of a deteriorating, but expanding transmission system.

Table 10 compares 2016 projected costs to the 2016 OM&A expenditures approved by the Board in its Decision on Hydro One's previous transmission application in EB-2014-0140.

Table 10: 2016 Board-approved versus 2016 Projected OM&A Expenditures

OM&A Categories	**2016 Board-approved ($ Millions)**	**2016 Projected ($ Millions)**	**Variance ($ Millions)***
Sustaining	241.1	227.5	-13.6
Development	13.4	5.3	-8.1
Operations	59.1	60.0	0.9
Customer Care	5.5	4.1	-1.4
Common Corporate & Other Costs	71.3	72.3	1.0
Taxes Other Than Income Taxes	67.0	62.9	-4.1
Less settlement reduction	-20.0		
Exclusion of B2M	-0.7		
Total OM&A	**436.7**	**432.1**	**-4.6**

*Total Variance is not the sum of changes noted.

Hydro One's projected 2016 OM&A costs are $4.6 million lower or 1.1% below Board-approved levels. The Board-approved amounts include the $20.0 million reduction negotiated in the EB-2014-0140 settlement agreement. Most areas were meaningfully below target including Sustaining, Development and Taxes Other Than Income Taxes.

Details of Hydro One's corporate staffing and compensation are provided at Exhibit C1, Tab 4, Schedule 1. As noted at Exhibit C1, Tab 4, Schedule 2, Hydro One has engaged Willis Towers Watson to prepare an actuarial valuation report relating to Hydro One's defined benefit pension plan as at December 31, 2015. Although the report was not finalized as of the date of filing this Application, Hydro One expects the final valuation to be available at the end of June 2016. In addition to the changes in employee contribution rates, the valuation will also reflect updated investment returns, changes in employee benefits, and updated actuarial assumptions. It is anticipated that the valuation will demonstrate a further reduction in Hydro One's pension contribution operating expenses. To ensure that Hydro One's rates for the 2017 and 2018 test years reflect the anticipated reduction in costs, Hydro One will submit an update to this Application to reflect the actual changes shortly after the final valuation is received.

8. COST OF CAPITAL

Table 11 summarizes the cost of capital parameters reflected in the Application, details of which can be found at Exhibit D1, Tab 4, Schedule 1.

Table 11: Cost of Capital

Comparison of Cost of Capital and Rate Base	**Board-approved 2016**	**2017**	**2018**	**Exhibit Reference**
Cost of Debt	4.77%	4.48%	4.42%	D2-4-2
Cost of Equity	9.19%	9.19%	9.19%	D2-4-1
Total Debt ($Millions)	6,024.0	6,332.6	6,735.3	
Total Equity ($Millions)	4,016.0	4,221.7	4,490.2	
Rate Base ($ Millions)	**10,040.0**	**10,554.3**	**11,225.5**	D2-1-1
Weighted Average Cost of Capital		**6.4%**	**6.3%**	

Hydro One's deemed capital structure for transmission ratemaking purposes is 60% debt and 40% common equity. The 60% deemed debt component is comprised of 4% short-term debt and 56% long-term debt. Hydro One will continue to use the Board's cost of capital parameters for its deemed short-term debt rate and return on equity, consistent with the Board's report on cost of capital.

Hydro One's Application reflects a return on equity of 9.19% for each of the 2017 and 2018 test years, based on the cost of capital parameters released by the Board on October 15, 2015, for rates effective January 1, 2016. Hydro One will update the return on equity and the cost of short-term debt annually in accordance with the Board's formulaic approach for the purpose of establishing the final revenue requirements for both 2017 and 2018.

Hydro One also proposes to use and update annually its own actual forecast weighted average long-term debt rate, which is market-determined, consistent with its past Board-approved practice (EB-2012-0031, EB-2014-0140) for the purpose of establishing the final revenue requirement for both 2017 and 2018 test years.

9. COST ALLOCATION AND RATE DESIGN

Hydro One continues to follow the Board-approved methodology (EB-2014-0140), for allocating its transmission rates revenue requirement into three rate pools, Network, Line Connection, Transformation Connection, as set out in in Exhibits G1, Tab 1, Schedule 1 through Exhibit G1, Tab 3, Schedule 1 and summarized in Table 12.

The rate pools are based on functional categories of assets and their associated costs. Rates revenue requirement is apportioned amongst the rate pools using direct assignment, to the extent possible.

Table 12: Summary of Rates Revenue Requirement by Rate Pool ($ Millions)

Revenue Requirement (Year)	Network	Line Connection	Transformation Connection	Total
2017	853.4	214.3	437.1	1,504.7
2018	898.9	226.4	460.0	1,585.3

10. DEFERRAL AND VARIANCE ACCOUNTS

Hydro One requests the continuation over the test years of the following regulatory accounts, as described in Exhibit F1, Tab 1, Schedule 1:

- Excess Export Service Revenue;
- External Secondary Land Use Revenue;
- External Station Maintenance, E&CS Revenue and Other Revenue;
- Tax Rate Changes;
- Rights Payments;
- Pension Cost Differential;
- East West Tie Deferral Account – Incumbent Transmitter;
- Long-Term Transmission Future Corridor Acquisition and Development Account;
- North West Bulk Transmission Line Account;
- Supply to Essex County Transmission Reinforcement Account;
- External Revenue – Partnership Transmission Projects Account; and
- In-Service Capital Additions Variance Account.

Hydro One requests the discontinuation of the Local Distribution Company Conservation and Demand Management and Demand Response Variance Account, which was established pursuant to a settlement agreement approved by the Board in proceeding EB-2012-0031, as Hydro One has fulfilled its related obligations.

Hydro One is requesting disposition of the actual audited regulatory account values as at December 31, 2015, plus forecast interest improvement accrued in 2016, on the principal balances as at December 31, 2015 less any amounts approved for disposition in 2016 by the Board in the EB-2014-0140 rate filing for transmission rate years 2015 and 2016 as described in Exhibit F1, Tab 1, Schedule 3.

It is expected that new transmission rates will be effective and implemented on January 1, 2017 and that disposition of the accounts requested will commence on that date.

Hydro One's requested reduction to the revenue requirement of $95.6 million over 2017 and 2018 is detailed in Table 13.

Table 13: Transmission Disposition of Regulatory Account Balances ($ Millions)

Description	**Forecast Balance as at Dec 31, 2016 ($ Millions)**
Excess Export Service Revenue	(18.5)
External Secondary Land Use Revenue	(26.7)
External Station Maintenance and E&CS Revenue	0.7
Tax Rate Changes	0.1
Rights Payments	(3.0)
Pension Cost Differential	6.0
Long-Term Transmission Future Corridor Acquisition and Development	0.6
CDM Variance Account	(54.0)
External Revenue – Partnership Transmission Projects Account	(0.9)
Total Regulatory Accounts for Approval	**(95.6)**

10.1 Bill Impacts

Exhibit H1, Tab 5, Schedule 1 provides the bill impacts that would result from approval of this Application. Table 14 shows the average bill impacts of the proposed changes in transmission revenue requirement and load forecast in 2017 and 2018.

Table 14: Average Bill Impacts on Transmission and Distribution-Connected Customers

	2016	**2017**	**2018**
Rates Revenue Requirement ($ millions)*	**1,480.5**	**1,504.7**	**1,585.3**
% Increase in Rates RR over prior year		1.6%	5.4%
% Impact of load forecast change		2.1%	0.0%
Net Impact on Average Transmission Rates		**3.7%**	**5.4%**
Transmission as a % of Tx-connected customer's total bill		8.3%	8.3%
Estimated Average Bill impact		***0.3%***	***0.4%***
Transmission as a % of Dx -connected customer's total bill		6.8%	6.8%
Estimated Average Bill Impact		***0.3%***	***0.4%***

* This amount is net of the $0.3 million in wholesale meter service revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.

The total bill impact for Hydro One medium density residential (R1) customers consuming 350 kWh, 750 kWh and 1800 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 15.

Table 15: Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	350 kWh	**750 kWh**	**1800 kWh**
Total Bill as of Jan 1, 2016*	$ 102.95	$ 179.37	$ 379.98
RTSR included in 2016 R1 Customer's Bill	$ 4.37	$ 9.36	$ 22.47
Estimated 2017 Monthly RTSR**	$ 4.52	$ 9.69	$ 23.26
2017 Increase in Monthly Bill	**$ 0.15**	**$ 0.33**	**$ 0.79**
2017 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2018 Monthly RTSR**	$ 4.75	$ 10.18	$ 24.44
2018 Increase in Monthly Bill	**$ 0.23**	**$ 0.49**	**$ 1.18**
2018 increase as a % of total bill	*0.2%*	*0.3%*	*0.3%*

* Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
** The impact on RTSR is assumed to be the net impact on average transmission rates, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

The total bill impact for a typical Hydro One general service energy less than 50 kW ("GSe < 50 kW") customer consuming 1000 kWh, 2000 kWh and 15,000 kWh monthly is determined based on the forecast increase in the customer's RTSR as detailed below in Table 16.

Table 16: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of Jan 1, 2016*	$ 262.79	$ 492.00	$ 3,471.80
RTSR included in 2016 GSe Customer's Bill	$ 10.19	$ 20.39	$ 152.89
Estimated 2017 Monthly RTSR**	$ 10.55	$ 21.11	$ 158.29
2017 increase in Monthly Bill	**$ 0.36**	**$ 0.72**	**$ 5.40**
2017 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*
Estimated 2018 Monthly RTSR**	$ 11.09	$ 22.18	$ 166.32
2018 increase in Monthly Bill	**$ 0.53**	**$ 1.07**	**$ 8.02**
2018 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*

* Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
** The impact on RTSR is assumed to be the net impact on average transmission rates, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

HYDRO ONE NETWORKS INC. TRANSMISSION PRO FORMA STATEMENT OF INCOME BRIDGE YEAR (2016) AND TEST YEARS (2017 AND 2018)

Line No.	Particulars	2016 (a)	2017 (b)	2018 (c)
	Revenues			
1	Retail power & energy	1,505	1,581	1,661
2	Commodity flow-through	-	-	-
3	LV	-	-	-
4	Other	28	28	28
5		1,533	1,609	1,689
	Costs			
6	OM&A	436	419	415
7	Cost of power	-	-	-
8	Depreciation	387	436	471
9	Capital tax	-	-	-
10		823	854	885
11	Earnings before interest and income tax	710	755	804
12	Interest expense	228	238	250
13	Earnings before income tax	482	516	554
14	Income tax	69	81	91
15	Net income	413	435	463

Witness: Samir Chhelavda

COST OF SERVICE SUMMARY

1. INTRODUCTION

This exhibit presents an overview of Hydro One Transmission's Cost of Service. As summarized in Exhibit C2, Tab 1, Schedule 1, the Cost of Service includes OM&A expenses, Depreciation and Amortization and Income Taxes, for which the overall costs for 2017 and 2018 are shown in Table 1 below:

Table 1: Costs of Service ($ Millions)

Description	Test Year	
	2017	**2018**
OM&A	413.1	411.2
Depreciation and Amortization	435.7	470.7
Income Taxes	81.3	90.4
Total Cost of Service	**930.1**	**972.3**

2. KEY ELEMENTS OF THE COST OF SERVICE

Hydro One Transmission's forecast cost of service has been developed consistent with corporate strategic goals to sustain a safe and reliable transmission system, as noted in Exhibit B1, Tab 1, Schedule 2. The Company's planning process is described in detail in Exhibit B1, Tab 2, Schedule 1.

2.1 Operation, Maintenance and Administrative Expenses (OM&A)

Total OM&A expenses for the 2017 test year are $413.1 million and for 2018 are $411.2 million.

Hydro One Transmission plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the Company. These work programs primarily address necessary improvements in infrastructure. Exhibits in support of OM&A costs have been prepared by function, and appear within the submitted evidence as follows in Table 2:

Table 2: OM&A Expenditures by Function

Particulars	2017 Total Cost ($ million)	2018 Total Cost ($ million)	Reference
Sustaining	241.2	238.5	Exhibit C1, Tab 2, Sch 2
Development	4.8	5.0	Exhibit C1, Tab 2, Sch 3
Operations	61.3	62.1	Exhibit C1, Tab 2, Sch 4
Customer Care	4.0	3.9	Exhibit C1, Tab 2, Sch 5
Shared Services	49.9	47.5	Exhibit C1, Tab 3, Sch 1
Taxes other than Income Taxes	63.6	64.3	Exhibit C1, Tab 3, Sch 7
Updated Pension Expense	**-11.0**	**-8.0**	**Exhibit C1, Tab 4 Sch 2**
Remove B2M Expenses	**-0.8**	**-2.1**	
Total OM&A Expenditures	**413.1**	**411.2**	**Exhibit C1, Tab 2, Sch 1**

2.2 Depreciation and Amortization Expense

The Company is proposing to recover $424.0 million in depreciation and amortization expense in 2017 and $460.6 million in 2018. Hydro One Transmission's evidence regarding the depreciation study and its impact on depreciation expense is filed at Exhibit C1, Tab 7, Schedule 1.

2.3 Income Taxes

As a result of *the Electricity Act, 1998*, Hydro One Transmission has been required to pay proxy taxes from 1999 to the time it ceased to be exempt from income tax under the *Income Tax Act* (Canada). Thereafter, Hydro One Transmission has been required to pay income tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario). Evidence outlining the calculation of Income Taxes of $81.3 million for 2017 and $90.4 million for 2018 appears in Exhibit C2, Tab 4, Schedule 1, Attachment 1.

3. KEY COMPONENTS IN THE BUILD-UP OF COST OF SERVICE

Key components in the build-up of Cost of Service are:

- resourcing,
- costing of work,
- out-sourced functions, and
- corporate cost allocation.

Each of these components is discussed below.

3.1 Resourcing

Labour costs are charged to OM&A and Capital work programs. The evidence contained at Exhibit C1, Tab 4 Schedule 1 presents total staff levels and costs incurred by the Company.

3.2 Costing of Work

OM&A and Capital work programs are comprised primarily of costs relating to labour, materials and equipment. Exhibit C1, Tab 5, Schedule 1 provides a schedule that explains how costs flow to work programs.

3.3 Outsourcing

As a strategy to reduce costs, improve efficiency and to improve focus on its primary operations, Hydro One has outsourcing arrangements with Inergi LP and Brookfield Asset Management. Evidence concerning these arrangements can be found in Exhibit C1, Tab 3, Schedule 2.

3.4 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to its Transmission and Distribution businesses and to other Hydro One subsidiaries on a centralized basis, as this serves as the most economic approach. The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs and assets are allocated based on cost drivers, direct benefits or other methods as appropriate. Exhibit C1, Tab 6 Schedule 1 describes these allocation methods, as well as the derivation of the overhead capitalization rate, which determines the assignment of overhead costs to capital expenditures.

SUMMARY OF OM&A EXPENDITURES

1. SUMMARY OF OM&A EXPENDITURES

This Exhibit provides an overview of Hydro One Transmission's OM&A expenditures over the 2012 to 2018 period.

Hydro One Transmission's OM&A programs represent the work required to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements (such as those specified within the Transmission System Code), environmental requirements and government direction. The forecast OM&A expenditures result from the investment planning process described in Exhibit B1, Tab 2, Schedule 7.

Hydro One Transmission's OM&A budget is grouped into the following investment categories: Sustainment, Development, Operations, Customer Care, Common Corporate and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Transmission's OM&A expenditures for the historical, bridge and test years.

Table 1: Summary of Transmission OM&A Expenditures ($ Million)

Description	2012	2013	2014	Historic 2015	Bridge 2016	Test 2017	Test 2018
Sustainment	204.7	221.0	228.6	233.6	227.5	241.2	238.5
Development	8.4	8.6	7.5	6.1	5.3	4.8	5.0
Operations	54.8	56.7	56.6	59.0	60.0	61.3	62.1
Customer Care	4.4	5.3	5.4	5.1	4.1	4.0	3.9
Common Corporate Costs and Other OM&A	80.7	75.8	37.2	73.9	72.3	49.9	47.5
Taxes Other Than Income Taxes	62.1	21.2	64.1	63.9	62.9	63.6	64.3
Pension Adjustment*	-	-	-	-	-	-11.0	-8.0
B2M LP Adjustment*	-	-	-	-	-	-0.8	-2.1
Total	**415.2**	**388.4**	**399.5**	**441.6**	**432.1**	**413.1**	**411.2**

* See section 8 of this Exhibit for details.

Total OM&A expenditures for test year 2017 are forecast to be $413.1 million, which is a decrease of $19 million or 4.4% below the 2016 bridge year. Total OM&A expenditures for test year 2018 are forecast to decrease by a further $1.9 million or 0.4% over 2017. The test year expenditures are required to address the increasing maintenance requirements of a deteriorating and expanding transmission system.

As Table 1 demonstrates, these forecast OM&A expenses demonstrate a declining trend in the 2016 bridge year and in the 2017 and 2018 test years, despite upwards pressure from inflation of approximately 2% per year, a growing asset base, and increasing compliance costs arising from new regulatory standards, such as the North American Electric Reliability Corporation's Critical Infrastructure Protection Cyber Security reliability standards.

2. SUSTAINMENT

The Sustainment OM&A budget represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. The proposed investments are intended to ensure that the overall reliability of the system is maintained, customer commitments are achieved, and all legislative, regulatory, environmental and safety requirements are met. Details are provided at Exhibit C1, Tab 2, Schedule 2.

3. DEVELOPMENT

Development OM&A expenditures consist of costs associated with developing technical standards, solutions, and expertise for the benefit of Hydro One's customers and Hydro One's business success. Development OM&A activities are described in detail in Exhibit C1, Tab 2, Schedule 3.

4. OPERATIONS

Operations OM&A costs reflect the annual expenditures required to perform the central transmission Operations function from Hydro One's Ontario Grid Control Centre. The transmission Operations function is concerned with the real-time operation of Hydro One Transmission's system equipment, including the monitoring, control, detection and response to equipment operational issues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5. CUSTOMER CARE OM&A

Hydro One Transmission's Customer Service OM&A investments fund work activities required to develop, implement and monitor the company's plans to positively influence customer relationships and ensure affordability and overall value for the products and services offered to them. These work activities will enable Hydro One to foster a relationship based on transparency and trust. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6. COMMON CORPORATE COSTS AND OTHER OM&A

The Common Corporate and other OM&A expenditures include costs associated with: common corporate functions and services ("CCFS"), asset management planning, information technology, and cost of sales for external work.

CCFS includes the following functions and services: corporate management, finance, human resources, corporate relations, general counsel and corporate secretariat, regulatory affairs, security management, internal audit, and real estate and facilities. Other OM&A expenses include an environmental provision, indirect depreciation and other costs. Asset management planning services include system investment and asset stewardship functions. IT activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure.

Details of these activities and associated costs are provided in Exhibit C1, Tab 3, Schedules 1 to 6.

7. TAXES OTHER THAN INCOME TAXES

These expenses consist of property and proxy taxes, and indemnity payments to the Province. Details of these expenditures are provided in Exhibit C1, Tab 3, Schedule 7.

8. PENSION AND B2M LP ADJUSTMENTS

Hydro One received an updated actuarial valuation report dated June 9, 2016, which is provided as Attachment 1 to Exhibit C1, Tab 4, Schedule 2. The report outlined changes in the financial position of Hydro One's pension plan as of December 31, 2015 since its last valuation of December 13, 2013. As a result of the updated valuation, the plan's operating expenses have decreased. Further details are set out in Exhibit C1, Tab 4, Schedule 2. Hydro One has reflected this change in the "Pension Adjustment" line in Table 1, reducing test year cost forecasts from those originally filed.

The "B2M LP Adjustment" line in Table 1 reflects adjustments for B2M LP costs that were inadvertently included at the time of filing this Application.

9. COMPARISON OF OM&A COSTS TO BOARD-APPROVED

Table 2 compares Hydro One Transmission's actual costs in 2015 to the 2015 OM&A expenditures approved by the Board in its Decision on Hydro One's previous transmission application (EB-2014-0140).

Table 2: 2015 Board-approved versus 2015 Actual OM&A Expenditures

OM&A Categories	**2015 Board-approved ($ Million)**	**2015 Actual ($ Million)**	**Variance ($ Million)**
Sustainment	238.7	233.6	-5.1
Development	12.9	6.1	-6.8
Operations	58.5	59.0	0.5
Customer Care	5.5	5.1	-0.4
Common Corporate & Other Costs	70.2	73.9	3.7
Taxes Other than Income Taxes	66.3	63.9	-2.4
Less settlement reduction	-20.0		
Exclusion of B2M	-0.9		
Total OM&A	**431.1**	**441.6**	**10.5**

*Total variance is not the sum of changes noted.

Hydro One Transmission's actual 2015 OM&A costs were $10.5 million or 2.4% above Board-approved levels. This difference is explained, in part, by the OM&A reduction prescribed by the settlement agreement (the "2015-2016 Settlement Agreement") that was accepted by the Board in proceeding EB-2014-0140. Most items were otherwise on or below target. Common Corporate costs increased by 5.3%, but this increase was offset by decreases in Sustainment (2.1%), Development (52.7%) and Taxes Other than Income Tax (3.6%).

Table 3 compares 2016 projected costs to the 2016 OM&A expenditures approved by the Board in its Decision in proceeding EB-2014-0140.

Table 3: 2016 Board-approved versus 2016 Projected OM&A Expenditures

OM&A Categories	**2016 Board-approved ($ Million)**	**2016 Projected ($ Million)**	**Variance ($ Million)***
Sustainment	241.1	227.5	-13.6
Development	13.4	5.3	-8.1
Operations	59.1	60.0	0.9
Customer Care	5.5	4.1	-1.4
Common Corporate & Other Costs	71.3	72.3	1.0
Taxes other than Income Taxes	67.0	62.9	-4.1
Less settlement reduction	-20.0		
Exclusion of B2M	-0.7		
Total OM&A	**436.7**	**432.1**	**-4.6**

*Total variance is not the sum of changes noted.

Hydro One Transmission's projected 2016 OM&A costs are $4.6 million or 1.1% below the Board-approved level, which includes the $20.0 million reduction negotiated in the 2015-2016 Settlement Agreement. Otherwise, most spending areas are meaningfully below target including Sustainment (5.6%), Development (60.4%) and Taxes other than Income Tax (6.1%).

SUMMARY OF COMMON CORPORATE COSTS - OM&A

Hydro One Common Corporate OM&A costs are comprised of common corporate functions and services ("CCFS"), asset management planning services, information technology ("IT"), cost of sales to external parties and other OM&A.

CCFS includes corporate management, finance, human resources, corporate communications, legal, regulatory affairs, corporate security, internal audit and real estate. Asset management planning includes system investment activities and asset stewardship planning and strategies. IT activities include providing and managing computer systems and installing enterprise IT systems. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

Hydro One utilizes a centralized shared services model to deliver its common services to its transmission and distribution businesses and to its affiliated companies as described in Exhibit A, Tab 5, Schedule 3. Many organizations have adopted a common corporate cost model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model in 1999.

Table 1 summarizes the Hydro One Transmission's portion of the Common Corporate OM&A Costs over the historic, bridge and test years.

Table 1: Summary of Common Corporate OM&A Costs 2012-2018 ($Millions)

Description	2012	2013	2014	Historic 2015	Bridge 2016	Test 2017	Test 2018
Asset Management	32.3	31.8	32.6	31.0	36.6	36.5	35.8
Common Corporate Functions & Services	80.5	87.7	93.1	95.7	98.9	98.3	97.6
Information Technology	60.7	61.1	55.2	55.1	61.4	59.8	57.6
Cost of Sales	11.4	13.9	11.1	8.8	5.0	5.0	5.0
Other OM&A	-104.2	-118.6	-154.8	-116.8	-129.6	-149.7	-148.5
Total	80.7	75.8	37.2	73.9	72.3	49.9	47.5

Since 2009, Hydro One has applied a cost allocation methodology developed by Black and Veatch Corporation which utilizes a breakdown of activities and drivers. In 2015, Hydro One commissioned Black and Veatch Corporation to update the methodology to allocate common costs among the business entities using the common services, as discussed in Exhibit C1, Tab 6, Schedule 1. Other OM&A costs are discussed in Exhibit C1, Tab 3, Schedule 3.

COMMON CORPORATE FUNCTIONS AND SERVICES AND OTHER OM&A

1. OVERVIEW

Hydro One has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These functions are referred to as "common corporate functions and services" ("CCFS").

This Exhibit discusses CCFS costs and other OM&A expenses, which are comprised of credits associated with capitalized overhead, environmental provisions, indirect depreciation and other costs.

2. COMMON CORPORATE FUNCTIONS AND SERVICES

CCFS is comprised of the following functions and services: corporate management, finance, human resources, corporate relations, general counsel and corporate secretariat, regulatory affairs, security management, internal audit, and real estate and facilities.

For comparison purposes, Table 1 presents the total CCFS costs between 2012 and 2018 as well as amounts allocated to Hydro One Transmission in the test years.

Table 1: CCFS Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Corporate Management	5.0	4.9	5.5	5.4	11.1	22.3	22.1	7.2	7.1
Finance	35.2	41.9	41.0	40.4	42.2	41.0	38.6	21.9	19.4
People and Culture	9.9	11.1	13.1	13.9	16.0	14.8	14.2	7.6	7.3
Corporate Relations	11.3	15.0	19.6	17.4	17.5	17.3	19.4	8.7	9.9
General Counsel and Secretariat	8.8	9.6	9.3	9.3	10.5	10.4	10.5	5.5	5.6
Regulatory Affairs	20.6	20.6	23.1	24.4	25.8	25.4	25.9	9.6	9.8
Security Management	3.1	3.4	3.5	4.2	5.1	4.7	4.8	2.2	2.3
Internal Audit	3.5	3.4	4.0	4.3	6.0	6.3	6.4	3.3	3.4
Real Estate and Facilities	54.6	54.1	53.6	60.0	60.1	59.6	60.7	32.2	32.7
Total CCF&S Costs	**152.0**	**164.0**	**172.8**	**179.4**	**194.2**	**201.8**	**202.7**	**98.3**	**97.6**

Total CCFS costs increase by $23.3 million from 2015 to 2018 primarily due to the following factors:

- higher Corporate Management costs due to increases in compensation;
- higher Internal Audit costs resulting from making rotational staff permanent and an increased staffing requirement to address an expanding work program;
- higher Regulatory Affairs costs reflecting an aggressive regulatory agenda and, beginning in 2015, the inclusion of business performance management costs previously included in Finance costs; and
- higher General Counsel and Corporate Secretariat costs to address an increasing workload and greater complexity in the company’s legal matters.

2.1 Corporate Management

Table 2 provides an overview of Hydro One's Corporate Management costs over the 2012-2018 period.

Table 2: Corporate Management Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Corporate Management	5.0	4.9	5.5	5.4	11.1	22.3	22.1	7.2	7.1

"Corporate Management" represents those functions responsible for providing overall strategic direction to Hydro One. Corporate Management costs relate to the Board of Directors, the Chief Executive Officer, the Treasurer, the Chief Financial Officer ("CFO") and the General Counsel and Corporate Secretariat as advisors to the Board of Directors and corporate officers on overall strategic matters.

Included in the total Corporate Management costs are expenses related to Hydro One's investor relations and corporate development functions. There has been no allocation of these expenses to Hydro One Transmission.

The allocation of Corporate Management costs between Hydro One's distribution and transmission businesses is determined by the common cost allocation methodology described in Exhibit C1, Tab 6, Schedule 1. The allocation of these costs between Hydro One and its affiliates is governed by affiliate service level agreements described in Exhibit A, Tab 5, Schedule 3. There is no service level agreement with Hydro One Limited.

The increase in 2015 Corporate Management costs and the 2016 to 2018 forecast costs stems from changes in compensation.

2.2 Finance

Hydro One's Finance division provides strategic advice and services related to planning, processing, recording, reporting and monitoring all financial transactions taking place within an organization. The Finance division performs the following functions: corporate controller services, corporate tax services, treasury services, and business planning and decision support.

Table 3 provides an overview of Hydro One's finance costs over the 2012-2018 period.

Table 3: Finance Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Finance	35.2	41.9	41.0	40.4	42.2	41.0	38.6	21.9	19.4

2.2.1 Corporate Controller

The corporate controller function provides leadership and direction regarding all performance management, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles.

This function oversees the development of actual and forecast financial information and manages reporting processes for appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company on internal control matters, employing measures such as "organization authority registers" and financial policies and procedures. It also provides leadership on compliance with Ontario securities laws, including Bill 198, and the Multi-Jurisdictional Disclosure System rules for a foreign-issuer registered with the U.S. Securities Exchange Commission.

Many routine financial services are outsourced to Inergi LP as described in Exhibit C1, Tab 3, Schedule 2, such as accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting and pension support, human resources pay services and a number of administrative services. The costs of these outsourced services comprise a major portion of the corporate controller costs.

Also included in corporate controller costs are costs associated with the Chief Risk Officer's department and the company's business planning and decision support function. The Chief Risk Officer's department is accountable for performing internal risk assessments to ensure the company is appropriately addressing risks. The business planning and decision support function is responsible for:

- establishing and leading the annual business planning and budgeting processes;
- performing business case reviews, business valuations, transaction support;
- developing and maintaining financial models; and
- providing analytical support for a variety of financial planning and reporting processes.

In 2015, business performance support services moved from the corporate controller function to the company's Regulatory Affairs division. These services support the development of business strategies by conducting studies on corporate performance in areas such as reliability, work program performance, productivity and cost savings management. See section 2.6.4 of this Exhibit for more information on this function.

The forecasted corporate controller costs are $33.2 million in 2017 and $30.8 million in 2018. The amounts allocated to Hydro One Transmission are $17.8 million in 2017 and $15.4 million in 2018.

2.2.2 Corporate Tax

Corporate tax services manage the tax affairs (namely, compliance, audits and planning) for each taxable entity within the Hydro One group of companies. This includes matters related to corporate income taxes, harmonized sales tax, debt retirement charge, payroll and non-resident withholding tax, and the employer health tax. Corporate tax services ensure that internal and external tax compliance requirements are met. Moreover, tax consulting services are provided to other departments with respect to mergers and acquisitions activities, payroll tax, taxable benefits, agreements, financing, and all transactions and information about tax costs for regulatory purposes.

The costs associated with corporate tax services are $3.1 million in 2017 and $2.8 million in 2018, with $1.5 million being charged to Hydro One Transmission in 2017 and $1.3 million in 2018.

2.2.3 Treasury

Treasury costs are associated with the following activities:

- executing on borrowing plans and issuing commercial paper and long-term debt;
- ensuring compliance with securities regulations, banks and debt covenants;
- managing the company's daily liquidity position, control cash and manage the company's bank accounts;
- settling all transactions and manage the relationship with creditors; and
- communicating with debt investors, banks and credit rating agencies.

A portion of the treasury budget is recovered through the cost of long-term debt, as stated in Exhibit D1, Tab 5, Schedule 1.

Included in treasury costs are expenses for the negotiation and purchase of insurance policies, and claims management and settlement. In 2017 and 2018, these expenses are forecast to be $4.5 million and $4.8 million, respectively. These expenses cover premiums paid for corporate shared services insurance coverage and the cost to self-insure against liability exposures that are either not covered by insurance policies or fall below the specified deductibles.

Table 4 shows the premiums for all of Hydro One Inc.'s insurance policies and the cost of self-insurance for the 2012-2018 period. Self-insurance costs for the 2017 and 2018 period reflect the company's risk exposures, its long-term history of claims, the deductible on the liability policies, and liability payments to third parties. The main contributor to self-insurance costs are claims by third parties which can fluctuate from year to year.

Table 4: Hydro One Inc. Insurance Costs ($ Millions)

Description	2012	2013	2014	2015	2016	2017	2018
Premiums paid for Corporate Functions and Services Insurance Policies *	1.3	1.4	1.5	1.6	2.5	2.7	2.8
Self-insurance Cost	1.3	1.5	2.9	1.2	1.9	1.9	1.9
Total	**2.6**	**2.8**	**4.4**	**2.9**	**4.3**	**4.5**	**4.8**

*****The cost of other insurance coverage that applies to only certain lines of business is captured and reported by the lines of business where the coverage is applicable.

Hydro One Transmission accounts for $2.6 million of the treasury budget for 2017 and $2.7 million of the budget for 2018.

2.3 People and Culture

The "People and Culture" organization ensures that Hydro One has the policies, systems and programs to attract, manage, engage and retain a high performing workforce to execute business strategy. The organization provides human resources consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits services, and labour relations services.

Table 5 provides an overview of the People and Culture organization's costs over the 2012-2018 period.

Table 5: People and Culture Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
People & Culture	9.9	11.1	13.1	13.9	16.0	14.8	14.2	7.6	7.3

The People and Culture organization performs multiple functions, which are described in this section.

2.3.1 Human Resources Operations

Hydro One's human resources function provides advice and guidance to managers, supervisors, and employees on a myriad of issues related to human resources policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff.

2.3.2 Talent Management

The talent management function recommends and administers policy in areas related to external hiring and leadership development. This function manages all of Hydro One's management/leadership development activities, including the assessment of high-potential succession candidates and miscellaneous specialized one-off hiring initiatives, as required. The talent management function also manages Hydro One's principal cyclical hiring and on-boarding processes, Hydro One's new grad training and development program, and the company's diversity plan.

2.3.3 Compensation and Benefits

The compensation and benefits function manages compensation, benefits, reporting and master data for all Hydro One's employees and pensioners by ensuring the accurate application, record-keeping and security of such information. This function provides regular, strategic reports to senior management on topics such as retirement demographics, headcount, overtime, and data for OEB submissions. This function facilitates the company's participation in industry-wide compensation, benefit and pension surveys. It also administers Hydro One's pension plan for approximately 7,100 pensioners and the benefits program for all employee groups.

2.3.4 Labour Relations

The labour relations function provides advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. The company is a party to 24 collective agreements and a number of mid-term agreements and letters of understanding. The labour relations function negotiates and administers all such agreements and letters of understanding.

2.4 Corporate Relations

Table 6 provides an overview of Hydro One's Corporate Communications costs over the 2012-2018 period.

Table 6: Corporate Communications Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Corporate Communications Total	11.3	15.0	19.6	17.4	17.5	17.3	19.4	8.7	9.9

Corporate Communications costs include expenses associated with Hydro One's First Nations and Métis relations function, outsourcing services function, and Hydro One's corporate communications and external relations function.

2.4.1 First Nations and Métis

Hydro One owns and maintains assets on reserve lands and within the traditional territories of First Nations and Métis peoples. Building relationships with First Nations and Métis communities based upon trust, confidence, and accountability is vital to achieving Hydro One's business objectives.

The First Nations and Métis Relations function is accountable for:

- supporting and sustaining long-term relationship-building and negotiations with First Nations and Métis communities impacted by the growth of Hydro One core work programs;
- developing and maintaining key relationships with government officials as well as representatives of key businesses including but not limited to other energy companies;
- supporting procurement opportunities for qualified First Nations and Métis businesses;
- providing engagement services on projects and/or initiatives that potentially affect the First Nations and Métis peoples and communities;
- providing leadership and advice within the company in the building of knowledge and awareness of First Nations and Métis historic and contemporary issues; and
- together with the People and Culture organization, developing initiatives to enhance the level of aboriginal employment at Hydro One.

First Nations and Métis Relations forecast costs are $4.5 million in 2017 and in 2018. The amounts allocated to Hydro One Transmission are $2.6 million annually for 2017 and 2018.

2.4.2 Outsourcing Services

The outsourcing services function manages the contractual relationship with the company's key outsourcing partner in a manner that fosters collaboration and optimizes value and minimizes risk by ensuring that contracted services are delivered. This function is responsible for managing the design, development, and implementation of new service delivery agreements with Hydro One's suppliers.

The outsourcing services' costs are $2.0 million in 2017 and $4.0 million in 2018. The amounts allocated to Hydro One Transmission are $0.7 million in 2017 and $1.8 million for 2018. The increase in 2018 includes anticipated costs associated with retendering Hydro One's biggest outsourcing arrangement.

2.4.3 Corporate Relations

The corporate relations function ensures that Hydro One builds the strategic relationships required to advance its business objectives and presents a single, positive brand internally and externally. It is accountable for corporate reputation, executive support, customer and employee communications, media relations, community investment, web communications and corporate brand identity. The corporate relations function is also accountable for supporting the company's relationships with the government and its key stakeholders. This function leads a "public affairs group" which supports Hydro One's public consultation obligations and community relations programs. This group targets improvements in customer communications regarding power outages while increasing customer education and engagement efforts and research to support improved customer communication.

Costs associated with the corporate relations function are $10.8 million in 2017 and $10.9 million in 2018. The amounts allocated to Hydro One Transmission are $5.4 million and $5.5 million in 2017 and 2018.

2.5 General Counsel and Corporate Secretariat

Table 7 provides an overview of the Hydro One's General Counsel and Corporate Secretariat costs over the 2012-2018 period.

Table 7: General Counsel and Corporate Secretariat Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
General Counsel and Corporate Secretariat	8.8	9.6	9.3	9.3	10.5	10.4	10.5	5.5	5.6

The General Counsel and Corporate Secretariat group provides legal advice and direction to Hydro One and its affiliates, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. It performs the following primary functions:

- ensuring compliance with law and providing legal services relating to all of Hydro One's activities, including the company's major borrowing and financing initiatives, regulatory matters, litigation, transmission and distribution operations, employer-related activities, corporate governance-related matters, and health, safety and environment activities;
- providing corporate secretariat services, which includes supporting the Chair of the Board of Directors, the Board of Directors and its committees and advising on a

variety of board-related matters, such as best practices and emerging trends and issues in the area of corporate governance; and

- providing advice and direction with regard to Hydro One's Code of Conduct, ensuring appropriate actions are taken to resolve known or suspected violations.

The level of required legal and corporate secretarial services is driven by capital and OM&A activities and increasing regulatory and legislative oversight. Most legal work is performed in-house. External legal services are retained when in-house expertise is not available or when the workload exceeds the capacity of the internal legal group.

Hydro One's General Counsel and Corporate Secretariat costs are $10.4 million in 2017 and $10.5 million in 2018. The portion allocated to Hydro One Transmission is $5.5 million in 2017 and $5.6 million in 2018. The increase over historical years is attributable to a heightened complexity in Hydro One's legal matters and a greater volume of work related to procurement, work programs, land acquisition, litigation, and securities compliance.

2.6 Regulatory Affairs

Hydro One's Regulatory Affairs division manages the company's relationships with regulatory bodies such as the OEB, the IESO, and the National Energy Board. It is responsible for developing regulatory strategy and coordinating submissions to these organizations and participating in regulatory initiatives.

Table 8 provides an overview of the Hydro One's Regulatory Affairs costs over the 2012-2018 period.

Table 8: Regulatory Affairs Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Regulatory Affairs	7.4	7.6	8.1	8.7	9.5	10.2	10.0	4.5	4.5
OEB/NEB Costs	13.2	13.1	15.0	15.6	16.3	15.2	15.9	5.1	5.3
Total	**20.6**	**20.6**	**23.1**	**24.4**	**25.8**	**25.4**	**25.9**	**9.6**	**9.8**

The Regulatory Affairs division performs compliance, applications, pricing and load forecasting, and business performance management functions. These functions are described in this section.

The increase in Regulatory Affairs' costs in 2015 and 2016 is primarily attributable to the inclusion of the business performance management costs previously included in Finance costs. (This transition is discussed in in section 2.6.4.) Technology-centric productivity initiatives are expected to decrease costs slightly in the test years, but this decrease is offset by increased staffing needs related to an aggressive regulatory agenda.

2.6.1 Compliance

The regulatory compliance function ensures Hydro One's compliance with the regulations and policies of the OEB, the IESO, and the National Energy Board as they apply to Hydro One's distribution and transmission businesses.

2.6.2 Applications

The applications function coordinates, prepares and processes regulatory applications and provides support to witnesses in regulatory proceedings and business support staff. These services are provided for a wide range of regulatory applications, including distribution and transmission revenue requirement applications, transmission leave–to-construct applications, and applications related to mergers, acquisitions, amalgamations, divestitures and area and system supply planning.

2.6.3 Pricing and Load Forecasting

This function provides pricing and cost allocation analysis and support for rate applications. This work entails developing rates for transmission and distribution tariffs and supporting the preparation and defense of rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

The load forecasting and load data management functions are included within the Regulatory Affairs group. Load forecasts are developed to enable system planning and financial planning which underlie Hydro One's financial forecasts. The load forecast function provides load forecast data including the capture of conservation and demand management impacts. Load forecast staff supports the company’s business units and the IESO with forecasting analysis and evaluation, covering matters such as time of use, bypass and embedded generation. This function also provides analytical support for conservation and demand management projects and provides load research analysis.

2.6.4 Performance Management

In May 2015, the business performance management function moved to the Regulatory Affairs division from the Finance division. This function collects and analyzes data related to the performance of the company and its operations. It provides management with information related to corporate and regulatory scorecards, customer delivery point performance standards, benchmarking and other metrics related to reliability and performance. This function also prepares quarterly and annual reports required under the OEB's *Reporting and Record-keeping Requirements*.

2.6.5 Ontario Energy Board (OEB) / National Energy Board (NEB) Costs

The OEB/NEB costs also include the external costs associated with applications filed with regulatory bodies. Specifically, these costs stem from the provision of notice, stakeholder and consultation activities, provision of expert studies and witnesses, hearing-related expenses, intervenor cost awards, and miscellaneous items like printing and shipping. Over the test period, Hydro One anticipates filing two major revenue requirement applications, several facility applications, as well as filings related to real estate and regional planning efforts.

For this Application, Hydro One has estimated a total cost of $1.3 million, attributing $300,000 to external consultants, $400,000 to the OEB for time spent and notice fees, and $600,000 for intervenor costs.

The OEB/NEB costs also include Hydro One's share of the OEB's costs, including expenses related to the OEB's quarterly assessments, proceedings and intervenor cost awards, and regulatory license assessments.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO and Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include expenses related to staff, office space, administration and overheads. These costs are allocated to one of five categories: electricity distribution, electricity transmission, gas distribution, IESO, and Ontario Power Generation. Hydro One's share of OEB costs is derived from the allocations to electricity distribution and transmission.

2.7 Security Management

Table 9 provides an overview of the Hydro One’s Security Management costs over the 2012-2018 period.

Table 9: Security Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Security Management	3.1	3.4	3.5	4.2	5.1	4.7	4.8	2.2	2.3

The Security Management function exists to enable Hydro One’s success primarily in the protection of assets (including people, property and information), development and maintenance of business continuity and emergency preparedness and response plans and to assist in the reliable delivery of electricity. Security Management adds value by providing advice, coordination, and investigative, technical and intelligence gathering expertise and services to Hydro One staff. This supports the reliable delivery of electricity, the protection of Hydro One’s assets, and the resumption of business in the event of an all-hazards (i.e. natural, technological or human-caused) incident. Effective asset protection and recovery can be the primary differentiating factor between success and failure for Hydro One's business objectives. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance productivity and safety.

Incidents of copper theft have dropped, in part, due to adding security protection systems at heavily targeted transmission sites. However, more organized criminal incidents have occurred in relation to metal thefts, primarily targeting stations that have not benefited from increased capital expenditures for protection systems. Although the total number of incidents has dropped, the average loss per incident is increasing due to the sophistication and organization of these crime groups. These crimes take longer to investigate, and prevention methods and strategies are often very complex and costly.

Security Management costs are forecasted to be $4.7 million in 2017 and $4.8 million in 2018. The amounts allocated to Hydro One Transmission are $2.2 million in 2017 and $2.3 million in 2018.

2.8 Internal Audit & Risk Management

Table 10 provides an overview of the Hydro One's Internal Audit and Risk Management costs over the 2012-2018 period.

Table 10: Internal Audit and Risk Management Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	2013	2014	2015	2016	2017	2018	2017	2018
Internal Audit & Risk Management	3.5	3.4	4.0	4.3	6.0	6.3	6.4	3.3	3.4

The Internal Audit group reports on a functional basis to the Audit Committee of the Board of Directors and administratively to the CFO. It provides independent and objective assurance and consulting services designed to add value to and improve Hydro One's operations. The group's mandate is to provide independent assurance to management of the company and to the Board of Directors that internal controls are designed and operating effectively in areas of material business risk, both financial and non-financial, and to follow-up and report on timeliness and effectiveness of management actions to address findings from past audits.

The Internal Audit group helps Hydro One accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes.

The cost increase in the bridge and test years is the result of two factors. First, rotational resources were made permanent. Costs associated with rotational resources were attributed to the resource's originating department. Once made permanent, these resource costs were reflected fully in Internal Audit costs. Second, there is an increased need for improved Internal Audit capability and capacity due to more stringent governance needs.

Internal Audit costs are forecasted to be $6.3 million in 2017 and $6.4 million in 2018. The amounts allocated to Hydro One Transmission are $3.3 million in 2017 and $3.4 million in 2018.

2.9 Real Estate and Facilities

Table 11 provides an overview of the Hydro One's Real Estate and Facilities costs over the 2012-2018 period.

Table 11: Real Estate and Facilities Costs ($ Millions)

Description	Historic Years				Bridge Year	Test Years		TX Allocation	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2017**	**2018**
Real Estate	8.8	9.3	9.0	8.7	10.2	10.1	10.2	7.6	7.6
Facilities	45.7	44.8	44.6	51.3	49.9	49.5	50.5	24.6	25.1
Total	**54.6**	**54.1**	**53.6**	**60.0**	**60.1**	**59.6**	**60.7**	**32.2**	**32.7**

Real Estate and Facilities OM&A funding for the test years is required for the facilities work program that responds to current and future anticipated Hydro One's work space accommodation needs. This includes new facilities in the field. The facilities work program accounts for approximately 83% of total OM&A funding in test years 2017 and 2018. The funding requirements in the bridge and test years reflect mainly expected increases in fixed operating costs.

2.9.1 Real Estate Services

The real estate services function manages Hydro One's land rights portfolio across the Province. This involves maintaining rights across over 200,000 acres of owned corridor, easement and "statutory right" properties and acquiring any new rights needed to ensure the safe and reliable operation of the transmission and distribution system. In addition, this function oversees the management of Hydro One's rights associated with distribution and transmission lands, stations and other property.

The real estate services function's key work activities include:

- managing the acquisition of new real estate rights, which supports the company's distribution and transmission development and reinforcement project initiatives across the province including those designed to accommodate renewable power sources on the grid;
- managing the provincial secondary land use program on behalf of Ministry of Infrastructure/ Infrastructure Ontario (leasing transmission corridor lands to external parties);
- managing easement, other rights agreements on public/private sector, railway and other lands;
- managing First Nations land use permit settlements on reserve lands;
- managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services; and
- maintaining geographic information system – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions. Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as appropriate.

2.9.2 Facilities

The facilities work program addresses all aspects of company work space requirements. This involves managing company-owned facilities and a portfolio of leased facilities as well as overseeing the construction of new facilities. The work program focuses on providing and maintaining in compliance with laws and applicable codes: (a) storage and garage facilities that meet business requirements, and (b) employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre).

This facilities function is accountable for:

- the management of 50 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes;
- the coordination of activities related to the ongoing management, operation, maintenance and inspection of 90 administrative/service centres, OGCC;
- managing support services for head office space, such as the provision of office supplies, coordinating office moves and providing tenant services; and
- developing accommodation strategies and acquiring new employee/trades workspace in line with operational requirements.

Facilities expenses include, but are not limited to, leasing costs, contract management costs for head office, as well as costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre). A significant portion of the facilities' workload needs are met using outsourcing partners, such as Brookfield Global Integrated Solutions, as described in Exhibit C1, Tab 3, Schedule 2. Facilities costs are largely driven by space needs which are determined by Hydro One's work programs, business and regulatory requirements, and fixed cost contractual obligations.

The majority of the facilities work program costs are fixed. The facilities work program is driven by fixed-cost contractual obligations, which arise primarily through lease agreements. For example, rent, operating and tax costs are fixed by lease agreements. Other costs are set by Hydro One's contracts with service providers for facility maintenance and other services. It is expected that fixed facility cost components (such as utilities, property taxes, operational costs) will continue to rise.

3. OTHER OM&A

Other OM&A expenses are comprised of credits associated with capitalized overhead, environmental provisions, indirect depreciation and other costs as listed in Table 12.

Table 12: Transmission Other OM&A ($ Millions)

Description	**Test**	
	2017	**2018**
Capitalized Overhead	(133.2)	(134.7)
Environmental Provision	(11.6)	(10.0)
Indirect Depreciation	(5.7)	(5.8)
Other	0.8	2.0
Total	**(149.7)**	**(148.5)**

3.1 Capitalized Overhead Credit

Capitalized overheads represent that portion of allocated Common Corporate and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and in the lines of businesses. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch, as described in Exhibit B1, Tab 3, Schedules 9 and 10.

3.2 Environmental Provision

In 2001, Hydro One first recognized a liability on its balance sheet for the present value of the future estimated environmental expenditures needed to manage the risks associated with two legacy environmental issues inherited from Ontario Hydro. These risks pertained to polychlorinated biphenyls and two chemically contaminated lands. Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the Sustainment OM&A work program. The amount is then removed from OM&A as the costs are charged to the balance sheet provision. As well, the offsetting environmental regulatory asset is amortized based on the pattern of expenditure. The resultant impact on revenue requirement of this environmental work is nil, since the amortization expense is grouped with “Depreciation and Amortization” on the operating statement.

3.3 Indirect Depreciation

Transportation and Work Equipment (“TWE”) charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes, it is necessary to remove this depreciation amount from OM&A work programs and appropriately charge it as a depreciation expense. The credit increases in the test years due to the expanded use of TWE in the larger Sustainment, Development and Operations work programs.

3.4 Other Costs

These costs represent material unexpected or non-recurring expenses. For example, they include items such as adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments. For this Application, also included in these costs is the OM&A component of the Employee Share Ownership Program, the Long Term Incentive Program and the union share grants described in Exhibit C1, Tab 4, Schedule 1.

PENSION COSTS

1. INTRODUCTION

Hydro One Networks Inc. ("Hydro One Networks") is a participant in the Hydro One Pension Plan ("the Plan"). The Plan is a contributory, defined-benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), the Society of Energy Professionals ("Society"), non-represented Management ("MCP") employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Plan covers Hydro One and its subsidiaries, except Haldimand Hydro and Woodstock Hydro. The Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for Hydro One Networks, the Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Hydro One Networks' financial statements.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP-2005-0020/EB-2005-0378). Pension costs were similarly approved for Transmission pension costs (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031 and EB-2014-0140); this treatment was continued in Hydro One Distribution's last cost of service application as well (EB-2013-0416).

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost is consistent among all shared services costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378, EB-2006-0501, EB-2007-0681 and EB-2008-0272, EB-2009-0096, EB-2010-0002, EB-2012-0031 and EB-2014-0140.

In 2014 and 2015, actual contributions were $174 million and $177 million, respectively. For the Transmission business, the annual charges sought for recovery through rates for the test years 2017 and 2018 are provided in the Transmission column in table below:

Table 1: Cash Pension Cost (millions, Updated)

2017 Cash pension cost (millions)

Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	18	27	6	52
Capital	$M	33	27		59
	$M	**51**	**54**	**6**	**111**

2018 Cash pension cost (millions)

Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	18	26	6	50
Capital	$M	32	31		63
	$M	**50**	**57**	**6**	**113**

2. ACTUARIAL CALCULATION

The most recent actuarial valuation for the Plan was as at December 31, 2013. In June 2014, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO).

As described in Exhibit C1, Tab 4, Schedule 1, the employee contribution rate to the pension plan has increased and Hydro One engaged Willis Towers Watson to provide an estimate of the resultant savings to the company. These savings are reflected in cash pension costs provided in the table above, as well as the pension expense that is included in Hydro One's operating and capital expenses provided in this application for the test years 2017 and 2018.

Hydro One also engaged Willis Towers Watson to prepare an actuarial valuation as at December 31, 2015, which was finalized in June 2016 and subsequently filed with FSCO. The report is provided as Attachment 1 to this Exhibit. In addition to the recently negotiated changes in employee contribution rates, the valuation also reflects updated investment returns, negotiated changes in employee benefits, and refreshed actuarial assumptions. As anticipated, the valuation demonstrates a further reduction in transmission pension contribution operating expenses of approximately $11 million in 2017 and $8 million in 2018.

Actual contribution requirements in 2017 and 2018 may differ depending on the level of base pension earnings used to compute the monthly contribution. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 1, Schedule 1).

3. PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2015, the Plan had a reported net asset value of $6,746 million and about 13,064 members. About 42% of the Plan's members are active. The remaining Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension or members on long-term disability.

The Fund has consistently outperformed the benchmark made up of passive market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2015, the Fund returned 7.14% annualized while the Fund's target benchmark is 6.92%, thus outperforming its target benchmark return by 0.22%. The fund's investments are divided into asset classes and each asset class has a corresponding market index (i.e. Canadian Equities market index is the S&P/TSX). The actual performance of each asset class is then measured against this market index (policy benchmark). The Fund's policy benchmark is a calculated weighted average benchmark based on the Fund's strategic asset mix.

HYDRO ONE INC.

HYDRO ONE PENSION PLAN

Actuarial Valuation as at December 31, 2015

June 9, 2016

Registration Number: 1059104

Willis Towers Watson

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Introduction

Purpose

This report with respect to the Hydro One Pension Plan has been prepared for Hydro One Inc., the plan administrator, and presents the results of the actuarial valuation of the plan as at December 31, 2015.

The principal purposes of the report are:

- to present information on the financial position of the plan on both going concern and solvency bases;
- to review the hypothetical windup status of the plan;
- to provide the basis for employer contributions; and
- to provide certain additional information required for the administration of the plan.

This report outlines the changes in the plan's financial situation since the previous actuarial valuation at December 31, 2013, provides the information and the actuarial opinion required by the *Pension Benefits Act (Ontario)* and Regulation thereto and provides the information required to maintain plan registration under the *Income Tax Act (Canada)* and Regulations thereto.

This report summarizes the results of the actuarial valuation and contains an actuarial opinion as an integral part of the report. Supporting detailed information on the significant terms of engagement, assets, actuarial basis, membership data and plan provisions is contained in the Appendices.

The information contained in this report was prepared for Hydro One Inc., for its internal use and for filing with the Financial Services Commission of Ontario and the Canada Revenue Agency, in connection with the actuarial valuation of the plan prepared by Towers Watson Canada Inc. ("Willis Towers Watson"). This report is not intended, nor necessarily suitable, for other parties or for other purposes. Furthermore, some results in this report are based on assumptions mandated by legislation. These results may not be appropriate for purposes other than those for which they were prepared. Further distribution of all or part of this report to other parties (except where such distribution is required by applicable legislation or except in accordance with our written agreement with Hydro One Inc.) or other use of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

Significant Events Since Previous Actuarial Valuation

Actuarial Basis

Since the previous actuarial valuation, the assumptions used in the solvency and hypothetical windup valuations have been updated to reflect market conditions at the actuarial valuation date as outlined in Appendix D. In addition, there have been changes to the going concern actuarial basis, as outlined in Appendix C.

Plan Provisions

This actuarial valuation reflects the plan provisions as at December 31, 2015 and does not make any provision for the possibility that a change or action (retroactive or otherwise) may be imposed by order of a regulatory body or a court as we were not aware of any definitive events that would require such change or action at the time this actuarial valuation was completed.

Since the previous valuation, there have been changes to the plan provisions as follows:

- Management employees who were not eligible to elect to become a member of the plan by September 30, 2015 are no longer eligible to join the plan.

- Employee contribution rates were changed as outlined in Appendix F.

- Effective January 1, 2018, a temporary bridge benefit has been added for Society represented employees hired on or after November 17, 2005 as outlined in Appendix F.

These changes had no material impact on the valuation results at December 31, 2015.

Legislative and Actuarial Standards Updates

Since the previous actuarial valuation, the *Standards of Practice for Pension Commuted Values* published by the Canadian Institute of Actuaries effective February 1, 2011 were revised, effective February 1, 2014, to provide for updates to the mortality assumption as promulgated from time to time by the Actuarial Standards Board (ASB). On December 4, 2014 and April 27, 2015, the ASB proposed to promulgate the use of the mortality rates underlying the 2014 Canadian Pensioners Mortality Table (CPM2014) combined with the mortality improvement scale CPM Improvement Scale B (CPM-B) for calculations, effective October 1, 2015. The updated mortality rates have been reflected for purposes of the solvency and hypothetical windup valuations.

Subsequent Events

We completed this actuarial valuation on June 9, 2016.

To the best of our knowledge and on the basis of our discussions with Hydro One Inc., no events which would have a material financial effect on the actuarial valuation occurred between the actuarial valuation date and the date this actuarial valuation was completed.

Section 1: Going Concern Financial Position

1.1 Statement of Financial Position

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Going Concern Value of Assets	$ 6,071,094	$ 5,204,378
Actuarial Liability		
Active and disabled members	$ 2,208,495	$ 2,161,286
Retired members and beneficiaries	3,860,866	3,676,923
Terminated vested members	39,400	33,623
Total	$ 6,108,761	$ 5,871,832
Additional voluntary contribution	20	19
Total Actuarial Liability	$ 6,108,781	$ 5,871,851
Actuarial Surplus (Unfunded Actuarial Liability)	$ (37,687)	$ (667,473)
Prior Year Credit Balance	(48,000)	(48,000)
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance	$ (85,687)	$ (715,473)

Comments:

- The financial position of the plan on a going concern basis is determined by comparing the going concern value of assets to the actuarial liability and is a reflection of the assets available for the benefits accrued in respect of credited service prior to the actuarial valuation date assuming the plan continues indefinitely.

- The prior year credit balance is employer contributions made prior to the actuarial valuation date that are in excess of the minimum required and are set aside as a reserve for application towards future contribution requirements.

- The increase in the defined benefit actuarial liability as at December 31, 2015 that would result from a 1% decrease in the assumed liability discount rate is $953,459,000. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

1.2 Reconciliation of Financial Position

(dollar amounts in thousands)		
Actuarial surplus (unfunded actuarial liability) as at December, 2013 before prior year credit balance		$ (667,473)
Net special payments		177,330
Application of:		
● Actuarial surplus	$ 0	
● Prior year credit balance	0	0
Expected interest on:		
● Actuarial surplus (unfunded actuarial liability)	$ (79,672)	
● Net special payments	10,360	
● Application of actuarial surplus	0	
● Application of prior year credit balance	0	(69,312)
Plan experience:		
● Investment gains (losses)	$ 483,373	
● Salary and YMPE gains (losses)	24,170	
● Cost-of-living adjustment gains (losses)	16,122	
● Retirement gains (losses)	6,603	
● Withdrawal gains (losses)	(17,534)	
● Mortality gains (losses)	6,360	
● Other miscellaneous sources gains (losses)	(8,185)	510,909
Change in actuarial assumptions		$ 10,859
Change in plan provisions		0
Actuarial surplus (unfunded actuarial liability) as at December 31, 2015 before prior year credit balance		$ (37,687)

Comment:

- Actual contributions do not include amounts which were reported as outstanding contributions at the current actuarial valuation date (nor any applicable interest on such outstanding amounts) but include amounts reported as outstanding contributions at the previous actuarial valuation date and contributed prior to the current actuarial valuation date.

1.3 Reconciliation of Prior Year Credit Balance

(dollar amounts in thousands)

Prior year credit balance as at December 31, 2013		$ 48,000
Actual employer contributions:		
• Defined benefit normal actuarial cost	$ 178,102	
• Going concern amortization payments	177,330	
• Solvency amortization payments	0	
• Transfer deficiency payments	0	
• Prior year credit balance	0	
• Other contributions	0	355,432
Minimum employer contributions required:		
• Defined benefit normal actuarial cost	$ (178,102)	
• Going concern amortization payments	(177,330)	
• Solvency amortization payments	0	
• Transfer deficiency payments	0	
• Other contributions	0	(355,432)
Application against unfunded actuarial liability		0
Prior year credit balance as at December 31, 2015		$ 48,000

Section 2: Solvency and Hypothetical Windup Financial Position

2.1 Statement of Solvency Financial Position

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Solvency Value of Assets		
Market value of assets	$ 6,743,615	$ 5,742,219
Provision for plan windup expenses	(16,859)	(14,356)
Total Solvency Value of Assets	$ 6,726,756	$ 5,727,863
Solvency Liability		
Active and disabled members	$ 2,434,330	$ 2,070,880
Retired members and beneficiaries	3,988,651	3,321,439
Terminated vested members	42,265	30,090
Total	$ 6,465,246	$ 5,422,409
Additional voluntary contribution	20	19
Total Solvency Liability	$ 6,465,266	$ 5,422,428
Solvency Surplus (Unfunded Solvency Liability)	$ 261,490	$ 305,435

Comments:

- The financial position of the plan on a solvency basis is determined by comparing the solvency value of assets to the solvency liability (the actuarial present value of benefits accrued in respect of credited service prior to the actuarial valuation date, calculated as if the plan were wound up on that date).
- The solvency actuarial valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- Under an amendment to the Regulation to the *Pension Benefits Act (Ontario)* effective November 26, 1992, the employer had the option to make an election to exclude from the

solvency liability any benefits relating to plant closure and permanent layoff. This plan does not have any such benefits.

- In addition, the Regulation permits certain benefits to be excluded from the solvency liability, without requiring the employer to make an election. Pursuant to the directions from the plan administrator, the value of benefits attributable to future indexation of benefits have been excluded from the solvency valuation. The full defined benefit hypothetical windup liability, taking into account the benefits excluded under the Regulation, is $9,545,090,000 as at December 31, 2015.

- The increase in the defined benefit solvency liability as at December 31, 2015 that would result from a 1% decrease in the assumed liability discount rate is $937,161,000. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

2.2 Hypothetical Windup Financial Position

The hypothetical windup valuation results presented in this report are determined under the same scenario used for the solvency valuation.

If the plan were to be wound up on the actuarial valuation date, the hypothetical windup value of assets would be equal to the solvency value of assets. As permitted by the Regulation to the *Pension Benefits Act (Ontario),* the employer has elected to exclude certain benefits from the solvency liability. The full hypothetical windup liability, taking into account all of the benefits excluded under the Regulation, is $9,545,090,000 as at December 31, 2015. Consequently, the hypothetical windup surplus (unfunded hypothetical windup liability) as at the actuarial valuation date is $(2,818,334,000).

2.3 Solvency Incremental Cost

The solvency incremental cost for a given year represents the present value, at the actuarial valuation date, of the expected aggregate change in the defined benefit solvency liability during the year, increased for expected benefit payments during the year. The solvency incremental cost in respect of each year between December 31, 2015 and December 31, 2018, the next valuation date, are derived from the projection of the solvency liability, as follows:

(dollar amounts in thousands)	2016	2017	2018
Projected solvency liability as at beginning of year	$ 6,465,266	$ 6,544,378	$ 6,615,885
Solvency incremental cost for the year[1]	201,022	201,820	206,268
Interest on projected solvency liability, solvency incremental cost and expected benefit payments	188,686	190,970	193,189
Expected benefit payments during year	(310,596)	(321,283)	(330,710)
Projected solvency liability as at end of year	$ 6,544,378	$ 6,615,885	$ 6,684,633

Note:

[1] These amounts are as at the beginning of the year. The solvency incremental cost, adjusted with interest as at December 31, 2015, is $196,132,000 for 2017 and $194,805,000 for 2018.

2.4 Determination of the Statutory Solvency Excess (Statutory Solvency Deficiency)

The minimum funding requirements under the Regulation to the *Pension Benefits Act (Ontario)* are based on the statutory solvency excess (statutory solvency deficiency) as at the actuarial valuation date. In calculating the statutory solvency excess (statutory solvency deficiency), various adjustments can be made to the solvency financial position including:

- recognition of the present value of existing amortization payments, including any going concern amortization payments established at the actuarial valuation date, due to be paid within the periods prescribed by the Regulation;
- smoothing of the asset value by use of an averaging technique;
- adjustment to the solvency liability by use of an averaging technique in determining the discount rate used to value the liabilities; and
- removal of any prior year credit balance from the asset value.

To the extent that there exists a statutory solvency deficiency, after taking account of these adjustments, additional amortization payments must be made. If there is no statutory solvency deficiency, the statutory solvency excess may be used to reduce the period of any existing solvency amortization payments.

Statutory Solvency Excess (Statutory Solvency Deficiency)

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Solvency surplus (unfunded solvency liability)	$ 261,490	$ 305,435
Adjustments to solvency position:		
• Present value of existing amortization payments	$ 41,929	$ 404,773
• Smoothing of asset value	(672,521)	(537,841)
• Averaging of liability discount rate	345,438	(20,130)
• Prior year credit balance	(48,000)	(48,000)
• Total	$ (333,154)	$ (201,198)
Statutory solvency excess (statutory solvency deficiency)	$ (71,664)	$ 104,237

Comments:

- Further details on the present value of existing amortization payments at December 31, 2015 are provided below.

Details of Present Value of Existing Amortization Payments

(dollar amounts in thousands)

Type of payment	**Effective date**	**Month of last payment recognized in calculation**	**Annual amortization payment**	**Present value as at December 31, 2015 (at 3.40% per annum)**
Going Concern	Dec. 31, 2013	Dec. 2021	$ 9,119	$ 41,929

Section 3: Contribution Requirements

3.1 Contributions for Current Service (Ensuing Year)

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Employer Normal Actuarial Cost		
Estimated contribution	$ 85,632	$ 84,818
Estimated payroll	578,543	523,045
% of payroll	14.8%	16.2%
Estimated Member Contributions	$ 45,183	$ 34,798

Comments:

- The employer defined benefit normal actuarial cost rate changed by (1.3)% of payroll due to the changes in membership profile, by 1.0% of payroll due to changes in actuarial basis and by (1.1)% of payroll due to changes in the plan provisions since the previous actuarial valuation.

- The increase in the employer defined benefit normal actuarial cost rate between the actuarial valuation date and the next actuarial valuation date that would result from a 1% decrease in the assumed liability discount rate, is 7.2% of payroll. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

3.2 Contributions for Past Service

Going Concern Amortization Payments

The unfunded actuarial liability, adjusted for the prior year credit balance, is $85,687,000. The going concern amortization payments from the previous actuarial valuation have been eliminated or reduced such that the present value of the remaining payment schedule is equal to the unfunded actuarial liability. The unfunded actuarial liability must be liquidated by employer amortization payments at least equal to the amounts, payable monthly in arrears, and for the periods set forth below in order to comply with the Regulation to the *Pension Benefits Act (Ontario).*

(dollar amounts in thousands)

Effective date	Month of last payment	Annual amortization payment	Present value as at December 31, 2015 (at 5.40% per annum)
Dec. 31, 2013	Dec. 2028	$ 9,119	$ 85,687

Solvency Amortization Payments

The statutory solvency deficiency revealed at this actuarial valuation is $71,664,000. This statutory solvency deficiency must be liquidated by employer amortization payments at least equal to the amounts, payable monthly in arrears, and for the periods set forth below in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

(dollar amounts in thousands)

Effective date	Month of last payment	Annual amortization payment	Present value as at December 31, 2015 (at 3.40% per annum)
Dec. 31, 2015	Dec. 2020	$ 15,586	$ 71,664

The employer may establish a letter of credit in order to cover all of or a portion of the above amortization payments, to the extent the letter(s) of credit does not exceed 15% of the solvency liabilities.

3.3 Estimated Minimum Employer Contribution (Ensuing Year)

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Employer Normal Actuarial Cost	$ 85,632	$ 84,818
Amortization Payments		
Going concern	$ 9,119	$ 88,665
Solvency	15,586	0
Total	$ 24,705	$ 88,665
Estimated Minimum Employer Contribution[1]	$ 110,337	$ 173,483

Note:

1 Prior to any application of the prior year credit balance.

3.4 Estimated Maximum Employer Contribution (Ensuing Year)

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Employer Normal Actuarial Cost	$ 85,632	$ 84,818
Greater of the Unfunded Actuarial Liability and the Unfunded Hypothetical Windup Liability	2,818,334	2,617,669
Estimated Maximum Employer Contribution	$ 2,903,966	$ 2,702,487

Comment:

- The *Income Tax Act (Canada)* permits the employer to make contributions up to the above amount less the amortization payments made in respect of periods since December 31, 2015, provided that all assumptions made for the purposes of the hypothetical windup valuation remain reasonable at the time each contribution is made. In addition, the maximum employer contribution is to be adjusted with interest for the period between the actuarial valuation date and the date each contribution is made.

3.5 Timing of Contributions

To satisfy the requirements of Ontario pension legislation, the employer normal actuarial cost must be paid monthly and within 30 days of the month to which it pertains while the amortization payments must also be paid monthly but within the period to which they are applicable. Members' contributions must be remitted to the fund monthly and within 30 days of the month to which they pertain.

In addition, within 60 days after this report is filed with the Financial Services Commission of Ontario, the employer must make a special contribution equal to the excess, if any, of:

- the amount of employer contributions (employer normal actuarial cost and amortization payments) that should have been paid after December 31, 2015 according to the minimum contribution requirements revealed by this report (determined with regard to any reported prior year credit balance available to meet these minimum contribution requirements), over

- the actual amount of employer contributions made in respect of periods after December 31, 2015.

Interest must be added to this excess, with such interest determined by reference to the going concern discount rate for payments in respect of employer normal actuarial cost or going concern amortization payments and the solvency discount rate for payments in respect of solvency amortization payments.

To satisfy the requirements of the *Income Tax Act (Canada)*, employer contributions that are remitted to the plan in the taxation year or within 120 days after the end of such taxation year are deductible in such taxation year provided they were made to fund benefits in respect of periods preceding the end of the taxation year.

3.6 Other Statutory Contributions

Additional contributions may be required in respect of the transfer values for members who terminate employment or active plan membership. Where applicable, such additional contributions must be remitted before the related transfer value may be paid in full to the terminated member. Details are provided in Appendix G.

3.7 Future Contribution Levels

Future contribution levels may change as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which have been anticipated at this time. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

Section 4: Actuarial Certification and Opinion

4.1 Actuarial Certification

Based on the results of these actuarial valuations, we hereby certify that, in our opinion, as at December 31, 2015:

- The plan has a prior year credit balance of $48,000,000. The employer may use this prior year credit balance to meet the future contribution requirements of the plan.

- The actuarial surplus (unfunded actuarial liability), determined by comparing the actuarial liability, the measure of obligations of the plan on a going concern basis, to the going concern value of assets, is $(37,687,000).

- The unfunded actuarial liability, adjusted for the prior year credit balance, is $85,687,000 and must be liquidated by employer amortization payments at least equal to the amounts and for the periods set forth in Section 3 in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

- The solvency surplus (unfunded solvency liability), determined by comparing the solvency liability, as defined in the Regulation to the *Pension Benefits Act (Ontario)*, to the solvency value of assets, is $261,490,000.

- The statutory solvency excess (statutory solvency deficiency) revealed at this actuarial valuation is $(71,664,000). This statutory solvency deficiency must be liquidated by employer amortization payments at least equal to the amounts and for the periods set forth in Section 3 in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

- The hypothetical windup surplus (unfunded hypothetical windup liability), determined by comparing the hypothetical windup liability, the measure of the obligations of the plan on a hypothetical windup basis including the value of any potential obligations that may have been excluded for purposes of the solvency valuation, to the hypothetical windup value of assets, is $(2,818,334,000).

- The excess actuarial surplus, pursuant to section 147.2(2) of the *Income Tax Act (Canada)*, is $0.

- The rule for computing the employer defined benefit normal actuarial cost is outlined in the table below. Based on the plan membership used for this actuarial valuation (assuming no new entrants) and the scheduled increases in the employee contribution rates disclosed in the summary of plan provisions, the normal actuarial cost for the next three years is estimated to be:

(dollar amounts in thousands)		**2016**	**2017**	**2018**
Estimated employer normal actuarial cost	$	85,632	79,932	77,446
Estimated payroll		578,543	564,507	554,853
% of payroll		14.8%	14.2%	14.0%
Estimated member contributions	$	45,183	47,870	49,267

The employer is required to make normal actuarial cost contributions to the plan in accordance with the above rule until the effective date of the next actuarial opinion.

- The maximum employer contributions permissible under the *Income Tax Act (Canada)* are described in Section 3.

- The transfer ratio, as defined in the Regulation to the *Pension Benefits Act (Ontario)*, is 0.70. The solvency ratio, defined as the ratio of the solvency value of assets prior to deduction of the provision for plan windup expenses to the solvency liabilities, is not less than 1.00.

- The assessment base determined for the Pension Benefits Guarantee Fund (PBGF) is $0. The PBGF liabilities are $6,465,246,000. Additional liabilities for excluded plant closure benefits, in accordance with section 37(4)(a)(ii) of the Regulation to the *Pension Benefits Act (Ontario)*, are $0.

- In accordance with the Regulation to the *Pension Benefits Act (Ontario)*, the next actuarial valuation should be performed with an effective date not later than December 31, 2018. The basis for employer contributions presented in this report is effective until the next actuarial opinion is filed.

4.2 Actuarial Opinion

In our opinion:

- the membership data on which the actuarial valuations are based are sufficient and reliable for the purposes of the going concern, solvency and hypothetical windup valuations,
- the assumptions are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations, and
- the methods employed in the actuarial valuations are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations.

This report has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada. The actuarial valuations have been conducted in accordance with our understanding of the funding and solvency standards prescribed by the *Pension Benefits Act (Ontario)* and Regulation thereto, and in accordance with our understanding of the requirements of the *Income Tax Act (Canada)* and Regulations thereto. This actuarial opinion forms an integral part of the report.

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

Towers Watson Canada Inc.

David Kenny
Fellow of the Canadian Institute of Actuaries

Suzanne Jacques
Fellow of the Canadian Institute of Actuaries

Toronto, Ontario
June 9, 2016

Appendix A: Significant Terms of Engagement

For purposes of preparing this actuarial valuation report, the plan administrator has directed that:

- The actuarial valuation is to be prepared as at December 31, 2015.
- For purposes of the going concern valuation, the terms of engagement require the use of the margins for adverse deviations mentioned in Appendix C.
- For purposes of determining the going concern liability discount rate, the target asset class distribution is to be established in accordance with the investment policy dated November 12, 2015, which is the most up to date version. There are no expectations that this asset class distribution will be modified in the future.
- For purposes of determining the going concern financial position of the plan, the going concern value of assets is to be determined using the averaging technique described in the Asset Valuation Method section in Appendix C.
- For purposes of determining the solvency liabilities of the plan, the value of benefits arising from future indexation are to be excluded, as permitted by the Regulation to the *Pension Benefits Act (Ontario)*, without requiring an election from the employer.
- For purposes of determining the statutory solvency financial position of the plan, the asset value and liability discount rates are to be determined using the averaging techniques described in the Asset Valuation Method and Rationale for Actuarial Assumptions sections in Appendix D.
- Since to the best of the knowledge of the plan administrator, there is no partial plan windup with an effective date prior to the date of this actuarial valuation, involving members employed in Ontario, not yet completed where the partial windup portion of the plan is in a surplus position on the date of this actuarial valuation, this report is to be prepared on the basis that there will be no retroactive changes to previously filed partial windup reports, if any, and neither the applicable pension regulator nor the plan sponsor will order/declare any partial plan windup with an effective date prior to the actuarial valuation date.
- The solvency and hypothetical windup valuation results presented in this report are to be determined under a scenario where the employer continues to operate and certain expenses are paid from the pension fund (consistent with past practice) while the employer pays other plan expenses.

- This report is to be prepared on the basis that the employer is entitled to apply the actuarial surplus, if any, revealed in an actuarial valuation report to meet its contribution requirements under the plan while the plan remains a going concern, to the extent permitted by applicable pension legislation. (This report does not address the disposition of any surplus assets remaining in the event of plan windup.) If an applicable pension regulator or other entity with jurisdiction directs otherwise, certain financial measures contained in this report, including contribution requirements, may be affected.

Should these directions from the plan administrator be amended or withdrawn, Willis Towers Watson reserves the right to amend or withdraw this report.

Appendix B: Assets

Statement of Market Value

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Total assets	$ 6,745,869	$ 5,743,450
Net additional outstanding amounts:		
• Contributions receivable	$ 0	$ 0
• Benefits payable	(2,254)	(1,231)
• Investment income receivable	0	0
• Total net outstanding amounts	$ (2,254)	$ (1,231)
Total	$ 6,743,615	$ 5,742,219

Comments:

- The invested assets are held by CIBC Mellon under account OHSG10000000.

- The data relating to the invested assets are based on the financial statements issued by KPMG. The data relating to net outstanding amounts were furnished by Hydro One Inc. All such data have been relied upon by Willis Towers Watson following tests of reasonableness with respect to contributions, benefit payments and investment income. However, Willis Towers Watson has not independently audited or verified these data.

Asset Class Distribution

The following table shows the target asset allocation stipulated by the plan's defined benefit component investment policy in respect of various major asset classes and the actual asset allocation as at December 31, 2015.

	Target asset allocation [1]	Asset allocation as at December 31, 2015 [2]
Canadian equities	12%	12%
Foreign equities	38%	47%
Bonds and debentures	33%	34%
Real estate and infrastructure	10%	1%
Cash and short-term investments	2%	4%
Private Equities	5%	2%
Total	100%	100%

Notes:

[1] This information was obtained from the investment policy in effect for the plan as at December 31, 2015. The target asset allocation is expected to remain in effect indefinitely and there are no expectations that the allocation will change in the future.

[2] This information was obtained from Hydro One Inc. All such data have been relied upon by Willis Towers Watson and compared against the target asset allocation to assess reasonableness. However, Willis Towers Watson has not independently audited or verified these data.

Reconciliation of Assets

(dollar amounts in thousands)

Assets as at December 31, 2013		$ 5,743,450
Receipts:		
• Contributions:		
– Employer normal actuarial cost	$ 178,102	
– Employer amortization payments	177,330	
– Employer transfer deficiency payments	0	
– Members' current service contributions	74,173	
– Past service contributions	842	
– Reciprocal transfers	267	
– Provision for non-investment expenses	0	$ 430,714
• Investment return, net of investment expenses		1,283,944
• Total receipts		$ 1,714,658
Disbursements:		
• Benefit payments:		
– Pension payments	$ (579,658)	
– Lump sum settlements	(75,173)	
– Other benefit payments	0	$ (654,831)
• Non-investment expenses		(57,408)
• Total disbursements		$ (712,239)
Assets as at December 31, 2015		$ 6,745,869

Comments:

- This reconciliation is based on the financial statements issued by KPMG. All such data have been relied upon by Willis Towers Watson following tests of reasonableness with respect to contributions, benefit payments and investment income. However, Willis Towers Watson has not independently audited or verified these data.

- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2013 to December 31, 2015 is approximately 10.4% per annum.

Development of the Going Concern Value of Assets

(dollar amounts in thousands)	Adjusted Market Value Beginning from: December 31, 2011	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
Adjusted market value as at December 31, 2011	$ 4,693,703				
Net cash flow for 2012	(98,786)				
Assumed investment return (5.5%)	255,473				
Adjusted market value as at December 31, 2012	4,850,390	$ 5,004,546			
Net cash flow for 2013	(126,979)	(126,979)			
Assumed investment return (5.5%)	263,326	271,805			
Adjusted market value as at December 31, 2013	4,986,737	5,149,372	$ 5,743,450		
Net cash flow for 2014	(106,744)	(106,744)	(106,744)		
Assumed investment return (5.8%)	286,179	295,612	330,068		
Adjusted market value as at December 31, 2014	5,166,172	5,338,240	5,966,774	$ 6,311,204	
Net cash flow for 2015	(117,373)	(117,373)	(117,373)	(117,373)	
Assumed investment return (5.8%)	296,282	306,262	342,717	362,695	
Adjusted market value as at December 31, 2015	$ 5,345,081	$ 5,527,129	$ 6,192,118	$ 6,556,545	$ 6,745,869
Going Concern Value of Assets					
Average of the five adjusted market values as at December 31, 2015					$ 6,073,348
Net outstanding amounts					(2,254)
Going concern value of assets as at December 31, 2015					$ 6,071,094

Comments:

- The asset valuation method is described in Appendix C.
- The rate of return earned on the going concern value of assets, net of all expenses, from December 31, 2013 to December 31, 2015 is approximately 10.2% per annum.

Appendix C: Actuarial Basis – Going Concern Valuation

Methods

Asset Valuation Method

The going concern value of assets was calculated as the average of the market value of assets at the valuation date and the four previous years' adjusted market values. To obtain these adjusted market values, the market values at December 31 of each of the four preceding years were accumulated to the valuation date with net cash flow (i.e., contributions less benefit payments) and assumed investment return. Net cash flow was assumed to occur uniformly throughout each year. Assumed investment return for a year was calculated assuming that each year, the assets earned interest at the going concern discount rate in effect for that year. Finally, this 5-year average of adjusted market values was then adjusted for net additional outstanding amounts.

The objective of the asset valuation method is to produce a smoother pattern of going-concern surplus (deficit) and hence a smoother pattern of contributions, consistent with the long-term nature of a going concern valuation.

Such smoothing is achieved by use of an averaging process which systematically recognizes investment returns different from expectations over a five-year period, with 20% recognized at the valuation date and the remainder at a rate of 20% per year. This method will be expected to average periods of outperformance with periods of underperformance.

The expected return of the going concern discount rate has been selected to equal the expected return on the assets over long periods of time, with a margin for adverse deviations. As such, it is anticipated that, on average, the asset valuation method will tend to produce a result that is somewhat less than the market value of assets.

Actuarial Cost Method

The actuarial liability and the normal actuarial cost were calculated using the projected unit credit cost method.

Prospective benefits were calculated for each active and disabled member according to the plan provisions and actuarial assumptions. The actuarial liability was calculated as the actuarial present value of the member's prospective benefits accrued for credited service to date (the benefit accrual method). The calculation of the actuarial present value of the member's prospective benefits reflects additional entitlements which may arise due to the application of the 50% employer cost-sharing rule, and is at least equal to the member's contributions with interest.

The actuarial liability for retired members and beneficiaries and terminated vested members was calculated as the actuarial present value of their respective benefits.

The employer normal cost for each active and disabled member was determined as the excess of the total normal cost over the member’s required contributions. The normal actuarial cost for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits accruing in respect of credited service in the ensuing year, but not less than the member's required contributions. The employer normal actuarial cost for each active and disabled member was determined as the excess of the total normal actuarial cost over the member's required contributions. The normal actuarial cost rate determined by the projected unit credit cost method will be stable over time if the demographic characteristics of the active and disabled members remain stable from actuarial valuation to actuarial valuation. All other things being equal, a population of active and disabled members whose average age increases (decreases) between actuarial valuations will result in an increasing (decreasing) normal actuarial cost rate.

Additional Voluntary Contributions

For the purposes of the going concern valuation, the determination of the actuarial liability for the additional voluntary contributions does not involve the use of an actuarial cost method, nor does it involve actuarial assumptions. By definition, the actuarial liability under the additional voluntary contributions corresponds with the market value of the members' additional voluntary contribution accounts at the actuarial valuation date.

Actuarial Assumptions

	December 31, 2015	December 31, 2013
Economic Assumptions (per annum)		
Liability discount rate	5.40%	5.80%
Rate of salary increase	2.50% plus merit (see table 1)	2.75% plus merit (see table 1)
Escalation of YMPE under Canada/Québec Pension Plan [1]	3.00%	3.25%
Escalation of *Income Tax Act (Canada)* maximum pension limitation [2]	3.00%	3.25%
Rate of inflation	2.00%	2.25%
Interest on members' contributions	2.00%	Same
Demographic Assumptions		
Mortality	95% of the 2014 Private Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Public Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B, not adjusted for pension size
Withdrawal	Service-related rates (see Table 2a)	Age-related rates (see Table 2b)
Retirement/pension commencement	Age and service related rates (see Table 3a)	Age and service related rates (see Table 3b)
Disability rates	Age-related rates (see Table 4)	Same
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	4
Provision for non-investment expenses	None; return on plan assets is net of all expenses	Same

Notes:

[1] The YMPE of $54,900 for 2016 is the starting value for the YMPE projection as at the current actuarial valuation and is indexed starting in 2016.

[2] The *Income Tax Act (Canada)* maximum pension limit of $2,890 per year of service in 2016 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2016.

Table 1 — Salary Increases due to Movement within the Salary Structure

Age	First 4 Years of Employment	Subsequent Years
under 25	7.0%	1.0%
25 – 29	3.0%	1.0%
30 – 34	3.5%	1.5%
35 – 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 – 49	3.5%	1.5%
50 – 54	2.0%	1.5%
55 – 59	2.0%	1.5%
60 & over	2.0%	0.0%

Table 2a — Current Withdrawal Rates

Service (years)	Male & Female
Under 20	0.01
20 and over	0.00

Table 2b — Sample Prior Withdrawal Rates

Age	Male	Female
15 to 25	0.04	0.05
30 to 35	0.02	0.04
40 to 50	0.01	0.03
over 55	0.00	0.00

Table 3a — Current Retirement Rates

Age	Eligible for Unreduced Retirement Based on points (82 or 85)	Eligible for Unreduced Retirement 35 years of service and over	Not Eligible for Unreduced Retirement
under 55	0.10	0.30	0.00
55 to 59	0.15	0.30	0.05
60 to 64	0.12	0.30	0.07
65	0.50	0.30	0.20
66 to 69	0.25	0.30	0.15
70 and over	1.00	1.00	1.00

Table 3b — Prior Retirement Rates

Age	Eligible for Unreduced Retirement	Not Eligible for Unreduced Retirement Male	Not Eligible for Unreduced Retirement Female
under 55	0.15	0.00	0.00
55 to 60	0.25	0.02	0.05
61 to 64	0.25	0.07	0.10
65	1.00	1.00	1.00

Table 4 — Disability Rates

Age	Male and Female
under 30	0%
30 to 35	0.105%
35 to 40	0.110%
40 to 45	0.115%
45 to 50	0.120%
50 to 55	0.295%
55 to 59	1.000%
60 and above	1.878%

Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the going concern valuation is summarized below.

The going concern assumptions do not include margins for adverse deviations, except as noted below.

Liability discount rate

Actuarial valuation economic assumptions used for establishing the liability discount rate have been developed based on Willis Towers Watson's capital market model. The capital market model simulates economic variables (e.g. inflation and yields) and asset class returns, with the assumptions being developed through both the analysis of historical rates and returns, and the application of econometric theory. In modeling inflation and bond yields, current conditions and long term expectations are used and the serial correlation inherent in these parameters is recognized.

Our long term nominal rate of return assumption was determined using the expected long term asset mix for the plan, which is consistent with the target mix found in the investment policy in effect for the plan as at the actuarial valuation date.

Based on Willis Towers Watson's capital market model, a best estimate long term gross nominal rate of return as of December 31, 2015 of 6.05%. The following adjustments were subsequently made before selecting the discount rate assumption:

● Best estimate long term nominal rate of return before adjustments	6.05%
● Adjustment for investment expenses paid by the plan (excluding active management fees)	(0.04)
● Adjustment for non-investment expenses paid by the plan	(0.10)
● Best estimate long term nominal rate of return after adjustments	5.91%

In the selection of the discount rate, we have assumed that additional returns associated with employing an active investment management strategy would equal the additional expenses associated with employing such strategy. Consequently, we have disregarded any potential additional returns.

After allowing for a 0.54% margin for adverse deviations, we established the discount rate assumption for the plan as 5.40% (rate is rounded to the nearest 10 basis points).

Rate of salary increase and service

The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 0.50% per annum for the effect of real economic growth and productivity gains in the economy. In addition, an allowance has been made for individual employee merit and promotion based on a scale which varies by age and service as shown in this Appendix C. The merit/promotion assumption is based on discussions with Hydro One Inc. management concerning their future expectations.

Escalation of YMPE under Canada/Québec Pension Plan

The YMPE is indexed annually based on increases in the Industrial Aggregate Wage index for Canada. The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Escalation of Income Tax Act (Canada) maximum pension limitation

The maximum pension limitation under the *Income Tax Act (Canada)* is scheduled to be indexed annually based on assumed increases in the Industrial Aggregate Wage index. The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Rate of inflation

The assumption reflects an estimate of future rates of inflation considering economic and financial market conditions at the actuarial valuation date. For the current valuation, the assumed inflation rate is 2.00% per annum. This assumption has been updated since the last actuarial valuation (2.25% per annum) to reflect current long term expectation.

Mortality

The 2014 Private Sector Canadian Pensioners' Mortality Table (CPM2014Priv) is based on a mortality experience study for calendar years 1999 to 2008 conducted by the Canadian Institute of Actuaries on a sample of Canadian registered pension plans. The CPM2014Priv table allows for adjustments to the mortality rates based on pension size and/or industry classification. Improvement Scale B (CPM-B) is a two-dimensional scale developed by the Canadian Institute of Actuaries based primarily on the mortality experience of pensioners under the Canada Pension Plan (CPP) and the Québec Pension Plan (QPP) up to 2007 as well as the assumptions used in the 26th CPP Actuarial Report.

Base mortality rates from the CPM2014Priv table, with a multiplier of 95% based on the plan's actual mortality experience are considered reasonable for the actuarial valuation of the plan. Applying improvement scale CPM-B generationally provides an allowance for improvements in mortality after 2014 and is considered reasonable for projecting mortality experience into the future.

At the previous actuarial valuation, the 2014 Public Sector Canadian Pensioners' Mortality Table projected generationally using CPM-B was used. The mortality table was changed as a result of a review of the actual historical mortality of plan members over the period 2007-2015.

Withdrawal

The rates of withdrawal were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations.

The rates of withdrawal at the last actuarial valuation were developed based on a review of plan experience, performed by Mercer (Canada) Limited, for the years 2000 to 2006.

Percentage of involuntary terminations of employment

No allowance has been made for involuntary terminations of employment on the basis that the impact of including such an assumption and valuing statutory grow-in rights would not have a material impact on the actuarial valuation results.

Disability incidence/recovery

The rates of disability incidence/recovery are based on a prior assessment performed by Mercer (Canada) Limited. The use of a different assumption would not have a material impact on the actuarial valuation results.

Retirement from active membership

The rates of retirement were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations. All members are assumed to commence their pension at their retirement date.

The rates of retirement at the last actuarial valuation were developed based on a review of plan experience, performed by Mercer (Canada) Limited, for the years 2000 to 2006.

Pension commencement after termination of employment

All terminated members are assumed to commence their pension at the age that produces the highest liability value based on the plan’s subsidized early retirement reductions applicable to terminated members commencing their pension prior to normal retirement age.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

When provided, the actual data for the spouse and form of payment were used for retired members. For other members, the assumed percentage of members with a spouse is based on the percentages for the general population and an assessment of future expectations for members of the plan.

Years male spouse older than female spouse

When provided, the actual data for the spouse were used for retired members. For other members, the assumption is based on surveys of the age difference in the general population, a review of plan data for the years 2006 to 2015, and an assessment of future expectations for members of the plan.

This assumption has been updated from 4 years at the last valuation to 3 years at the current valuation.

Provision for non-investment expenses

The liability discount rate is net of all expenses. The assumed level of expenses reflected in the liability discount rate is based on recent experience of the plan and an assessment of future expectations.

Appendix D: Actuarial Basis – Solvency and Hypothetical Windup Valuations

Methods

Asset Valuation Method

The market value of assets, adjusted for net outstanding amounts, has been used for the solvency and hypothetical windup valuations. The resulting value has been reduced by a provision for plan windup expenses.

The adjustment in respect of the smoothing of solvency assets for purposes of determining the statutory solvency deficiency was calculated as the difference between the actuarial value of assets used for the going concern valuation and the market value of assets.

Liability Calculation Method

The solvency and hypothetical windup liabilities were calculated using the traditional unit credit cost method.

The solvency and hypothetical windup liabilities for active and disabled members were calculated as the actuarial present value of all benefits accrued up to the actuarial valuation date. This calculation reflects additional entitlements which may arise due to the application of the 50% employer cost-sharing rule, and is at least equal to the member's contributions with interest.

The solvency and hypothetical windup liabilities for retired members and beneficiaries and terminated vested members were calculated as the actuarial present value of their respective benefits.

Other Considerations

The solvency and hypothetical windup valuations have been prepared on a hypothetical basis. In the event of an actual plan windup, the plan assets may have to be allocated between various classes of plan members or beneficiaries as required by applicable pension legislation. Such potential allocation has not been performed as part of these solvency and hypothetical windup valuations.

Additional Voluntary Contribution

For the purposes of the solvency and hypothetical windup valuations, the determination of the liability for the additional voluntary contributions does not involve the use of a liability calculation method, nor does it involve actuarial assumptions. By definition, the solvency and hypothetical windup liability under the additional voluntary contributions corresponds with the market value of the members' additional voluntary contribution accounts at the actuarial valuation date.

Solvency Incremental Cost Actuarial Method

The solvency incremental cost for a given year represents the present value, at the actuarial valuation date, of the expected aggregate change in the defined benefit solvency liability during the year, increased for expected benefit payments during the year.

The solvency incremental cost reflects expected decrements and related changes in membership status, accrual of service, any expected changes in benefits, entitlements, members' contributions, pension formula or increases in the maximum pension limits, and projected pensionable earnings during the year.

The solvency incremental cost has been calculated for each year until the next actuarial valuation date as the projected solvency liability at the end of the year, minus the solvency liability at the beginning of the year, increased for expected benefit payments during the year. Each of these amounts is discounted to the actuarial valuation date using the projected solvency liability discount rate.

The method used to calculate the projected solvency liabilities at each projection year is the same as used in the solvency valuation.

Actuarial Assumptions

	December 31, 2015	December 31, 2013
Economic Assumptions (per annum)		
Liability discount rate (before averaging for solvency and for hypothetical windup)		
• Annuity purchase (non-indexed)	3.10%	3.90%
• Annuity purchase (fully-indexed)	-0.05%	0.15%
• Annuity purchase (partially-indexed) [1]	0.74%	1.10%
• Commuted value (non-indexed)	2.10% for 10 years, 3.70% thereafter	3.00% for 10 years, 4.60% thereafter
• Commuted value (fully-indexed)	1.30% for 10 years, 1.80% thereafter	1.70% for 10 years, 2.30% thereafter
• Commuted value (partially-indexed) [1]	1.50% for 10 years, 2.30% thereafter	2.00% for 10 years, 2.90% thereafter
Liability discount rate (after averaging for solvency)		
• Annuity purchase	3.58%	3.85%
• Commuted value	2.52% for 10 years, 3.96% thereafter	3.08% for 10 years, 4.54% thereafter
Discount rate for determining amortization payments [2]	3.40%	3.70%
Escalation of *Income Tax Act (Canada)* maximum pension limitation [3]	1.16% for 10 years, 2.20% thereafter	1.46% for 10 years, 2.43% thereafter
Demographic Assumptions		
Mortality	CPM2014 Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	1994 Uninsured Pensioner Mortality Table, projected generationally using Scale AA
Withdrawal	N/A	Same
Disability incidence/recovery	N/A	Same
Retirement/pension commencement	Described in detail on page D-8	Same

	December 31, 2015	**December 31, 2013**
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	4
Percentage of members receiving settlement by commuted value [4]	Retired members and beneficiaries: 0% Other members: ● not eligible for retirement: 70% ● eligible for retirement: 40%	Same
Provision for expenses		
● Solvency	0.25% of assets	Same
● Hypothetical windup	0.25% of assets	Same

Notes:

[1] Applicable to New Society and New Management members only.

[2] Equal to the liability-weighted average of the liability discount rates for settlements by commuted value transfer (rate in effect for the first 10 years) and annuity purchase.

[3] The *Income Tax Act (Canada)* maximum pension limit of $2,890 per year of service in 2016 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2016.

[4] The balance are assumed to receive settlement by annuity purchase.

Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the solvency and hypothetical windup valuations is summarized below.

The actuarial assumptions used in the solvency and hypothetical windup valuations do not include margins for adverse deviations.

Liability discount rate

Discount Rates for Solvency (before averaging) and Hypothetical Windup

In the event of a plan windup, it is expected that a portion of the liabilities will be settled by a group annuity purchase and the balance of the liabilities will be settled by commuted value transfers.

For the calculation of the portion of the solvency and hypothetical windup liabilities relating to the benefits that are expected to be settled by a group annuity purchase, the liability discount rate corresponds to an approximation of the annuity purchase rates as at the actuarial valuation date following application of the relevant guidance on assumptions for solvency and hypothetical windup valuations issued by the Canadian Institute of Actuaries' Committee on Pension Plan Financial Reporting. The guidance provides that the approximation of the annuity purchase rate varies in accordance with the duration of the liabilities for non-indexed benefits assumed to be settled by group annuity. The duration of the liabilities assumed to be settled through the purchase of non-indexed annuities is 11.8.

For the calculation of the portion of the solvency and hypothetical windup liabilities relating to the benefits that are expected to be settled by commuted value transfers, the liability discount rates have been determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the valuation date. For this actuarial valuation, the December 2015 rates have been used.

Discount Rates for Solvency (after averaging)

- The average discount rates for calculation of the statutory solvency deficiency are based on the following: Benefits that are expected to be settled by a group annuity purchase:

  The average of the annualized approximate annuity purchase rates at December 31, 2015 and the four previous year-ends [1], determined as follows:

December 31, 2011	3.79%
December 31, 2012	3.44%
December 31, 2013	4.38%
December 31, 2014	3.18%
December 31, 2015	3.10%
Average	3.58%

Note:

[1] The approximate annuity purchase interest rates prior to October 1, 2015 have been adjusted to reflect the change in the mortality table assumption applicable to the determination of liabilities settled by group annuity purchase.

- Benefits that are expected to be settled by commuted value transfers:

The average of the interest rates determined under the *Standards of Practice for Pension Commuted Values,* published by the Canadian Institute of Actuaries, at December 31, 2015 and the four previous year-ends[1], determined as follows:

	Rate for 10 years	Rate after 10 years
December 31, 2011	2.60%	4.10%
December 31, 2012	2.40%	3.60%
December 31, 2013	3.00%	4.60%
December 31, 2014	2.50%	3.80%
December 31, 2015	2.10%	3.70%
Average	2.52%	3.96%

Note:

[1] The *Standards of Practice for Pension Commuted Values* effective on December 31, 2015 are assumed to have always been in effect when determining the interest rates prior to October 1, 2015.

Escalation of Income Tax Act (Canada) maximum pension limitation

The maximum pension limitation under the *Income Tax Act (Canada)* is scheduled to be indexed annually based on assumed increases in the Industrial Aggregate Wage index. This assumption has been determined as the underlying inflation rates from the rates applicable to benefits expected to be settled by commuted value transfers (after averaging for solvency). For simplicity, this assumption has also been used for the benefits that are expected to be settled by a group annuity purchase.

Mortality

For the benefits that are expected to be settled by a group annuity purchase, the assumption has been set following application of the relevant guidance on assumptions for solvency and hypothetical windup valuations issued by the Canadian Institute of Actuaries' Committee on Pension Plan Financial Reporting.

For benefits that are expected to be settled by commuted value transfers, the assumption has been determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the valuation date. No pre-retirement mortality has been assumed in order to approximate the value of pre-retirement death benefits.

Retirement/pension commencement

For active and disabled members:

- Members eligible to retire: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).

- Members with age plus continuous service greater than or equal to 55 years and employed in Ontario or Nova Scotia: pension commences at the age that produces the highest actuarial value of pension (including statutory grow-in rights).

- Other members: pension commences at the age that produces the highest actuarial value

For deferred vested members:

- Members are assumed to retire at the earliest age at which they qualify for an unreduced pension.

For the benefits that are expected to be settled by a group annuity purchase, this is consistent with the expected assumption that will be used by insurers to price the group annuity. For benefits that are expected to be settled by commuted value transfers, this assumption is in accordance with the Canadian Institute of Actuaries' *Standards of Practice for Pension Commuted Values*.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

See rationale for going concern assumptions in Appendix C.

Years male spouse older than female spouse

See rationale for going concern assumptions in Appendix C.

Percentage of members receiving settlement by commuted value transfer

This assumption has been determined by considering the benefit provisions of the plan, legislative requirements to offer specific settlement options to various classes of members, and, in particular, the options to be provided to members upon plan windup.

The assumption also reflects the expectation that members further from retirement are more likely to elect to settle their pension benefit by a commuted value transfer, while members closer to retirement are more likely to elect to settle their pension benefit through a group annuity purchase where this option is available.

Provision for expenses

Allowance was made for normal administrative, actuarial, legal and other costs which would be incurred if the plan were to be wound up (excluding costs relating to the resolution of surplus or deficit issues). The actuarial valuation is premised on a scenario in which the employer continues to operate after the windup date. In establishing the allowance for plan windup costs, certain administrative costs were assumed to be paid from the pension fund (consistent with past practice) while other costs were assumed to be borne directly by the employer.

Solvency Incremental Cost Actuarial Assumptions

Demographic and Benefit Projection Actuarial Assumptions

Except as noted below, the projected population, benefits and members' contributions valued in the solvency liability projection are based on the demographic and benefit projection assumptions used for the going concern valuation described in Appendix C.

New entrants

An allowance has been made for new entrants for the Post-Society and PWU groups only, between the current actuarial valuation date and next actuarial valuation date. The new entrants profile is assumed to be similar to the profile of average new entrants in the plan over the years 2008-2012. We have assumed no new entrants under the management group as new management employees are not entitled to join this plan. Membership in the PWU and Society groups is assumed to remain stable over the projection period.

Solvency Liability Projection Actuarial Assumptions

The solvency liability projections for purposes of calculating the solvency incremental cost are based on the assumptions used for the solvency valuation described previously.

Appendix E: Membership Data

Summary of Membership Data

Active members

	December 31, 2015	December 31, 2013
• Number	5,355	5,360
• Average age	44.1	44.1
• Average credited service	13.3	13.5
• Annual payroll	$ 543,523,888	$ 512,892,395
• Average salary	$ 101,498	$ 95,689
• Accumulated contributions with interest	$ 367,013,623	$ 344,471,267

Disabled Members

	December 31, 2015	December 31, 2013
• Number	131	127
• Average age	54.9	55.4
• Average credited service	23.4	24.3
• Annual payroll	$ 11,169,636	$ 10,152,527
• Average salary	$ 85,264	$ 79,941
• Accumulated contributions with interest	$ 9,230,244	$ 9,175,783

Comment:

- The following distribution relates to active and disabled members. The following meanings have been assigned to age, credited service and earnings:

The following distribution relates to active and disabled members. The following meanings have been assigned to age, credited service and earnings:

- Age — Age as at December 31, 2015
- Credited Service — Credited service as at December 31, 2015
- Earnings — Annual rate of earnings as at December 31, 2015

Active and Disabled Members

		Credited Service								
Age		*0 - 4*	*5 - 9*	*10 - 14*	*15 - 19*	*20 - 24*	*25 - 29*	*30 - 34*	*35 +*	*Total*
< 25	Number	46								46
	Average Earnings	74,940								74,940
25 - 29	Number	415	172							587
	Average Earnings	85,769	90,794							87,241
30 - 34	Number	323	590	32						945
	Average Earnings	88,106	95,815	114,408						93,810
35 - 39	Number	143	335	142	20					640
	Average Earnings	92,827	97,906	107,524	102,732					99,056
40 - 44	Number	78	255	131	34	8	3			509
	Average Earnings	97,414	102,273	105,756	116,031	100,737	98,400			103,297
45 - 49	Number	40	191	97	26	76	146	1		577
	Average Earnings	106,298	102,621	108,600	**	108,667	108,173	**		106,603
50 - 54	Number	46	191	126	46	79	513	97	7	1,105
	Average Earnings	109,043	101,154	106,285	111,880	106,073	108,513	107,856	108,970	106,920
55 - 59	Number	32	116	78	23	43	174	138	75	679
	Average Earnings	92,248	101,065	104,731	127,487	105,011	106,521	115,495	114,327	108,011
60 - 64	Number	12	53	36	24	10	66	50	60	311
	Average Earnings	**	105,610	102,315	109,172	127,285	106,862	100,450	101,895	104,340
65 +	Number	2	16	16	2	3	16	19	13	87
	Average Earnings	**	113,429	98,493	**	171,735	114,443	**	119,733	114,551
Total	Number	1,137	1,919	658	175	219	918	305	155	5,486
	Average Earnings	89,603	98,532	106,592	113,393	108,438	108,033	110,891	109,726	101,111

Average Age = 44.3   Average Credited Service = 13.5

** For confidentiality

Retired members

	December 31, 2015	December 31, 2013
• Number	5,502	5,445
• Average age	71.5	71.1
• Total annual pension	$ 240,389,865	$ 215,558,746
• Average annual pension[1]	$ 43,691	$ 39,588
• Total temporary annual pension	$ 24,642,237	$ 25,163,484

Beneficiaries and survivors

	December 31, 2015	December 31, 2013
• Number	1,777	1,793
• Average age	80.4	79.9
• Total annual pension	$ 44,098,256	$ 41,483,088
• Average annual pension	$ 24,816	$ 23,136
• Total temporary annual pension	$ 460,627	$ 487,347

Terminated vested members

	December 31, 2015	December 31, 2013
• Number	294	292
• Average age	53.5	53.2
• Total annual pension[2]	$ 2,872,957	$ 2,543,201
• Average annual pension	$ 9,772	$ 8,710

Notes:

1 Excluding temporary annual pension.

2 Prior to application of Income Tax Act maximum pension limits.

Review of Membership Data

The membership data were supplied by Hydro One Inc.'s third-party administrator, Morneau Shepell, as at December 31, 2015.

The membership data have been relied upon by Willis Towers Watson following tests for reasonableness and found to be sufficient and reliable for the purposes of the actuarial valuation. Elements of the data review included the following:

- ensuring that the data were intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain whether the complete membership of the plan appeared to be accounted for;
- preparation and review of age and service distributions for active and disabled member for reasonableness;
- review of consistency of individual data items and statistical summaries between the current actuarial valuation and the previous actuarial valuation;
- review of reasonableness of individual data items, statistical summaries and changes in such information since the previous actuarial valuation date; and
- comparison of the membership data and the plan's financial statements for consistency.

However, the tests conducted as part of the membership data review may not have captured certain deficiencies in the data. We have also relied on the certification of the plan administrator as to the quality of the data.

Membership Reconciliation

	Actives	Disabled	Terminated vested	Retired	Beneficiaries and survivors	Total
As at December 31, 2013	5,360	127	292	5,445	1,793	13,017
• New entrants (including re-employed)	485	0	0	0	0	485
• From disabled	6	(6)	0	0	0	0
• To disabled	(34)	34	0	0	0	0
• Terminated (with lump sum payment)	(71)	(2)	(8)	0	0	(81)
• Termination (with vested pension entitlement)	(34)	0	34	0	0	0
• Retirement	(349)	(18)	(22)	389	0	0
• Deceased (without beneficiary)[1]	0	0	0	(148)	(215)	(363)
• Deceased (with beneficiary)	(7)	(4)	0	(184)	195	0
• New ex-spouse	0	0	0	0	4	4
• Data corrections	(1)	0	(2)	0	0	(3)
• Net change	(5)	4	2	57	(16)	42
As at December 31, 2015	5,355	131	294	5,502	1,777	13,059

[1] Includes pensioners whose guarantee period has expired.

Appendix F: Summary of Plan Provisions

The following is an outline of the principal features of the plan which are of financial significance to valuing the plan benefits. This summary is based on the most recently restated plan document as at January 1, 2000 and amendments up to and including the valuation date, as provided by Hydro One Inc., and does not make any provisions for the possibility that a change or action (retroactive or otherwise) could be imposed by order of a regulatory body or a court. It is not a complete description of the plan terms and should not be relied upon for administration or interpretation of benefits. For a detailed description of the benefits, please refer to the plan document.

Membership

The following categories of employees are members of the Pension Plan:

a) All regular employees (see Note 1a and Note 1b);

b) Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982;

c) Continuing construction employees who were members admitted to the Ontario Electricity Financial Corporation Pension Plan and its predecessors;

d) Employees who became continuing construction clerical employees after July 29,1982 and before August 8, 1984;

e) Employees who have completed three months of continuous employment as a probationary employee (see Note 1a and Note 1b).

Note 1a: Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 are eligible after completing three months of continuous employment but are not required to join the Pension Plan.

Note 1b: Management employees who were not eligible to elect to become a member of the Pension Plan on or after September 30, 2015 are no longer eligible to join the Pension Plan.

Any other employee who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the Year’s Maximum Pensionable Earnings (“YMPE”), as defined under the Canada Pension Plan in each of the two previous consecutive calendar years, may elect to become a member of the Pension Plan.

Normal Retirement Date

a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her 65th birthday.

b) All other members: The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

a) 2% of the member's "high three-year average" (see Note 5) for each year of credited service, subject to a maximum of 35 years (see Note 2).

Note 2: For Management employees hired on or after January 1, 2004, and Society represented employees hired on or after November 17, 2005 the reference to "high three-year average" is changed to "high five-year average" for pensionable service while a Management or Society-represented employee.

LESS

b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 5) for each year of credited service included in (a) above subsequent to December 31, 1965, subject to a maximum of 35 years – see Note 3.

Note 3: Effective July 1, 2001, for members of the PWU, and effective January 1, 2004, for Society represented members hired before November 17, 2005; the factor is reduced from 0.625% to 0.50%.

Bridge Pension (see Note 4)

0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 5) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

The bridge benefit is reduced for early retirement in accordance with the same early retirement reduction provision applicable to the early retirement life pension described below.

Note 4: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, no bridge pension is payable for pensionable service *while a Management or Society-represented employee. Effective January 1, 2018, Society represented employees hired on or after November 17, 2005 will be entitled to a bridge benefit equal to 0.625% up to the average YMPE for each year of service from January 1, 2018 onward while the member is earning a benefit under the basic formula.*

Note 5: "High three-year average"/ "high five-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the 36/60 consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the 60 consecutive months when the base earnings were highest.

Early Retirement

Age Plus Service (See Note 7)

A member may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the member's age and years of continuous employment is equal to or greater than 82 or the member has 35 years of continuous employment, whichever occurs first (see Note 6).

Note 6: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, retirement without reduction is available when the sum of the employee's age and years of pensionable service is equal to or greater than 85 or the employee has 35 years of pensionable service, whichever occurs first.

25 or More Years of Continuous Employment (see Note 7)

A member who does not qualify for the early retirement provisions above who is at least age 55 and has 25 or more years of continuous employment may retire prior to age 60, in which case the member's accrued pension is reduced by 3% for each year by which early retirement precedes age 60. These reductions also apply to members who elected a deferred pension when they left the Pension Plan and had 25 or more years of continuous employment.

Female Members with More Than 15 Years or Other Members with 15 or More Years but Less than 25 Years of Continuous Employment (see Note 7)

A female member whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other member with 15 or more years but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the member's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the member's normal retirement date.

These reductions apply with respect to a female member whose employment commenced prior to 1976 and who has a deferred pension and at least 25 years of continuous employment at retirement. For any other members who have a deferred vested pension and have fewer than 25 years of continuous employment and are at least age 55 when they request that the pension payments begin, the deferred vested pension will be actuarially reduced (unless the member was eligible for an unreduced early retirement provision in effect when the member terminated active employment).

Other Members

A member, who does not qualify under any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. If the retirement occurred prior to July 1, 2012, the member is also required to have at least two years of Pension Plan membership. In such a case, the pension is the actuarial equivalent of the member's deferred pension provided that the reduction shall not be less than the minimum early retirement reduction required under the *Income Tax Act* (Canada).

Terminated Members with Deferred Pensions

A terminated member with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination. In addition, if the member's employment is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the *Pension Benefits Act* (Ontario) ("PBA"), resulting in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination.

Note 7: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 all references to "continuous employment" are to be replaced with "pensionable service" for service while a Management or Society-represented employee.

Postponed Retirement

Members who work past their normal retirement date shall continue to accrue benefits until December 1st of the calendar year they reach age 71 (or the Income Tax Act age limit, if different), they reach the 35 year service limit, or they terminate employment, whichever occurs first. If a member reaches 35 years of service and ceases contributions to the Pension Plan, service after 35 years is not counted in the calculation of the member's pension, but the pension is calculated using the member's base earnings up to the date of postponed retirement. If the member works past age 71, the member's pension will commence to be paid not later than December 1st of the year in which the member turns age 71.

Pension Increases

Pension increases of 100% (see Note 8) of the increase in the Consumer Product Index ("CPI") (Ontario), for the 12-month period ending in June of the previous year , will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions to an annual maximum of 8% each year after 1999. Any excess will be carried forward to use in future years up to the 8% limit.

Note 8: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, pension increases of 75% CPI (Ontario) for the 12-month period ending in June of the previous year will be given every January 1, to an annual maximum increase of 5%, with no carry forward.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Employee Contributions

Members, not represented by the Society or PWU, contribute at the following rates until they complete 35 years of credited service:

On and after April 1, 2015,

i. 6.25% of base annual earnings up to the YMPE; and
ii. 8.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired on or after November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 9):

Up to and including March 31, 2016,

i. 6.50% of base annual earnings up to the YMPE; and
ii. 8.50% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

i. 7.00% of base annual earnings up to the YMPE; and
ii. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 7.75% of base annual earnings up to the YMPE; and
ii. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired before November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 9):

Up to and including March 31, 2016,

iii. 6.50% of base annual earnings up to the YMPE; and

iv. 8.50% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

iii. 7.00% of base annual earnings up to the YMPE; and

iv. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

iii. 7.75% of base annual earnings up to the YMPE; and

iv. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018

iii. 8.75% of base annual earnings up to the YMPE; and

iv. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Note 9: For Society represented members hired before November 17, 2005, contributions increase by 0.5% in the event that after January 1, 2004 a valuation report reveals that the solvency assets are lower than 106% of the solvency liabilities. Effective April 1, 2018 this clause is no longer applicable.

Members represented by the PWU contribute at the following rates until they complete 35 years of credited service:

Up to and including March 31, 2016,

i. 7.25% of base annual earnings up to the YMPE; and

ii. 9.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 8.75% of base annual earnings up to the YMPE; and

ii. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Death Before Retirement

No Surviving Spouse or Eligible Dependent Children

Fewer than two years of Pension Plan membership (Deaths prior to July 1, 2012)

The member's beneficiary or estate receives a cash refund of the member's contributions plus interest.

Two or more years of Pension Plan membership

The beneficiary or estate will receive the following:

- For pre-1987 service: a cash refund of the member's contributions plus interest.
- For post-1986 service: a lump sum equal to the commuted value of the member's pension earned since 1986, plus a refund of any excess contributions.

For deaths occurring on or after July 1, 2012, the beneficiary or estate will be entitled to the death benefits described above regardless of the member's length of service.

Surviving Spouse (see Note 10)

Fewer than two years of Pension Plan membership and less than 10 years of continuous employment

The beneficiary or estate receives a cash refund of the member's contributions plus interest.

Fewer than two years of Pension Plan membership and more than 10 years of continuous employment

The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned to the date of death.

More than two years of Pension Plan membership, but less than 10 years of continuous employment

For pre-1987 service: The beneficiary or estate receives a cash refund of the member's contributions plus interest.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or

b. an immediate or deferred pension with a commuted value equal to pension earned after 1986.

More than two years of Pension Plan membership, and more than 10 years of continuous employment

For pre-1987 service: The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned prior to 1987.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or

b. an immediate or deferred pension with a commuted value equal to pension earned after 1986. The immediate pension will not be less than 66.67% of the pension earned after 1986.

Note 10: For deaths occurring on or after July 1, 2012, the surviving spouse's entitlement to death benefits for post-1986 service shall be determined without reference to whether the member had more or less than two years of Pension Plan membership. In addition, for deaths occurring on or after July 1, 2012, if the surviving spouse is entitled to the death benefits in respect of the member's post-1986 service, the surviving spouse is also entitled to an amount equal to the member's contributions, with interest, in respect of pre-1987 service, rather than the designated beneficiary or estate.

<u>Dependent Children, No Surviving Spouse</u>

If the member completed 10 years of continuous employment, the survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. A payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, being an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse, subject to other options chosen at the time of retirement. If the survivor spouse subsequently dies and is survived by the dependent children, or the member does not have a surviving spouse and is survived only by dependent children, the 66.67% survivor pension is split among the dependent children and is payable to age 18 (longer if disabled or in full-time attendance at a school or university).

If the member does not have a surviving spouse at retirement, the normal form of pension is a pension payable for life with a guarantee of 60 payments.

Optional forms of pension are available on an actuarially equivalent basis.

Termination of Employment (see Note 12)

Less Than One Year of Pension Plan Membership

A cash refund of the member's contributions plus interest.

More Than One Year But Fewer Than Two Years of Pension Plan Membership

The member is entitled to elect a cash refund of the member's contributions plus interest, or may leave the earned pension benefit in the Pension Plan to be paid upon retirement.

More Than Two Years but fewer than 10 Years of Pension Plan Membership and, either under Age 45, or Fewer Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to a cash refund of the member's contributions plus interest, or may leave all of the earned pension benefit in the Pension Plan until retirement.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More Than Two Years but fewer than 10 Years of Pension Plan Membership, and Age 45 or Older with More Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) 75% of the commuted value of the pension and receive a refund of 25% of the commuted value of your earned pension; or to leave 75% of the earned pension benefit in the Pension Plan until retirement, and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More Than 10 Years of Pension Plan Membership, But Younger Than Age 45

For service from 1965 to 1986: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More than 10 Years of Pension Plan Membership and Age 45 or Older

For pre-1965 service: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value.

For service from 1965 to 1986: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value; or to transfer (see Note 11) the greater of the commuted value of 75% of the earned pension or the member's contributions with interest and receive a refund of 25% of the commuted value of the earned pension.

For post 1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer the commuted value of the earned pension.

If a member is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the PBA, which could result in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination. If grow-in benefits apply, this may affect the value of the benefits the member is entitled to receive on termination of employment or retirement.

Note 11: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Note 12: In respect of terminations occurring on or after July 1, 2012, a member is entitled to the earned pension benefits for all service regardless of length of Pension Plan membership, continuous employment or age.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the vested deferred pension accrued after 1986 is refunded to the member (or to the spouse, beneficiary or estate, as applicable in the case of death before retirement).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987. (See Note 13)

Note 13: For terminations occurring on or after July 1, 2012, entitlement to excess contributions in respect of pre-1987 service shall be determined without reference to age or years of continuous employment.

Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act (Canada).

Appendix G: PBGF Assessment, Transfer Ratio and Solvency Ratio

PBGF Assessment

(dollar amounts in thousands)		**December 31, 2015**
PBGF Assessment		
Solvency liability:		
• Total	$	6,465,246
• Ontario PBGF liability		6,465,246
• Ontario additional PBGF liability		0
Solvency value of assets:		
• Total	$	6,743,595
• Ontario PBGF assets		6,743,595
PBGF assessment base	$	0
Plan membership (including inactive members):		
• Total		13,059
• Ontario		13,059

Comments:

- The solvency value of assets reflects net outstanding amounts. The solvency value of assets is prior to deduction of a provision for plan windup expenses.
- For the purposes of calculating the PBGF assessment base, the solvency value of assets and the solvency liability exclude the additional voluntary contribution provision.
- The Ontario PBGF liability used for purposes of calculating the PBGF assessment excludes the Ontario additional PBGF liability.
- As specified in the Regulation to the *Pension Benefits Act (Ontario)*, the additional PBGF liability is the additional solvency liability for plant closure and permanent layoff benefits excluded for those Ontario members who are immediately eligible for the benefit at the actuarial valuation date, if any.

Transfer Ratio and Solvency Ratio

(dollar amounts in thousands)		December 31, 2015
Transfer Ratio		
Solvency value of assets	$	6,743,615
Lesser of estimated employer contributions for the period until the next actuarial valuation and prior year credit balance	$	48,000
Hypothetical windup liability	$	9,545,090
Transfer ratio		0.70
Solvency Ratio		
Solvency value of assets	$	6,743,615
Solvency liability	$	6,465,266
Solvency ratio		Not less than 1.00

Comments:

- The solvency value of assets reflects net outstanding amounts. The solvency value of assets is prior to deduction of a provision for plan windup expenses.
- As the transfer ratio is less than 1.00, transfer deficiencies must be paid over a maximum period of five years unless the cumulative transfer deficiencies are within the limits prescribed by the Regulation to the *Pension Benefits Act (Ontario)* or the employer remits additional contributions in respect of the transfer deficiencies. Pursuant to Regulations 19(4) or 19(5) to the *Pension Benefits Act (Ontario)*, approval of the Superintendent will be required to make commuted value transfers if there has been a significant decline in the transfer ratio after the actuarial valuation date.
- Based on the solvency ratio defined as the ratio of solvency value of assets to solvency liabilities, the next actuarial valuation of the plan is due with an effective date not later than December 31, 2018.

Appendix H: Certificate of the Plan Administrator

I hereby certify that to the best of my knowledge and belief:

- the significant terms of engagement contained in Appendix A of this report are accurate and reflect the plan administrator's judgement of the plan provisions and/or an appropriate basis for the actuarial valuation of the plan;
- the information on plan assets, including the information on the investment policy and intended changes to the asset mix distribution after the valuation date, if any, forwarded to Towers Watson Canada Inc. and summarized in Appendix B of this report is complete and accurate;
- the data forwarded to Towers Watson Canada Inc. and summarized in Appendix E of this report are a complete and accurate description of all persons who are members of the plan, including beneficiaries who are in receipt of a retirement income, in respect of service up to the date of the actuarial valuation;
- the summary of plan provisions contained in Appendix F of this report is accurate; and
- there have been no events which occurred between the actuarial valuation date and the date this actuarial valuation was completed that may have a material financial effect on the actuarial valuation.

[signature]	6/6/16
Signature	Date
Michael Vels	Chief Financial Officer
Name	Title

Appendix I: Actuarial Information Summary

COMMON CORPORATE COSTS, COST ALLOCATION METHODOLOGY

Allocation of Common Corporate Costs to Hydro One's Distribution and Transmission businesses and to each Hydro One affiliate is based on clearly articulated shared functions and services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Customer Service, Planning, Information Technology, and Operating Programs to support the Hydro One Networks' Distribution and Transmission businesses. CCF&S are described fully in Exhibit C1, Tab 3, Schedule 3 and include Corporate Management, Finance, Human Resources, Corporate Communications & Services, General Counsel & Secretariat, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate & Facilities.

1. ALLOCATION METHODOLOGY

Since 2004, in connection with each cost of service application, Hydro One has commissioned a study by Black and Veatch (B&V) to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The 2015 report on this study is provided as Attachment 1 to this exhibit.

As part of the 2015 study, the cost drivers used to allocate the common corporate costs in EB-2014-0140 were updated to incorporate current information.

A time study was conducted within Hydro One's Planning, Operating and Customer Service groups. The time study for these groups spanned a four week period.

Hydro One accepted the results of the 2015 B&V study as providing a reasonable and equitable approach to the assignment of common corporate costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

2. 2017-2018 ALLOCATED AMOUNTS

The following Tables 1 to 2 provide the annual allocation of 2017-2018 CCF&S costs, respectively to all business units.

1 **Table 1: Allocation of 2017 CCF&S Costs ($ Millions)**

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Remotes	Hydro One Inc.
Corporate Management	22.3	7.2	6.8	0.1	0.1	8.1
Finance	41.0	21.9	17.9	0.9	0.3	0.1
Human Resources	14.8	7.6	6.8	0.2	0.1	0.0
Corporate Communications & Services	17.3	8.7	8.5	0.0	0.1	0.0
General Counsel & Secretariat	10.4	5.5	4.4	0.1	0.3	0.1
Regulatory Affairs	25.4	9.6	15.0	0.0	0.1	0.8
Corporate Security	4.7	2.2	2.5	0.0	0.0	0.0
Internal Audit	6.3	3.3	2.8	0.1	0.1	0.0
Real Estate & Facilities	59.6	32.2	27.3	0.0	0.0	0.0
Total CCF&S Costs	201.8	98.3	92.0	1.4	1.1	9.1

Table 2: Allocation of 2018 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Remotes	Hydro One Inc.
Corporate Management	22.1	7.1	6.7	0.1	0.1	8.1
Finance	38.6	19.5	17.9	0.9	0.3	0.1
Human Resources	14.2	7.3	6.6	0.2	0.1	0.0
Corporate Communications & Services	19.4	9.9	9.4	0.0	0.1	0.0
General Counsel & Secretariat	10.5	5.6	4.5	0.1	0.3	0.1
Regulatory Affairs	25.9	9.8	15.3	0.0	0.1	0.8
Corporate Security	4.8	2.3	2.5	0.0	0.0	0.0
Internal Audit	6.4	3.4	2.9	0.1	0.1	0.0
Real Estate & Facilities	60.7	32.7	27.9	0.0	0.0	0.0
Total CCF&S Costs	202.7	97.6	93.7	1.4	1.1	9.0

REVIEW OF ALLOCATION OF COMMON CORPORATE COSTS (TRANSMISSION) – 2015

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

4 MAY 2016

BLACK & VEATCH
Building a world of difference.

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I. Summary

A. BACKGROUND

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report which describes our Review of Allocation of Common Corporate Costs (Transmission)- 2015 ("2015 Review").

In 2004, Black & Veatch was engaged by Hydro One to recommend a best practice methodology to distribute Common Corporate Costs to Hydro One and its subsidiaries and partnership (identified in Table 2). Common Corporate Costs are the costs to provide certain functions and services (identified in Table 3), including those performed by Inergi LP, to Hydro One and its subsidiaries and partnership. Black & Veatch recommended, Hydro One adopted, and the Ontario Energy Board ("OEB") accepted, a methodology to distribute those costs, as described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Common Costs Report").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with subsequent reports issued, as follows:

Table 1 - History of Black & Veatch's Cost Allocation Reviews for Hydro One

BLACK & VEATCH REVIEW	BUSINESS PLAN	BLACK & VEATCH REPORT
2006 Review	BP 2007-2011	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	BP 2009-2013	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	BP 2010-2014	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	Updated BP 2010-2014	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010
2012 Review	BP 2012-2016	*Review of Shared Services Cost Allocation (Transmission) – 2012* dated February 1, 2012
2013 Review	BP 2014-2019	*Review of Allocation of Common Corporate Costs (Distribution) – 2013* dated September 19, 2013
2014 Review	BP 2014-2019	*Review of Allocation of Common Corporate Costs (Transmission) – 2014* dated March 17, 2014

The OEB-accepted methodology to distribute the Common Corporate Costs has been applied by Hydro One to its Business Plan for 2017-2018 ("BP 2017-2018") data. This Report describes the "2015 Review" that Black & Veatch performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2017-2018 in connection with its 2017-2018 Transmission rates application, and presents Black & Veatch's conclusions.

B. HYDRO ONE ORGANIZATION

Hydro One Inc. operates through the wholly-owned subsidiaries and partnership listed in Table 2. The OEB regulates, separately, the business units identified as such in Table 2. Each regulated business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

Table 2 – Hydro One Business Units

SUBSIDIARY	BUSINESS UNIT	REGULATED	DESCRIPTION
Hydro One Networks Inc.	Distribution	Yes	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.3 million customers.
	Transmission	Yes	Owns and operates substantially all of Ontario's electricity transmission system.
Hydro One Remote Communities Inc	Remotes	Yes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
Hydro One Telecom Inc.	Telecom	No	Sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.
Hydro One Inc.	Holding	Yes	Subsidiary of Hydro One Ltd. Acts as the holding company of Hydro One's rate regulated businesses.
Hydro One Ltd.	Holding	No	Public company that owns Hydro One Inc. for the transmission and distribution rate regulated businesses and Hydro One Telecom Inc. for non-regulated business activity. Hydro One Ltd. is owned by public shareholders as well as the Province of Ontario.
B2M Limited Partnership	B2M Transmission Line	Yes	Continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching station.

C. FUNCTIONS AND SERVICES IN COMMON CORPORATE COSTS

Hydro One provides the functions and services identified in Table 3, to the businesses identified in Table 2. Exhibit A further describes the functions and services provided. The BP 2017-2018 includes 2017 Common Corporate Costs totaling approximately $325 million incurred to perform the relevant functions and services; and the annual total Common Corporate Costs are presented in Table 4.

Approximately 37% of the Common Corporate Costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). Common Corporate Costs includes the cost included in BP 2017-2018 for sustainment activities outsourced to Inergi services pertaining to infrastructure/data centre support services, application management services, disaster recovery services, end-user services, desk-side management services and service management.

Table 3 - Functions and Services in Common Corporate Costs

Hydro One Inc. Corporate Office ■ President/CEO Office ■ Chair ■ CFO's Office ■ Treasurer's Office ■ Board of Directors ■ Corporate Secretariat ■ General Counsel – VP ■ Pension Cost ■ Donations ■ Ombudsman Office ■ Investor Relations	**Shared Services** ■ Real Estate ■ Value Growth **CFO's Office** ■ Treasury ■ Corporate Controller ■ Taxation ■ Regulatory Affairs ■ Business Planning & Decision Support
Operations ■ Distribution Asset Management (Note 1) ■ Planning and Optimization (Note 1) ■ Reliability, Strategies, and Compliance (Note 1) ■ System Planning (Note 1) ■ Network Connections and Development (Note 1) ■ Network Operations (Note 1) ■ Transmission Asset Management (Note 1) ■ VP Planning (Note 1) ■ EVP Office – Operations (Note 1) ■ Outsourcing Services ■ Strategic Services	**Customer and Corporate Relations** ■ Customer Care Services (Note 1) ■ Customer Strategy and Conservation (Note 1) ■ Customer Program Delivery (Note 1) ■ Key Account Management (Note 1) ■ VP Customer Service (Note 1) ■ Meter to Bill (Note 1) ■ Corporate Affairs ■ First Nations and Métis Relations ■ Bad Debt and Goodwill ■ SVP Customer and Corporate Relations
Information Services ■ Corporate Projects ■ Information Technology ■ Security Operations	**Inergi LP (outsourced services)** ■ Finance ■ Human Resources - Pay Services ■ Accounts Payable
People and Culture	**General Counsel & Secretariat**
Audit	**VP Chief Risk Officer**
Note 1- Department participated in 2015 Time Study; see Section V.	

D. BLACK & VEATCH'S ASSIGNMENT

For the 2015 Review, our assignment was to:

a. Evaluate whether the existing Common Corporate Cost Allocation Methodology continues to be appropriate for Hydro One, and identify changes that are necessary or desirable.

b. Review Hydro One's application of the OEB-accepted Common Corporate Cost Allocation Methodology to the BP 2017-2018, in connection with its 2017-2018 Transmission rates application.

The organization presented in Table 3 reflects the creation of new departments, realignment of departments among groups, and realignment of functions among departments, that Hydro One believes will allow it to serve its customers most effectively and efficiently, based on the current business and regulatory environment.

The Common Corporate Costs Model for BP 2017-2018 reflects these organizational changes. Black & Veatch reviewed the cost driver for each activity to determine its continued applicability, and where necessary, the development of the cost driver was updated to reflect the organizational changes.

Concurrently with this 2015 Review, Black & Veatch reviewed and issued reports on Hydro One's Overhead Capitalization Rate methodology, Common Assets allocation and Allocation of Common Corporate Costs to the Bruce-to-Milton (B2M) Limited Partnership.

E. OVERVIEW OF METHODOLOGY

The Black & Veatch methodology for allocating the costs of Hydro One's Common Corporate Costs was designed to address the following considerations:

- Compliance with OEB precedent including Docket RP-2002-0133 (*In The Matter Of The Ontario Energy Board Act, 1998)*
- Compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters ("Code")
- Cost incurrence- Are the costs needed to perform services required by the business units?
- Cost allocation- Are costs appropriately allocated among business units, based on the application of cost drivers /allocation factors supported by principles of causality?
- Cost/benefit- Do benefits received equal or exceed the cost?

An overview of the Black & Veatch cost allocation methodology is described below:

- Identify the functions and services included in Common Corporate Costs.
- Identify activities that are performed to provide those functions and services.
- Based on time and/or cost studies, distribute the annual departmental costs in the BP 2017-2018 among the activities performed by that department in providing the functions and services.
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when direct assignment is not possible.

- The guiding principle used by the Black & Veatch methodology to assign cost drivers is cost causation.

A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. Cost drivers are discussed in Section D. The different types of cost drivers are described in Exhibit B.

F. SCOPE OF WORK

Consistent with Black & Veatch's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and factual accuracy, but without our independent confirmation. All dollar amounts in this Report are stated in Canadian dollars.

G. CONCLUSIONS AND RESULTS

Black & Veatch believes that Hydro One's current cost allocation methodology continues to be appropriate for Hydro One because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice) and promotes transparency and efficiency.

Based on our review, Black & Veatch concludes that the results of Hydro One's application of the Black & Veatch Common Corporate Cost Allocation Methodology to its BP 2017-2018 data reflects a cost causation-based distribution of the Common Corporate Costs and conforms to the OEB-accepted methodology. The annual results for years 2017-2018 are shown in Table 4.

Black & Veatch also notes that Hydro One management believes that the existing methodology is appropriate for the company, the cost allocation process receives strong support from Hydro One management and is well integrated into the budgeting process and the Common Corporate Costs Model is updated periodically to reflect current information.

Table 4 presents the results of Hydro One's distribution of the Common Corporate Costs in BP 2017-2018, annually for 2017-2018, among its Distribution, Transmission and Other businesses.

Table 4 - Distribution of Annual Common Corporate Costs

Business	2017	2018
($ Millions)	**$**	**$**
Transmission	$ 163	$ 162
Distribution	$ 150	$ 150
Other	$ 12	$ 12
Total	**$ 325**	**$ 324**
(% of Total)	**%**	**%**
Transmission	50%	50%
Distribution	46%	46%
Other	4%	4%
Total	**100%**	**100%**

II. Statement of Approach

This section presents the approaches used by Black & Veatch to evaluate whether the existing Common Corporate Cost Allocation Methodology continues to be appropriate for Hydro One, and to review Hydro One's application of the methodology to the BP 2017-2018 costs of providing the functions and services included in Common Corporate Costs.

A. EVALUATE COST ALLOCATION METHODOLOGY

The Common Corporate Cost Allocation Methodology was first applied to Hydro One's Business Plan 2006-10. Hydro One requested that Black & Veatch evaluate whether the methodology is still appropriate, and what changes, if any, could be considered. Black & Veatch's approach is discussed in detail in Section III.

B. REVIEW APPLICATION OF COST ALLOCATION METHODOLOGY

In preparing the 2015 Review, Black & Veatch performed the following tasks:

Task 1. Reviewed Hydro One's current organizational structure and identified departments that perform the functions and services included in Common Corporate Costs.

Task 2. Identified the activities performed by each department in order to provide the functions and services identified in Task 1.

Task 3. Determined the Common Corporate Costs in BP 2017-2018 to perform the functions and services in Task 1.

Task 4. Identified the business units that use the functions and services included in Common Corporate Costs.

Task 5. Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2017-2018 for departments identified in Task 1, among the activities identified in Task 2.

Task 6. Directly assigned activity costs to business units where a direct relationship exists.

Task 7. For activities where less than all of the BP 2017-2018 costs were directly assigned to business units in Task 6, assigned a cost driver that reflects cost causation.

Task 8. Populated the cost drivers.

Task 9. Reviewed the 2015 Time Study.

Task 10. Computed total Common Corporate Costs allocated to each business unit.

Task 11. Performed analytical review of results.

Task 12. Reviewed the Common Corporate Costs used to perform the computations.

C. PRINCIPLES OF COST ALLOCATION

There are two methods to allocate or distribute shared costs among a utility's business units – Direct Assignment and Allocation. *Direct Assignment* is used when it can be reasonably determined that all or a portion of an activity is performed for a particular business unit. Direct Assignment is completed through the use of time studies or time surveys; where participants either fill out a daily time sheet or provide an indication of how their time is spent throughout the year. Approximately 75% of Common Corporate Cost in the BP 2017-2018 was assigned directly to one or more of Hydro One's business units.

Allocation is used when more than one business unit uses an activity, but the portions of the activity that each uses cannot be directly established through a time study or time survey. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred. The principles used by Black & Veatch to assign cost drivers are discussed in Section II.D below.

D. COST DRIVERS

As stated above, a cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred. The guiding principle that Black & Veatch uses in assigning cost drivers is cost causation. Cost causation means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which case selecting cost drivers based on benefits received is a fair alternative treatment.

Other factors considered in assigning cost drivers include:

- Practicality – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- Stability – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.
- Materiality – When choosing between cost drivers, small differences can often be ignored in favor of Practicality and Stability (see above).

E. TYPES OF COST DRIVERS

Cost drivers can be classified as External or Internal. *External* drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts.

Internal drivers are based on values computed as an integral part of the cost allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities. Exhibit B further describes the different types of cost drivers.

III. Evaluate Cost Allocation Methodology

The Common Corporate Cost Allocation Methodology was first applied to Hydro One's BP 2006-10. Black & Veatch has also reviewed the application of the methodology to subsequent business plans, as listed in Section I.A. The purpose of this portion of the 2015 Review was to evaluate if the methodology is still appropriate, including reviewing changes that were recommended in the past.

Based on our discussions with Hydro One personnel and review of the Common Corporate Costs Model, Black & Veatch determined that the cost allocation methodology continues to be appropriate for Hydro One because:

- It meets best practices since it distributes costs based on cost causation, including the use of direct assignment when possible, and then through the use of cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management, and is understood and accepted by the Hydro One business units.
- It allows the business units to determine precisely what amounts they are charged by department and by activity within the department; this transparency provides a basis for understanding the nature of the charges and value of the services received.
- It is well-integrated with Hydro One's annual Business Planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization, and the Common Corporate Costs Model can be adapted easily to reflect those changes.

Black & Veatch believes that the current cost allocation methodology continues to be appropriate for Hydro One, because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice), and promotes transparency and efficiency.

IV. Review Application of Methodology to BP 2017-2018

In this Section we will discuss each of the Tasks performed in the Scope of Work, as stated in Section B. This includes the purpose of the Task, the steps performed, the source of the information, and the results.

Task 1. Reviewed Hydro One's current organizational structure and identified departments that perform the functions and services included in Common Corporate Costs.

The purpose of this Review was to evaluate the allocation of the Common Corporate Costs among the businesses that use the functions and services.

The organization of Hydro One Inc. is described in Section I.B. The functions and services support the Distribution business and the Transmission business, and the other businesses listed in Table 2. The departments that perform the functions and services in Common Corporate Costs are listed in Table 3. Exhibit A further describes the functions and services. This information was provided by Hydro One in discussions and documents.

Task 2. Identified the activities performed by each department in order to provide the functions and services identified in Task 1.

The purpose of this task was to identify the activities that are performed in order to provide each of the functions and services.

Functions and services (identified in Task 1) are performed for the benefit of the business units. Activities (discussed in this Task 2) are the tasks performed in order to provide the functions and services. Activities are measured in the amount of resources used.

To distribute the resources required to provide the functions and services included in Common Corporate Costs among the business units on the basis of cost causation, the activities performed were identified and described by Hydro One to Black and Veatch.

Task 3. Determined the Common Corporate Costs in BP 2017-2018 to perform the functions and services in Task 1.

In this task, we obtained the BP 2017-2018 costs for the departments that provide the functions and services included in Common Corporate Costs. Hydro One provided to Black & Veatch the labour and non-labour portions of the BP 2017-2018 for each of these departments, as well as descriptions of major non-labour cost items.

Task 4. Identified the business units that use the functions and services included in Common Corporate Costs.

The business units that use the functions and services included in Common Corporate Costs are listed in Table 2. The information was provided by Hydro One and confirmed by the service recipients.

Task 5. Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2017-2018 for departments identified in Task 1, among the activities identified in Task 2.

The purpose of this task was to distribute the resources (time for labour and costs for non-labour and Inergi) required for each of the functions and services identified in Task 1, among the activities identified in Task 2. In subsequent tasks, the cost of each activity was either directly assigned to one or more business units or allocated using cost drivers.

Labour costs

To distribute budgeted labour costs, Hydro One department managers determined the portion of annual time spent by the personnel under their supervision on each of the activities identified in Task 2. Some managers based their estimates on concurrent time records that they maintain, some conducted interviews with their personnel, and some used their informed judgment. Some of the holding company's labour cost was allocated consistent with previous rate filings. The information provided by the managers was reviewed by Hydro One and Black & Veatch and was found to be reasonable and consistent with prior distributions of resources.

Non-labour costs

Budgeted non-labour costs items were examined and distributed based on direct assignment or allocation; this amount includes non-labour costs of departments in the 2015 Time Study. This included OEB invoices, communications programs, insurance costs and claims, human resources programs, labour relations programs, actuarial consultants and audit fee. The balance of non-labour costs includes items such as training and development, non-specific expenses and general expenses.

Inergi costs

The Common Corporate Costs representing functions and services provided by Inergi were distributed among the activities, based on information provided by Hydro One, assignments and allocations by Hydro One and Black & Veatch, and the application of judgment by Hydro One and Black & Veatch. The approach for each of the functions and services provided by Inergi is described below. Exhibit A describes these services in greater detail.

- **Finance –** Costs were assigned among activities based on estimated portion of total amount paid to Inergi to perform the function. Activities were allocated among the business units based on chosen cost drivers that relate to each activity (e.g., Fixed Asset Accounting activity was allocated on Gross Utility Plant).
- **Human Resources –** Costs were assigned among activities based on estimated effort by Inergi. All activities were allocated among the business units based on headcount.

Task 6. Directly assigned activity costs to business units

The purpose of this task was to assign, among the business units listed in Task 4, the resources (time for labour resources and costs for non-labour and Inergi resources) for each activity listed in Task 2. This task was performed concurrently with Task 5 – Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2017-2018 for departments identified in Task 1, among the activities identified in Task 2.

For the activities listed in Task 2, Hydro One's departmental managers distributed the resource costs among one or more business units, based on the business units that caused the costs to be incurred. When possible, all or a portion of costs were assigned to a specific business unit.

Task 7. Any portion of an activity that was not assigned to a specific business unit due to its generalized nature was allocated among business units using cost drivers, as described in Task 7. Assigned cost drivers

As discussed above, the costs of activities were directly assigned to business units when possible. The purpose of this task was to select cost drivers for the portion of costs which were not directly assigned in Task 6.

The principles that Black & Veatch used to assign cost drivers are discussed in Section II.D- Cost Drivers. Black & Veatch selected cost drivers based on applying the principles discussed above, its experience in performing cost allocation studies, consultations with Hydro One as to the nature of each activity, and industry practices and regulatory requirements.

Section II.E Types of Cost Drivers describes the types of cost drivers.

Table 5 summarizes the direct assignments and types of costs drivers used to distribute the Common Corporate Costs among the business units. Amounts include the Inergi charges.

Table 5 - Direct Assignments and Cost Drivers for Common Corporate Costs

TYPE	2017	2018
(% of Total)	%	%
Direct Assignment	62.07%	61.18%
Physical	9.78%	9.87%
Financial	22.59%	23.04%
Internal	5.56%	5.91%
Total	100.00%	100.00%

Task 8. Populated cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to each business unit in order to distribute the costs of each activity among the business units. The supporting information was provided by Hydro One.

Task 9. Reviewed 2015 Time Study

This Task is discussed in Section V.

Task 10. Computed total common corporate costs for each business unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6, and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the activity cost to be allocated by the cost driver value for the business unit.

Task 11. Performed analytical review

The purpose of this task was to compare the results of the distribution of the BP 2017-2018 Common Corporate Costs among the business units to the results in the previous 2014 Review, and to understand the differences.

The proportions of the total cost distributed to each business unit have been reasonably similar over time and differences are explained by additions and removal of departments from the Common Corporate Costs (i.e., the 2015 Review included Bad Debt and Goodwill which is 100% Distribution, for the first time), changes in allocations of time, changes in allocator values and changes in departmental functions and activities.

Task 12. Reviewed Common Corporate Costs Model

The purpose of this task was to review the Common Corporate Costs Model that Hydro One has developed for allocating the Common Corporate Costs, to determine if it properly reflects and models the OEB-approved cost allocation methodology for those costs included in the BP 2017-2018.

Black & Veatch first reviewed Common Corporate Costs Model in connection with our 2008 Review, and has reviewed the model for each of the subsequent reviews performed, including this 2015 Review. The model is updated periodically to reflect organizational changes; Business Plan costs; additions to and deletions of departmental activities; time and cost distributions among activities; assignments of allocators; and cost driver values.

The Common Corporate Costs distributes departmental costs among activities (Task 6) and then distributes the cost of each activity based on direct assignments or cost drivers (Task 10).

Based on Black & Veatch's review, the Common Corporate Costs properly implements the OEB-accepted methodology for distributing the costs of corporate functions and services in the BP 2017-2018, and continues to produce a cause-based allocation of costs.

V. 2015 Time Study

Hydro One employees representing approximately $115 million of annual labour costs participated in a time study for the four-week period ending June 12, 2015 (“2015 Time Study”).

The departments that participated in the 2015 Time Study are identified in Table 3 (designated by Note 1 next to the department name). The responsibilities of these departments are included in Exhibit A.

The personnel in these departments are able to determine with reasonable accuracy, on a current basis, the time they spend on Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects because the programs and projects on which they work are clearly defined.

A properly performed time study measures cost causation and is widely accepted as a basis for assigning costs. Hydro One personnel administered the 2015 Time Study using the same design and communication material designed by Black & Veatch and utilized in the time study that occurred in 2013. Black & Veatch’s responsibilities included reviewing time study results and the consolidation of the results, and confirming the completeness of the time study and its consistency with the study design. The methodology was the same as used in prior time studies conducted by Black & Veatch for Hydro One.

It was not practical to perform a full-year study, but we believe the results for a four-week period are representative of the full-year. To support this judgment, Black & Veatch reviewed the previous Hydro One time studies, which were completed at different times during the year, and found that the results were reasonably similar to the 2015 Time Study results.

Black & Veatch found that the 2015 Time Study was appropriately designed and completed, the results were correctly compiled, and the methodology was the same as for prior Hydro One time studies performed in connection with Black & Veatch’s previous cost allocation reviews. Therefore, Black & Veatch concluded that the 2015 Time Study results were a proper basis for assigning the costs of the departments included in the study between Hydro One’s Distribution and Transmission business units.

Exhibit A: Functions and Services in Common Corporate Costs

FUNCTIONS AND SERVICES	DESCRIPTION
Hydro One Inc. Corporate Office (HOI)	
President / CEO Office	Leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develop and update strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
CFO's Office	Provide Hydro One and subsidiaries with strategic review and approval for all financial and investment decisions. Review policies and procedures, treasury operations and tax planning, financial control and reporting.
Treasurer's Office	Debt and equity issuance, capital structure management and oversight of Finance- Treasury function.
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
Corporate Secretariat	Provide direction and analysis in areas of: Board and Committee(s); Office of Chair and Board members; Code of Business Conduct; Community Citizenship; Freedom of Information and Privacy, Corporate Archives, Corporate Records, Corporate Secretariat.
General Counsel- VP	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Pension Cost	Pension fund contributions.
Donations	Includes donations to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way and local community causes. Costs are directly assigned to Shareholder only.
Ombudsman Office	The Ombudsman Office commenced activity following the Initial Public Offering, in order to address complaints escalated from the Customer Service . Prior to that, the Province of Ontario's Ombudsman had authority to investigate issues related to Hydro One customers.
Investor Relations	Investor Relations commenced activity following the Initial Public Offering, in order to communicate with Shareholders and potential investors and address their concerns.
Shared Services	
Real Estate	Manage and acquire rights of way and easements; manage property taxes; manage SLU revenue programs; manage Employee Relocation Program.
Value Growth	Seeks ways to leverage Hydro One's core competencies to increase overall value and drive down average cost to serve. Costs are directly assigned to Shareholder only.

FUNCTIONS AND SERVICES	DESCRIPTION
CFO's Office	
Treasury	Risk management including insurance purchasing; insurance claims settlement; financial risk management; cash & banking operations; debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders; funds management; investor relations-shareholders, creditors, equity analysts & rating agencies; support business activities; project management.
Corporate Controller	Corporate Accounting & Reporting; Revenue Management; Financial Modeling & Analysis; Accounting Policy; Internal Control; IFRS / US GAAP; Inergi Finance; Bill 198; Corporate Compliance.
Taxation	Meet internal and external tax compliance requirements and reduce overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, HST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes and government tax audits.
Regulatory Affairs	Coordinate applications with OEB; compliance with OEB orders; design and implement regulatory policy; manage relationship with OEB. Tasks include: cost allocation and rate design for regulated Tx and Dx, especially rate structures and rates for Tx and Dx tariffs; implement approved rates; support transmitters' representative on IESO Technical Panel; manage MV Star to support settlement. Includes: Direct billed OEB costs for Tx and Dx; Direct billed NEB costs for Tx; Costs of Rate Hearings before the OEB for Tx and Dx.
Business Planning and Decision Support	Financial modeling & analysis; corporate planning & reporting; regulatory finance; decision support to the lines of business
Operations	
Distribution Asset Management	Create prioritized, defensible distribution system investment strategies and plans to meet Hydro One's Corporate Strategic Objectives including promoting innovation and automation of our grids consistent with maximum customer value. This includes the Distribution Technology roadmap and smart meter deployment including communications infrastructure.
Planning and Optimization	Coordinate the investment planning and investment approvals processes for projects and programs issued to the lines of business from the Planning Business Unit. The investment plan is developed and maintained through the use of various tools, reports and LoB interaction.
Reliability, Strategies, and Compliance	Promote and facilitate Hydro One's engagement and participation in the development of reliability standards and related IESO Market Rules; Develop, communicate and assist with the implementation of policies,

FUNCTIONS AND SERVICES	DESCRIPTION
	directives, procedures, and processes to ensure an enduring compliance posture with reliability standards.
System Planning	Develop and commit prioritized, defensible transmission development plans, consistent with corporate strategy, to meet government policy, OPA plans, customer needs, regulatory requirements and industry standards. Conduct Regional Infrastructure Planning to meet OEB requirements and to develop regional plans to meet regional supply needs.
Network Connections and Development	Facilitate the connection of new load and generation customers to Hydro One's transmission network, supporting customers' objectives while respecting Hydro One's strategic objectives and resource requirements.
Network Operations	Operates the largest electricity delivery system in Ontario and one of the largest in North America for the needs of the Province of Ontario. Hydro One has a highly skilled and experienced workforce using first-class operating systems located in a state-of-the-art Control Centre. Hydro One is a team working together and safely to ensure Ontario has a safe, reliable supply of electricity.
Transmission Asset Management	Provide asset strategies, investment plans and work definition for the sustainment of the transmission grid to enable safe, reliable, efficient and cost effective delivery in a customer-focused commercial culture that increases enterprise value for our shareholder that provides increased value to our customers.
VP- Planning	Oversees Distribution Asset Management, Transmission Asset Management, Planning and Optimization, Network Connections and Development, System Planning, and Reliability, Strategies, and Compliance.
EVP Office- Operations	Oversight of Operations group.
Outsourcing Services	Manage overall business relationship between Hydro One and Inergi LP.
Strategic Services	Supports the executive team by advancing key strategic initiatives and interfacing with Lines of Business to assist in the implementation of these initiatives, coordinating the development of processes to ensure alignment within the Company and a focus on our key priorities, and providing support to the President and CEO and the Leadership Team.
Information Services	
Corporate Projects	Deliver the projects necessary to maintain and enhance the core services Hydro One provides to its customers across the province. Project delivery is completed by leveraging both internal and external expertise to design and construct using standard and repeatable methods that lead to safe, reliable and cost effective operations of those assets.
Information Technology	Information technology security; Enterprise IT architecture; Service

FUNCTIONS AND SERVICES	DESCRIPTION
	delivery; Technology services; Governance of IT architecture, Business analysis and information management, Project management; Inergi & Telecom services management. Applications; Compliance security; Data services; Information services; IT operations; System architecture.
Security Operations	Incident reporting and security awareness; Threat intelligence gathering; Physical security and asset threat and risk assessments; Investigations; Theft of electricity consultation and detection; Workplace violence prevention and response; Contract security procurement assistance; Overall security and asset protection advice; Security infrastructure Capital and OM&A investment planning and project management.
Customer & Corporate Relations	
Customer Care Services	Service the approximately 1.1 million distribution customers. Improve customer satisfaction through strategic system and process enhancements, effective services contracting, proactive communications and quality programs. Service programs include meter reading, billing, settlements, customer contact handling and collections. Project work includes regulatory compliance initiatives and service enhancements.
Customer Strategy and Conservation	Design and deliver energy conservation and demand management incentive based programs; Leverage Smart Grid investments to provide customer enablement of new technologies for energy management; Co-ordinate Greener Choices program; Provide input to Corporate Strategic Plan and develop recommendations on emerging strategic opportunities.
Customer Program Delivery	Supports Customer Service and Corporate Relations with five year business plans and the associated three year Dx Rate Filings with the OEB. Includes the Credit & Collections team is focused on reducing arrears and bad debt for both active and final-billed accounts, while working with customers on a variety of payment options to increase customer choice and provide more payment flexibility. Also included is the new Conservation and Demand Management team that delivers province-wide programs in order to meet multi-year targets aimed at reducing energy peaks and the overall consumption on the electricity grid.
Key Account Management	Manage relationships with Hydro One's large customers including over 90 Transmission-connected Industrials, 79 LDCs and 33 Transmission-connected Generators, representing almost 70% of Hydro One's revenues. Includes Operating Support; Account Executives; Contract Management; and Customer Programs.
VP Customer Service	Oversees Customer Service group, which has overall accountability for relationship, affordability and value proposition for products and services provided to customers. Includes bill management, major accounts and value-added services (e.g. conservation). Customer Service also responsible for Advanced Distribution System Project and Smart Meters.

FUNCTIONS AND SERVICES	DESCRIPTION
Meter To Bill	Focused on providing clear, accurate, and timely bills to customers. This includes validation of meter reading data, bill calculations, exception handling, retailer transactions, bill creation, bill insertion, and bill issuance.
Corporate Affairs	Support all external and internal communications initiatives. Interact with most other Hydro One departments; special focus on Customer Service. Support major projects including: development of partnership activities; coordinate with external energy agencies (e.g. OPA, IESO), Ministries in Ontario Public Service and internal Hydro One resources. Participate in pre-public consultations with municipalities and First Nations. Support customer strategy, rate strategy, distribution generation strategy; develop working relationships with customers, regulators, shareholder, lenders; labour relations; corporate culture. Includes SVP Customer & Corporate Relations - Oversees the entire Customer Service organization as well as the old Corporate Relations group, including Corporate Affairs, First Nations and Metis Relations and Key Account Management.
First Nations and Métis Relations	Provide First Nations and Métis consultation advice and support; Advise re First Nations and Métis HR strategies; Provide strategic advice to Remotes with respect to First Nations and Métis issues.
Bad Debt and Goodwill	Bad Debt related to Distribution service. Allocated 100% to Distribution.
SVP Customer and Corporate Relations	Oversees VP Customer Service, Key Account Management, Corporate Affairs and First Nations and Métis Relations.
Inergi LP (outsourced services)	
Finance and Accounting Services	Accounts Payable; Accounts Receivable (non-energy); Fixed asset and project cost accounting; general accounting and planning, budgeting and reporting
Human Resources- Pay services	Payroll and related services
Accounts Payable	Invoice processing and payment
People and Culture	
People and Culture	Primarily employee-related services, including administer compensation & benefits programs; decision support for business units; talent management (hiring, succession, development, coaching; high potential employee assessments); recruitment and diversity (diversity programs, grad program, student/co-op, line of business resourcing); data administration; consulting support to LOBs and corporate functions; VP Human Resources. Provide full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. Involves

FUNCTIONS AND SERVICES	DESCRIPTION
	interaction with 21 unions and 24 collective agreements.
Audit	
Audit	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives. This includes the VP Chief Risk Officer.
General Counsel & Secretariat	
General Counsel & Secretariat	Provides legal advice to all business units, acting as an internal "law firm" for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Telecom Services	
Telecom Services	Provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.
VP Chief Risk Officer	
VP Chief Risk Officer	The VP Chief Risk Office group creates an enterprise-wide comprehensive and uniform approach to anticipate, identify, prioritize, measure, treat and report on key business risks impacting our organization. It puts in place the policies, common processes, competencies, accountabilities, reporting and enabling technology to execute that approach successfully.

Exhibit B: Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), number of workstations, invoices to vendors
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets
Driver xBusiness Unit	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for Business Process Improvements is Operating Maintenance Capital, but Telecom and Remotes business units do not use the shared service, therefore activity cost driver is called Oper Maint Cap xTxR (i.e., Gross Utility Plant excluding Telecom and Remotes)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

COST OF SERVICE

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Service
Test (2017 and 2018) Years
Year Ending December 31
($ Millions)

Line No.	Particulars	2017 (a)	2018 (b)
1	Total Operation, Maintenance & Administrative Expenses	413.1	411.2
2	Depreciation & Amortization Expenses	435.7	470.7
3	Capital Taxes	0.0	0.0
4	Income Taxes	81.3	90.4
5	**Total Cost of Service**	**930.2**	**972.3**

1 **COMPARISON OF OM&A EXPENSE BY MAJOR CATEGORY– HISTORIC, BRIDGE AND TEST YEARS**

Transmission OM&A ($millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Sustaining OM&A							
Transmission Stations							
Land Assessment and Remediation	1.9	3.1	3.1	3.6	3.0	2.2	1.2
Environment Management	11.3	11.9	10.7	9.8	10.4	18.4	18.0
Power Equipment	55.7	60.2	61.4	64.5	54.3	60.0	57.0
Ancillary System Maintenance	10.1	10.1	10.0	9.2	10.8	11.2	11.2
Protection, Control, Monitoring, Metering and Telecommunications	44.9	49.4	52.1	63.9	61.2	60.9	62.0
Site Infrastructure Maintenance	22.7	25.2	24.5	24.0	25.1	25.7	25.3
Total Transmission Stations OM&A	**146.5**	**159.9**	**161.9**	**175.0**	**164.8**	**178.5**	**174.8**
Transmission Lines							
Rights of Way	27.1	31.1	35.5	32.6	35.8	33.8	34.8
Overhead Lines	17.9	15.7	17.6	15.9	18.0	20.9	20.8
Underground Cables	3.6	3.6	4.0	4.1	5.0	5.1	5.2
Total Transmission Lines OM&A	**48.6**	**50.4**	**57.1**	**52.6**	**58.8**	**59.8**	**60.8**
Engineering & Environmental Support	9.5	10.7	9.6	6.0	4.0	2.9	2.9
Total Sustaining OM&A	**204.7**	**221.0**	**228.6**	**233.6**	**227.5**	**241.2**	**238.5**
Development OM&A							
Technical Standards	2.5	3.1	3.3	2.8	3.0	2.5	2.6

Witness: Glenn Scott

Transmission OM&A ($millions)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Research Development and Demonstration	0.0	0.0	0.0	0.0	2.1	2.1	2.2
Customer Power Quality	0.0	0.0	0.0	0.0	0.2	0.2	0.2
Technology Studies	3.5	3.2	2.8	3.0	0.0	0.0	0.0
Smart Grid	2.4	2.2	1.4	0.3	0.0	0.0	0.0
Total Development OM&A	**8.4**	**8.6**	**7.5**	**6.1**	**5.3**	**4.8**	**5.0**
Operations OM&A							
Operations Contracts	21.4	21.3	20.9	22.4	22.9	23.6	24.3
Environmental, Health and Safety	1.3	1.5	1.1	1.1	1.6	1.9	1.8
Operators	32.1	33.9	34.6	35.5	35.5	35.9	36.1
Total Operations OM&A	**54.8**	**56.7**	**56.6**	**59.0**	**60.0**	**61.3**	**62.1**
Customer Service OM&A	**4.4**	**5.3**	**5.4**	**5.1**	**4.1**	**4.0**	**3.9**
OM&A Common Corporate Costs and Other Costs							
Asset Management	32.3	31.8	32.6	31.0	36.6	36.5	35.8
Common Corporate Functions & Services	80.5	87.7	93.1	95.7	98.9	98.3	97.6
Information Technology (including Cornerstone)	60.7	61.1	55.2	55.1	61.4	59.8	57.6
Cost of Sales	11.4	13.9	11.1	8.8	5.0	5.0	5.0
Other	-104.2	-118.6	-154.8	-116.8	-129.6	-149.7	-148.5
Total OM&A Common Corporate Costs and Other Costs	**80.7**	**75.8**	**37.2**	**73.9**	**72.3**	**49.9**	**47.5**
Property Taxes & Rights Payments	**62.1**	**21.2**	**64.1**	**63.9**	**62.9**	**63.6**	**64.3**
Pension Adjustment	-	-	-	-	-	-11.0	-8.0
B2M LP Adjustment	-	-	-	-	-	-0.8	-2.1
Total Transmission OM&A	**415.1**	**388.4**	**399.5**	**441.6**	**432.1**	**413.1**	**411.2**

REVENUE REQUIREMENT

1. SUMMARY OF REVENUE REQUIREMENT

Hydro One Transmission has followed standard regulatory practice in the calculation of revenue requirement as follows:

Table 1: Revenue Requirement ($ Millions)

Particulars	2017	2018	Reference
OM&A	413.1	411.2	C1, Tab 2, Schedule 1
Depreciation & Amortization	435.7	470.7	C2, Tab 3, Schedule 1
Income Taxes	81.3	90.4	C1, Tab 8, Schedule 1
Cost of Capital[1]	676.1	714.9	D1, Tab 4, Schedule 1
Total Revenue Requirement	**1,606.3**	**1,687.2**	E2, Tab 1, Schedule 1

[1] Includes Interest Capitalized recovery on the Niagara Reinforcement Project (2017 - $5 million and 2018 - $5 million).

The resultant revenue requirement of $1,606.3 million for 2017 and $1,687.2 million for 2018 are the amounts required by Hydro One Transmission to safely address customer service and system reliability needs at the lowest practical cost.

2. CALCULATION OF REVENUE REQUIREMENT

The details of the OM&A and Depreciation components of the revenue requirement are as follows:

2.1 OM&A Expense ($ Millions)

	2017	**2018**
Sustaining	241.2	238.5
Development	4.8	5.0
Operations	61.3	62.1
Customer Care	4.0	3.9
Common Corporate and Other Costs	49.9	47.5
Taxes Other Than Income Tax	63.6	64.3
Pension Adjustment	-11.0	-8.0
B2M LP Adjustment	-0.8	-2.1
Total OM&A	**413.1**	**411.2**

2.2 Depreciation Expense ($ Millions)

	2017	**2018**
Depreciation	424.0	460.6
Amortization	11.8	10.1
Total Expense	**435.7**	**470.7**

3. RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2016 TO YEAR 2017

Table 2 compares, by element, the 2016 rates revenue requirement (as per EB-2014-0140) against the 2017 proposed rates revenue requirement.

Table 2: Comparison of Rates Revenue Requirements:
Board Approved 2016 vs. 2017 ($Millions)

Line no.	Description	Year 2016	Year 2017	Difference
1	OM&A	436.7	413.1	(23.6)
2	Depreciation	397.3	435.7	38.5
3	Income Taxes	72.2	81.3	9.1
4	Cost of Capital [1]	661.5	676.1	14.6
5	Total Revenue Requirement	1,567.7	1,606.3	38.6
	Deduct External Revenues [2]	**(32.2)**	**(28.2)**	**4.0**
6	Revenue Requirement less External Revenues	1,535.4	1,578.1	42.7
	Deduct Export Revenue Credit [3]	**(31.7)**	**(39.2)**	**(7.5)**
7	Deduct Regulatory Accounts Disposition [4]	(36.1)	(47.8)	(11.7)
8	Add Low Voltage Switch Gear [5]	13.0	14.0	1.0
9	Rates Revenue Requirement	**1,480.7**	**1,505.1**	**24.4**

1 Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
2 External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
3 Export revenue is addressed in Exhibit H1, Tab 4, Schedule 1.
4 See Exhibit F1, Tab 1, Schedule 3 for further details.
5 Low Voltage Switch Gear is addressed in Exhibit G1, Tab 3, Schedule 1.

There are a number of key operational and financial factors contributing to the increased rates revenue requirement that have an impact across the cost components in Table 2. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation and the return on capital. Also contributing to the difference is higher income taxes, and lower external revenues. These increases were partially offset by a lower cost of debt, lower OM&A, increased regulatory account disposition, and a higher export revenue credit.

Table 3 illustrates the value of the key impacts on the increase in the rates revenue requirement.

Table 3: Components of Change to Rates Revenue Requirement 2016[1] vs. 2017

Description	Amount ($M)
Decrease in OM&A	(23.6)
Rate Base Growth	70.7
Decrease in Cost of Debt	(17.7)
No Change in Cost of Equity	-
Tax - timing differences and other	9.1
External Revenue	4.0
Increase in Export Revenue Credit	(7.5)
Increase in Regulatory Accounts Disposition	(11.6)
Increase in Low Voltage Switch Gear	1.0
Total Change	**24.4**

4. RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2017 TO YEAR 2018

Table 4 compares, by element, the 2017 rates revenue requirement against the 2018 rates revenue requirement.

[1] 2014 Amounts as per Hydro One Transmission's 2014 Revenue Requirement and Charge Determinants for EB-2012-0031 and EB-2011-0268.

Table 4: Comparison of Rates Revenue Requirements 2017 vs. 2018 ($ Millions)

Line no.	Description	Year 2017	Year 2018	Difference
1	OM&A	413.1	411.2	(1.9)
2	Depreciation	435.7	470.7	35.0
3	Income Taxes	81.3	90.4	9.1
4	Cost of Capital[1]	676.1	714.9	38.8
	Total Revenue Requirement	**1,606.3**	**1,687.2**	**80.9**
5	Deduct External Revenues[2]	(28.2)	(28.5)	(0.3)
	Revenue Requirement less External Revenues	**1,578.1**	**1,658.7**	**80.6**
6	Deduct Export Revenue Credit[3]	(39.2)	(40.1)	(0.9)
7	Deduct Regulatory Accounts Disposition[4]	(47.8)	(47.8)	-
8	Add Low Voltage Switch Gear[5]	14.0	14.7	0.7
	Rates Revenue Requirement	**1,505.1**	**1,585.6**	**80.5**

[1] Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
[2] External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
[3] Export revenue is addressed in Exhibit H1, Tab 4, Schedule 1.
[4] See Exhibit F1, Tab 1, Schedule 3 for further details.
[5] Low Voltage Switch Gear is addressed in Exhibit G1, Tab 3, Schedule 1.

The increase in 2018 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in depreciation and the return on capital. Also contributing the increased rate base is due to higher income taxes. These increases are partially offset by a lower cost of debt, lower OM&A, and a higher export revenue credit.

Table 5 illustrates the value of the key impacts on the movement in the rates revenue requirement.

Table 5: Components of Change to Rates Revenue Requirement 2017 vs. 2018

Description	Amount ($M)
Decrease in OM&A	(1.9)
Rate Base Growth	77.5
Decrease in Cost of Debt	(3.7)
No Change in Cost of Equity	-
Tax - timing differences and other	9.1
External Revenue	(0.3)
Increase in Export Revenue Credit	(0.9)
No Change in Regulatory Accounts Disposition	-
Increase in Low Voltage Switch Gear	0.7
Other	-
Total change	**80.5**

[1] Net of External Revenue

Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.

EXTERNAL REVENUES

1. INTRODUCTION

This Exhibit describes Hydro One's work and associated external revenues that are used to calculate rates revenue requirement as detailed in Exhibit E, Tab 1, Schedule 1.

Hydro One's strategy is to focus on core work, while continuing to be responsive to external customer work requests where Hydro One has available resources and/or assets to accommodate the request.

External revenues earned through the provision of services to third parties are forecast to be $28.2 million in 2017 and $28.5 million in 2018 and account for approximately 1.8% and 1.7% of Hydro One Transmission revenues for 2017 and 2018 respectively. These external revenues are used to offset the revenue requirement from Hydro One Transmission tariffs and thereby reduce the required revenue to be collected from transmission ratepayers.

2. COSTING AND PRICING

The costing of external work is determined on the basis of cost causality, with estimates calculated in the same way as internal work estimates, using the standard labour rates, equipment rates, material surcharge, and overhead rates. (See Exhibit C1, Tab 5, Schedule 1 for a description of costing of work.) An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit for the transmission ratepayers. The costs associated with external work are described in more detail in Exhibit C1, Tab 3, Schedule 6.

3. DESCRIPTION

Table 1 details Hydro One Transmission's external revenues for the period 2012 to 2018.

Table 1: External Revenues ($ Millions)

$M	2012 Historic	2013 Historic	2014 Historic	2015 Historic	2016 Bridge	2017 Test	2018 Test
Secondary Land Use	22.0	21.1	19.1	31.6	15.2	15.4	15.6
Station Maintenance	13.9	12.6	14.7	9.5	5.2	5.3	5.3
Engineering & Construction	2.3	2.2	0.1	0.4	0.0	0.0	0.0
Other External Revenues	3.8	10.7	10.5	12.8	7.4	7.5	7.6
Totals	**42.0**	**46.6**	**44.4**	**54.3**	**27.9**	**28.2**	**28.5**

3.1 Secondary Land Use

Hydro One manages the Provincial Secondary Land Use Program ("PSLUP") on behalf of the Province, to whom Hydro One's transmission corridor lands were transferred under Bill 58 on December 31, 2002. The program focuses on licensing and leasing the transmission corridor lands to external parties for "secondary" land use purposes that are compatible with Hydro One Transmission's primary business operations. Typical uses include parking lots, municipal roadways, parks and trails, agricultural areas, water mains and other municipal infrastructure occupations, as well as public transit parking lots and station operations. The PSLUP revenue stream is generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement renewals, as well as lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway).

Under Bill 58 provisions (*An Act to amend certain statutes in relation to the energy sector*, c.1, S.O. 2002) and subsequently negotiated arrangements, all expiring corridor PSLUP agreements were transferred to the Province as of December 31, 2002. Remaining unexpired corridor agreements and associated revenue streams are retained by Hydro One until such time as these agreements expire. Upon expiration, the previously retained agreements and revenue streams by Hydro One are then also transferred to the Province under the PSLUP.

Notwithstanding this transfer, Hydro One has provided front-line delivery services for the PSLUP on behalf of the Province since 2002. As of April 1, 2015, Hydro One was granted the right under agreement to continue delivery of the program through March 31, 2020. The arrangements set out in the agreement include Hydro One's retention of PSLUP revenues for unexpired agreements until their expiry, as well as a results-based compensation model involving the sharing of revenues between Hydro One and the Province for new PSLUP agreements and for renewals of expired agreements which were previously transferred to the Province. Hydro One also manages a small portion of secondary land use revenue that does not fall under current PSLUP arrangements.

As a result, responsibility for the management and re-negotiation (as required) of all existing secondary land use agreements (including those previously transferred to the Province under the corridor land transfer arrangements) now rests with Hydro One. Hydro One will continue promoting and negotiating all new secondary land use business opportunities, where these are consistent with Hydro One Transmission's short and longer-term operational requirements.

The secondary land use revenue levels were $31.6 million in 2015. They are forecasted to drop to $15.2 million in 2016 and stabilize during the test years. Historical figures in years 2013 to 2015 are higher due to unbudgeted one-time transactions involving easement grants (e.g. water mains) and operational land sales (e.g. roadways).

3.2 Station Maintenance

Revenues from external work in the station services segment include specialized activities similar to those performed internally for Hydro One Transmission. These activities include repairing electrical equipment (such as transformers, breakers and switches), specialty machining (spindles), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services. Customers seek out station services skills resident within Hydro One, requiring highly specialized staff able to perform work on a variety of high voltage equipment in a variety of work settings (such as nuclear environments). Work is performed according to commercially negotiated contracts which reflect market level pricing.

Hydro One provides support to the external market place in areas which are related to Hydro One Transmission. This work is primarily tied to support Ontario’s key generation suppliers: Bruce Power LLP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. in support of Ontario Power Generation Inc.

As can be seen in Table 1, this segment of external revenue is expected to decrease in 2016 through to 2018, primarily due to a lower volume of work from major customers.

3.3 Engineering and Construction

Hydro One's engineering and construction activities focus on internal work supporting the growing Hydro One Transmission work program, while striving to reduce external work to a minimal level. This segment of external revenue was derived from upgrading revenue meters at various sites pursuant to IESO requirements. This work was completed in 2015.

3.4 Other External Revenues

"Other" external revenues set out in Table 1 include revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fiber), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include a transfer price charge to Hydro One Telecom Inc. and Hydro One Remote Communities Inc. as described in Exhibit B1, Tab 3, Schedule 9. In 2017 and 2018, forecasted revenues include $4.0 million each year for the lease of idle transmission lines.

CALCULATION OF REVENUE REQUIREMENT

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Revenue Requirement
Year Ending December 31
($ Millions)

Line No.	Particulars	2017 (a)	2018 (b)
	Cost of Service		
1	Operating, maintenance & administrative	$ 413.1	$ 411.2
2	Depreciation & amortization	435.7	470.7
3	Capital taxes	0.0	0.0
4	Income taxes	81.3	90.4
5	Cost of service excluding return	$ 930.1	$ 972.3
6	Return on capital	671.5	710.3
7	AFUDC recovery on Niagara Reinforcement Project	4.6	4.6
8	Total revenue requirement	$ 1606.3	$ 1687.2

Witness: Glenn Scott

COST ALLOCATION AND RATE POOL REVENUE REQUIREMENT

1. INTRODUCTION

The purpose of Exhibit G1 is to describe the process followed by Hydro One to allocate the transmission rates revenue requirement into rate pools.

This schedule sets the context for cost allocation in this Application and provides Hydro One's transmission rates revenue requirement input that is used to determine the Uniform Transmission Rates ("UTR").

The remaining schedules of Exhibit G1 provide further explanation on:

- the cost allocation methodology to functional categories (refer to Exhibit G1, Tab 2, Schedule 1), and
- the aggregation of functional categories into the Network, Line Connection and Transformation Connection rate pools (refer to Exhibit G1, Tab 3, Schedule 1).

2. SUMMARY

In Hydro One's 2015/2016 Transmission Rate Application (EB-2014-0140), the Board approved Hydro One's methodology to allocate the transmission rates revenue requirement into four rate pools: Network, Line Connection, Transformation Connection and Wholesale Meter. Given that Wholesale Meters now account for less than 0.1% of the revenue requirement, this Application proposes to simplify the allocation process by eliminating the Wholesale Meter rate pool and allocating the rates revenue requirement into the three remaining rate pools: Network, Line Connection and Transformation

Connection. The basis and details of this proposal are outlined further in Exhibit G1, Tab 2, Schedule 1, and Exhibit H1, Tab 3, Schedule 1.

Other than the change related to Wholesale Meters, the cost allocation methodology has not changed from what was approved by the Board in the Decision and Rate Order in Proceeding EB-2014-0140.

Table 1 below summarizes the allocation of Hydro One's transmission rates revenue requirement into the proposed rate pools. This summary of rate pool revenue requirement represents Hydro One Transmission's input into the determination of the provincial 2017 and 2018 UTRs. The UTRs are collected by the Independent Electricity System Operator ("IESO") from market participants who are defined transmission customers in Ontario.

Table 1: Summary of Rates Revenue Requirement by Rate Pool ($Millions)

Year	Network	Line Connection	Transformation Connection	Total*
2017	853.4	214.3	437.1	1504.7
2018	898.9	226.4	460.0	1585.3

*This amount is net of the $0.3million in WMS revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.

NETWORK, LINE CONNECTION AND TRANSFORMATION CONNECTION RATE POOLS

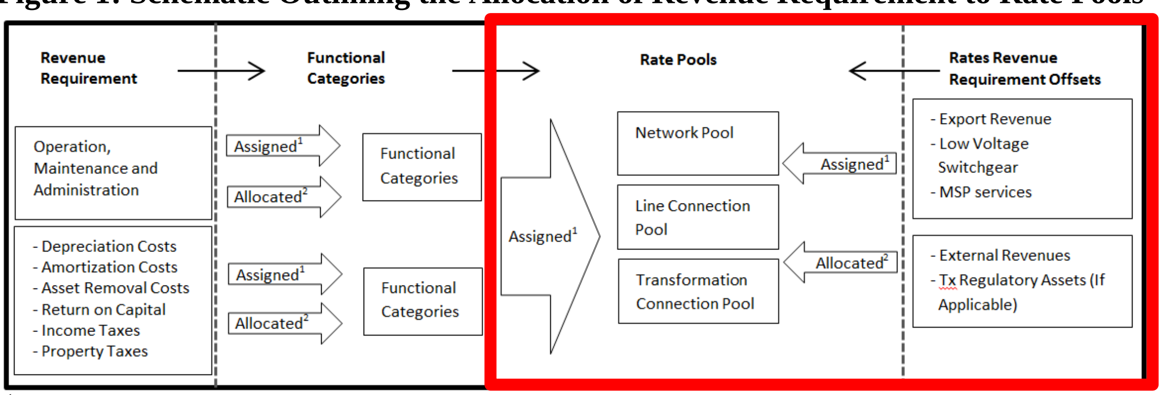
1. INTRODUCTION

This exhibit describes the activities to determine the transmission rates revenue requirement for the Network, Line Connection, and Transformation Connection rate pools, and provides a summary of the associated asset value and rates revenue requirement. A detailed account of the 2017 and 2018 transmission rates revenue requirement by rate pool is provided in Exhibit G2, Tab 5, Schedule 1.

2. ALLOCATION OF REVENUE REQUIREMENT TO RATE POOLS

The allocation of the transmission rates revenue requirement to the rate pools is summarized in Figure 1. This process is the same as was presented in Hydro One's 2015/2016 Transmission Rate Application approved by the Board in Proceeding EB-2014-0140.

Figure 1: Schematic Outlining the Allocation of Revenue Requirement to Rate Pools



[1] *The term "Assigned" refers to a value that is designated to a particular Functional Category or Rate Pool (e.g. Export Revenues are directly assigned to the Network Rate Pool)*

[2] *The term "Allocated" indicates that a parameter(s) is used to calculate the proportion of the values that are designated to more than one Functional Category or Rate Pool (e.g. load forecast data is applied to the value of Dual Function Line assets to determine the proportion of its value that is allocated to the Network Functional Category and to the Line Connection Functional Category)*

As illustrated in Figure 1, once the allocation of revenue requirement components into the functional categories is completed, as described in Exhibit G1, Tab 2, Schedule 1, then the next steps include:

1. Mapping of allocated transmission costs from the functional categories to the assigned rate pools; and
2. Assignment and allocation of the rates revenue requirement offset components such as: Export Transmission Service ("ETS") revenue credit and associated variance accounts, regulatory assets (if applicable), the Low Voltage Switchgear ("LVSG") credit, Wholesale Meter Service ("WMS") revenue and other external revenues into the rate pools.

These two steps are discussed further in Section 2.1 and Section 2.2 respectively.

2.1 Mapping of Functional Category to Rate Pool

The allocated transmission costs that are derived using the cost allocation methodology described in Exhibit G1, Tab 2, Schedule 1, are aggregated from the functional categories to the three rate pools: Network, Line Connection, and Transformation Connection; as shown in Table 1 and described below.

Table 1: Functional Category to Rate Pool Mapping

Functional Category	Rate Pool
Network	Network
Network Portion of DFL	Network
Line Connection	Line Connection
Line Connection Portion of DFL	Line Connection
Transformation Connection	Transformation Connection
Generation Line Connection	Network
Generation Transformation Connection	Network
Common and Other	Prorate to Network, Line and Transformation

Network, Line Connection, and Transformation Connection Assets

The financial values associated with the Network, Line Connection, and Transformation Connection functional categories are directly assigned to the Network, Line Connection, and Transformation Connection rate pools respectively. This is also applicable to the portions of Dual Function Line ("DFL") assets that are allocated to the Network and Line Connection functional categories.

Generation Line and Transformation Connection Assets

The financial values associated with the Generator Line and Transformation Connection functional categories are assigned to the Network rate pool, based on the Board Decision under Proceeding RP-1999-0044; which states that generators do not pay transmission service charges with respect to transmission connection facilities used to transfer electricity from the generating station to the network. This approach is considered fair and equitable, since generators connected to the transmission system enhance and contribute to the electricity market for all load customers. This aligns with the cost allocation to the Network rate pool where costs are recovered through Network rates applicable to all load customers, while the costs for Connection rate pools are recovered only from load customers that utilize those connections.

Common and Other Assets

The financial values associated with the functional categories "Common" and "Other" are allocated to the Network, Line Connection and Transformation Connection rate pools in proportion to the corresponding amounts of financial values that are already assigned to those rate pools by revenue requirement component (i.e. "Common" and "Other" OM&A costs are allocated to the rate pools based on the relative share of OM&A costs already assigned to the rate pools).

2.2 Allocation of Rates Revenue Requirement Offsets

Hydro One Transmission's revenue requirement to be recovered through rates includes amounts in addition to the fixed asset depreciation costs, return on capital, income taxes, and OM&A costs, allocated above. These costs are discussed in Exhibit E1, Tab 1, Schedule 1 and are generically defined for the purpose of this exhibit as "Rates Revenue Requirement Offsets".

Table 2 below identifies the Rates Revenue Requirement Offset items, the total revenues to be collected and the allocators used to divide these costs among the three rate pools. Allocation of the items in Table 2 is done on the same basis as under Proceeding EB-2014-0140.

Table 2: Rates Revenue Requirement Offsets
($Millions)

Items	Rates Revenue Requirement		Allocator
	2017	2018	
Regulatory Assets	(38.6)	(38.6)	Prorated based on the amounts of financial values that are already assigned to those functional categories
Export Transmission Service Revenue Variance	(9.2)	(9.2)	Direct Assignment to Networks
Export Transmission Service Revenue	(39.2)	(40.1)	Direct Assignment to Networks
External Revenues	(28.2)	(28.5)	Prorated based on the amounts of financial values that are already assigned to those functional categories
Wholesale Meter Service Revenue	(0.3)	(0.3)	Direct Assignment to Transformation Connection
Funding for Low Voltage Switchgear Compensation	14.0	14.7	Direct Assignment to Transformation Connection

3. SUMMARY OF ASSET VALUE AND REVENUE REQUIREMENT FOR RATE POOLS

This section provides the annual mid-year net book value and rates revenue requirement for each of the three rate pools: Network, Line Connection, and Transformation Connection, derived using the methodology described above in Section 2.

3.1 Network Rate Pool

Transmission facilities that are used for the benefit of all customers, or have been approved by the Board as being for the benefit of all customers in the province, are included in the Network rate pool. The mid-year net book value and rates revenue requirement for the Network rate pool are provided in Table 3.

The rates revenue requirement for the Network rate pool includes an offset of $39.2 million and $40.1 million in export transmission service revenue forecast to be collected in 2017 and 2018, respectively, as discussed in Exhibit H1, Tab 4, Schedule 1, as well as an offset of $9.2 million in export transmission service variance in each year, as discussed in Exhibit F1, Tab 1, Schedule 1.

Table 3: Network Rate Pool

($Millions)

Year	Net Book Value	Rates Revenue Requirement
2017	6,229.8	853.4
2018	6,612.6	898.9

3.2 Line Connection Rate Pool

Transmission facilities that are used to provide a connection to a load supply point(s) for one or more customers are included in the Line Connection rate pool. The mid-year net book value and rates revenue requirement for the Line Connection rate pool are provided in Table 4.

Table 4: Line Connection Rate Pool

($Millions)

Year	Net Book Value	Rates Revenue Requirement
2017	1,554.2	214.3
2018	1,649.2	226.4

3.3 Transformation Connection Rate Pool

Transmission facilities that are used to step-down voltage from the transmission level to the distribution level (i.e. from above 50 kV to below 50 kV) are included in the Transformation Connection rate pool. The mid-year net book value and rates revenue requirement for the Transformation Connection rate pool are provided in Table 5.

The rates revenue requirement for the Transformation Connection rate pool includes: the LVSG compensation amount of $14.0 million and $14.7 million to be collected in 2017 and 2018, respectively (as outlined below), as well as an offset of $0.3 million in WMS revenue forecast to be collected in each year, as discussed in Exhibit H1, Tab 3, Schedule 1.

Table 5: Transformation Connection Rate Pool

($Millions)

Year	Net Book Value	Rates Revenue Requirement
2017	2,743.7	437.1
2018	2,936.0	460.0

Low Voltage Switchgear Compensation

As first approved by the Board in Proceeding EB-2006-0051, the revenue requirement for the Transformation Connection pool also includes an amount that is payable by Hydro One Transmission to Toronto Hydro-Electric System Inc. and Hydro Ottawa Inc. as compensation for LVSG equipment that those utilities own, operate and maintain within the transformation stations owned by Hydro One. The compensation amount is based on the LVSG as a proportion of the total transformation station costs, including OM&A and capital-related charges, incurred by Hydro One.

The estimate of the cost of providing low voltage switchgear service, and the methodology used to calculate the annual LVSG compensation payable to each utility, was most recently approved in Proceeding EB-2014-0140. The average low voltage switchgear service costs continue to comprise 19.0% of Hydro One Transmission's total station costs.

The LVSG compensation is based on the forecast of each eligible utility's total monthly non-coincident peak demand supplied from all Hydro One Transmission transformer stations in which the utilities own the LVSG facilities, multiplied by the LVSG proportion of Hydro One Transmission's Transformation Connection rate.

The annual LVSG compensation amount will be $14.0 million in 2017 and $14.7 million in 2018 as shown in Table 6. These amounts are added to the revenue to be collected by the Transformation Connection service charges.

Table 6: LVSG Compensation

Year	LVSG Component of Transformation Connection Rate ($/kW/Month)	Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)	Total Credit ($ Millions)
2017	0.40	35,132.49	14.0
2018	0.42	35,177.78	14.7

OM&A COSTS BY FUNCTIONAL CATEGORY

(Excludes Property Tax and Rights)

Functional Category	OM&A ($ Millions)	
	2017	**2018**
Network	98.7	97.8
Line Connection	20.9	21.0
Transformation Connection	60.0	58.9
Network - Dual Function Line	15.3	15.6
Line Connection - Dual Function Line	3.2	3.3
Generation Line Connection	3.6	3.5
Generation Transformation Connection	1.9	1.9
Common	137.9	136.8
Other Assets	8.0	8.1
TOTAL	**349.5**	**346.9**

DETAILED REVENUE REQUIREMENT BY RATE POOL

2017 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($ Millions)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
OM&A	205.1	41.5	102.9	349.5
Taxes other than Income Taxes	37.6	9.4	16.6	63.6
Depreciation of Fixed Assets	218.6	53.0	111.0	382.6
Capitalized Depreciation	(7.1)	(1.8)	(3.2)	(12.1)
Asset Removal Costs	31.4	8.0	14.0	53.4
Other Amortization	7.0	1.7	3.1	11.8
Return on Debt	170.5	42.5	75.1	288.2
Return on Equity	229.6	57.3	101.1	388.0
Income Taxes	48.1	12.0	21.2	81.3
SUB-TOTAL	**940.9**	**223.6**	**441.9**	**1,606.3**
Less External Revenues	(16.5)	(3.9)	(7.8)	(28.2)
Less WMS Revenue	0.0	0.0	(0.3)	(0.3)
Less Regulatory Asset Credit	(22.6)	(5.4)	(10.6)	(38.6)
Less Export Revenue Variance	(9.2)	0.0	0.0	(9.2)
Less Export Revenues	(39.2)	0.0	0.0	(39.2)
Plus LVSG Credit	0.0	0.0	14.0	14.0
TOTAL*	**853.4**	**214.3**	**437.1**	**1,504.7**

**This amount is net of the $0.3million in WMS revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.*

1 **2018 Detailed Revenue Requirement by Rate Pool**

	Rate Pool Revenue Requirement ($ Millions)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
OM&A	204.1	41.7	101.1	346.9
Taxes other than Income Taxes	38.0	9.5	16.9	64.3
Depreciation of Fixed Assets	230.7	56.1	117.3	404.1
Capitalized Depreciation	(7.5)	(1.9)	(3.4)	(12.8)
Asset Removal Costs	40.6	10.3	18.3	69.2
Other Amortization	6.0	1.5	2.7	10.1
Return on Debt	178.5	44.5	79.3	302.2
Return on Equity	243.7	60.8	108.2	412.6
Income Taxes	53.4	13.3	23.7	90.4
SUB-TOTAL	**987.4**	**235.8**	**464.0**	**1,687.2**
Less External Revenues	(16.7)	(4.0)	(7.8)	(28.5)
Less WMS Revenue	0.0	0.0	(0.3)	(0.3)
Less Regulatory Asset Credit	(22.6)	(5.4)	(10.6)	(38.6)
Less Export Revenue Variance	(9.2)	0.0	0.0	(9.2)
Less Export Revenues	(40.1)	0.0	0.0	(40.1)
Plus LVSG Credit	0.0	0.0	14.7	14.7
TOTAL*	**898.9**	**226.4**	**460.0**	**1,585.3**

** This amount is net of the $0.3million in WMS revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.*

2

BILL IMPACTS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. For the purpose of determining the impact of proposed changes to transmission rates on an average customer's bill the same approach used in the EB-2014-0140, EB-2012-0031 and EB-2010-0002 transmission rate applications has been adopted.

Table 1 below shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

Table 1: Transmission Cost as a Percentage of Total Bill

Bill Component	¢/kWh	Source
Commodity	10.14	IESO Monthly Market Report December 2015
Wholesale Market Service Charges	0.39	IESO Monthly Market Report December 2015
Wholesale Transmission Charges	1.02	IESO Monthly Market Report December 2015
Debt Retirement Charge	0.70	IESO Monthly Market Report December 2015
Distribution Service Charges	2.85	2014 Yearbook of Electricity Distributors
Total Cost	**15.10**	
Transmission as Percentage of Total Cost for Dx-connected customers		***6.8%***
Transmission as Percentage of Total Cost for Tx-connected customers		***8.3%***

The figures from Table 1 have been applied to the proposed increase in transmission revenue requirement in 2017 and 2018 to establish average bill impacts as shown in Table 2.

Table 2: Average Bill Impacts on Transmission and Distribution-connected Customers

	2016	2017	2018
Rates Revenue Requirement ($ millions) [1]	**1,480.5**	**1,504.7**	**1,585.3**
% Increase in Rates RR over prior year		1.6%	5.4%
% Impact of load forecast change		2.1%	0.0%
Net Impact on Average Transmission Rates		**3.7%**	**5.4%**
Transmission as a % of Tx-connected customer's Total Bill		8.3%	8.3%
Estimated Average Bill impact		***0.3%***	***0.4%***
Transmission as a % of Dx -connected customer's Total Bill		6.8%	6.8%
Estimated Average Bill Impact		***0.3%***	***0.4%***

[1] This amount is net of the $0.3million in WMS revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 350 kWh, 750 kWh and 1800 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 3.

Table 3: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	350 kWh	**750 kWh**	**1800 kWh**
Total Bill as of Jan 1, 2016[1]	$ 102.95	$ 179.37	$ 379.98
RTSR included in 2016 R1 Customer's Bill	$ 4.37	$ 9.36	$ 22.47
Estimated 2017 Monthly RTSR[2]	$ 4.52	$ 9.69	$ 23.26
2017 increase in Monthly Bill	**$ 0.15**	**$ 0.33**	**$ 0.79**
2017 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2018 Monthly RTSR[2]	$ 4.75	$ 10.18	$ 24.44
2018 increase in Monthly Bill	**$ 0.23**	**$ 0.49**	**$ 1.18**
2018 increase as a % of total bill	*0.2%*	*0.3%*	*0.3%*

[1] Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
[2] The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

The total bill impact for a typical Hydro One General Service Energy less than 50 kW ("GSe < 50 kW") customer consuming 1000 kWh, 2000 kWh and 15,000 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 4.

Table 4: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of Jan 1, 2016[1]	$ 262.79	$ 492.00	$ 3,471.80
RTSR included in 2016 GSe Customer's Bill	$ 10.19	$ 20.39	$ 152.89
Estimated 2017 Monthly RTSR[2]	$ 10.55	$ 21.11	$ 158.29
2017 increase in Monthly Bill	**$ 0.36**	**$ 0.72**	**$ 5.40**
2017 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*
Estimated 2018 Monthly RTSR[2]	$ 11.09	$ 22.18	$ 166.32
2018 increase in Monthly Bill	**$ 0.53**	**$ 1.07**	**$ 8.02**
2018 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*

[1] Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
[2] The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

2017 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-201X-XXXX

The rate schedules contained herein shall be effective January 1, 2017

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher 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. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**3.68**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.92**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.22**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. 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 an embedded generator unit 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, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. 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.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

2018 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-201Y-YYYY

The rate schedules contained herein shall be effective January 1, 2018

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher 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. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**3.86**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.97**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.33**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. 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 an embedded generator unit 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, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. 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.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

2017 Draft Uniform Transmission Rates and Revenue Disbursement Allocators

(Effective for period January 1, 2017 to December 31, 2017)

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,588,261	$900,913	$1,837,915	$6,327,089
CNPI	$2,528,224	$634,767	$1,294,962	$4,457,953
GLPT	$23,006,025	$5,776,176	$11,783,735	$40,565,936
H1N	$853,356,393	$214,254,171	$437,090,979	$1,504,701,543
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$915,444,049	$221,566,027	$452,007,591	$1,589,017,667

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,865.656	236,890.824	202,461.050	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,073.906	240,388.166	203,721.750	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.68**	**0.92**	**2.22**	
FNEI Allocation Factor	**0.00392**	**0.00407**	**0.00407**	
CNPI Allocation Factor	**0.00276**	**0.00286**	**0.00286**	
GLPT Allocation Factor	**0.02513**	**0.02607**	**0.02607**	
H1N Allocation Factor	**0.93218**	**0.96700**	**0.96700**	
B2MLP Allocation Factor	**0.03601**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.

Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.

Note 4: H1N Rates Revenue Requirement and Charge Determinants as proposed in application EB-2016-0160.

Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.

Note 6: Calculated data in shaded cells.

2018 Draft Uniform Transmission Rates and Revenue Disbursement Allocators

(Effective for period January 1, 2018 to December 31, 2018)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,587,559	$903,548	$1,835,982	$6,327,089
CNPI	$2,527,729	$636,624	$1,293,600	$4,457,953
GLPT	$23,001,523	$5,793,073	$11,771,340	$40,565,936
H1N	$898,899,737	$226,393,327	$460,024,073	$1,585,317,138
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$960,981,695	$233,726,572	$474,924,995	$1,669,633,262

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,132.407	240,445.584	203,770.823	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.86**	**0.97**	**2.33**	
FNEI Allocation Factor	**0.00373**	**0.00387**	**0.00387**	
CNPI Allocation Factor	**0.00263**	**0.00272**	**0.00272**	
GLPT Allocation Factor	**0.02394**	**0.02479**	**0.02479**	
H1N Allocation Factor	**0.93540**	**0.96862**	**0.96862**	
B2MLP Allocation Factor	**0.03430**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.
Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.
Note 4: H1N Rates Revenue Requirement and Charge Determinants as proposed in application EB-2016-0160.
Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.
Note 6: Calculated data in shaded cells.