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Frank D'Andrea
Vice President, Regulatory Affairs & Chief Risk Officer

BY COURIER

March 21, 2019

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-2019-0082 – Hydro One Networks Inc.'s 2020-2022 Transmission Custom IR Application and Evidence Filing

Hydro One Networks Inc.'s (Hydro One) three-year Transmission Custom IR Application for the period 2020-2022 and prefiled evidence in support of the Application has been submitted using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System. The Application includes Hydro One's transmission system plan and rate information needed to support the issuance of notice by the Ontario Energy Board.

Hydro One's 2018 audited financial statements for its transmission business will be finalized at the end of April 2019. At that time, Hydro One will update the Application to replace 2018 forecast numbers with actuals. These will be reflected in a Blue Page update that will be filed in mid-2019.

Hydro One intends to post electronic copies of the Application and supporting evidence on its website for public access. A text-searchable Adobe Acrobat electronic version and two paper copies of the Application will be sent to the OEB shortly.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

EXHIBIT LIST

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APPLICATION

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.

1. The applicant, Hydro One Networks Inc. (“Hydro One”), a subsidiary of Hydro One Limited, is an Ontario corporation with its head office in Toronto. Hydro One 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. This is an application for a Custom Incentive Rate-Setting (“IR”) framework to cover a three-year test period commencing January 1, 2020 and ending December 31, 2022. The revenue requirement for the 2020 test year has been determined using a cost of service approach. The revenue requirements for subsequent years will be formulaically determined using a proposed Custom IR model.

3. Hydro One hereby applies to the Ontario Energy Board (the “Board” or the “OEB”) for orders approving:

    a) A total revenue requirement of $1,673.4 million for the 2020 test year, to be effective and implemented on January 1, 2020, along with an amendment to the Uniform Transmission Rates to allow for recovery of the proposed rates revenue requirement of $1,623.3 million for 2020.

b) The proposed Custom Incentive Rate-Setting model as a framework to set Hydro One's transmission revenue requirement for the period effective January 1, 2021 through December 31, 2022, as described in Exhibit A, Tab 4, Schedule 1.

c) The charge determinants by rate pool over the test period as outlined in Exhibit I2, Tab 2, Schedule 1.

d) The proposed Export Transmission Service ("ETS") rate. The proposed rate is $1.85/MWh for each of the test years, which was approved by the OEB in Hydro One's transmission revenue requirement application EB-2014-0410.

e) The fees associated with Wholesale Meter Service, as outlined in Exhibit I2, Tab 3, Schedule 1.

f) The continuation of Hydro One's current regulatory accounts.

g) Accounting Orders establishing an Earnings Sharing Mechanism Deferral Account and a CCRA True-Up Deferral account. Further details can be found in Exhibit H, Tab 1, Schedule 2 of the Application.

h) The disposition of regulatory assets outlined in Exhibit H, Tab 1, Schedule 1 with a total audited debit balance of $14.5 million reflecting the principal balances as at December 31, 2018, plus forecast interest less any amounts approved for disposition in 2019 by the OEB. Hydro One seeks approval to refund this amount as an offset to its revenue requirement of $4.8 million per year over a three-year period commencing January 1, 2020.

i) Other items or amounts that may be requested by Hydro One in the course of this proceeding, and as may be granted by the OEB.

4. This application has been prepared in accordance with the OEB's *Filing Requirements for Electricity Transmission Rate Applications* dated February 11, 2016.

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

6. The written evidence filed with the OEB may be amended from time to time prior to the OEB's final decision on the application.

NOTICE AND FORM OF HEARING REQUESTED

7. Given Hydro One's vast service territory, notice of this application should be published in newspapers with wide circulation in Ontario, including *The Toronto Star* and *The Globe and Mail* and *The Financial Post*.

8. The application may be viewed on the Internet at the following address: https://www.hydroone.com/abouthydroone/RegulatoryInformation/txrates

9. Hydro One requests that this application be heard by way of an oral hearing consistent with the proceedings for Hydro One's prior multi-year rate applications.

PROPOSED EFFECTIVE DATE

10. Hydro One requests that the OEB's rate orders be effective January 1, 2020. In order to address the possibility that the requested rate orders cannot be made effective by that time, Hydro One requests an interim Order making its current transmission revenue requirement and charges effective on an interim basis as of January 1, 2020 and establishing an account to recover any differences between the interim rates and the final rates effective January 1, 2020 based on the OEB's Decision and Order herein.

11. 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.

CONTACT INFORMATION

12. 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. Linda Gibbons
Senior Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service: 7th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

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Telephone: (416) 345-4373
Fax: (416) 345-5395
Electronic access: Regulatory@HydroOne.com

b) The Applicant's counsel:

Torys LLP

Address:	79 Wellington St. W, 30th Floor Box 270, TD South Tower Toronto ON M5K 1N2
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Charles Keizer

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DATED at Toronto, Ontario, this 28th day of February, 2019.

HYDRO ONE NETWORKS INC.
By its counsel,

____
Charles Keizer, Torys LLP

____
Arlen Sternberg, Torys LLP

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One's Vice-President of Regulatory Affairs and Chief Risk Officer, Frank D'Andrea hereby certifies for and on behalf of Hydro One that:

1. I am a senior officer of Hydro One;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised on February 11, 2016); and
3. The evidence submitted in support of Hydro One's 2020-2022 transmission application (EB-2019-0082) is accurate, consistent and complete to the best of my knowledge.

DATED this 21st day of March, 2019.

FRANK D'ANDREA

Witness: Frank D'Andrea

GLOSSARY

"AA" refers to "Asset Analytics".

"AACE" refers to the "American Association of Cost Engineers" which is the group that developed an industry established cost estimating framework that Hydro One uses.

"ABCBs" refers to "Air Blast Circuit Breakers" being phased out by industry due to poor performance, high maintenance costs and technological obsolescence.

"Act" refers to the *Ontario Energy Board Act,1998.*

"AFUDC" refers to "Allowance for Funds Used During Construction".

"AM" refers to "Asset Management".

"Application" refers to this application EB-2019-0082 by Hydro One to the OEB for an order or orders made pursuant to section 78 of the *Act* approving rates for the transmission of electricity.

"ARA" refers to "asset risk assessment".

"B2M LP" refers to the B2M Limited Partnership, which is an Ontario transmitter.

"B&V" refers to "Black & Veatch" which was commissioned to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution.

"BCA" refers to "Building Condition Assessments".

"BCG" refers to "Boston Consulting Group" which assisted Hydro One in setting benchmarking and asset condition/management process objectives.

"BES" refers to the "bulk electric system", which NERC defines as including all transmission facilities greater than 100 kV, which encompasses the vast majority of Ontario's (and Hydro One's) transmission facilities.

"BGIS" refers to "Brookfield Global Integrated Solutions" .

"BGIS Agreement" refers to an agreement made with PWU in regards to outsourced work made on January 1, 2015.

"BJCC" refers to "Brookfield Johnson Controls Canada" which is a joint venture between Johnson Controls and BGIS.

"BTU" refers to "Building Trades Unions".

"BUCC" refers to the Ontario Grid Control Centre's "Back Up Control Centre" which is maintained in accordance with NERC standard Emergency Operating Procedure, EOP-008-2 "Loss of Control Centre Functionality" and the IESO Market Rules.

"BVLOS" refers to "Beyond Visual Line of Site".

"C" refers to "custom capital factor".

"CAA" refers to the IESO's "Connection Assessment and Approval".

"CapEx" refers to **"**capital expenditures".

"Capital Expenditure Plan" refers to Hydro One's capital expenditure plans for its transmission system for the period of 2020-2024. The capital expenditure plan is the product of the investment planning process and asset management strategies.

"Capital Program Performance Report" refers to a report directed by the OEB describing performance in the execution of the capital program relative to plan. It is provided in Attachment 1 of Exhibit C, Tab 2, Schedule 1.

"CBM" refers to "condition-based maintenance".

"CCA" refers to "capital cost allowance".

"CCFS" refers to "common corporate functions and services".

"CCRA" refers to "Connection Cost Recovery Agreements", which are based on Hydro One's connection procedures that outline a customer's capital contribution towards connection.

"CDM" refers to "conservation and demand management".

"CDPP" refers to the "Customer Delivery Point Performance" standard.

"CEA" refers to **"**Canadian Electricity Association".

"CEATI" refers to the "Centre for Energy Advancement through Technological Innovation", which is a Canada based external researcher.

"CIP" refers to the "critical infrastructure program" relating to key sites subject to NERC Critical Infrastructure Program requirements.

"CIR" refers to the "custom incentive rate-setting" option.

"CME" refers to the "Canadian Manufacturers and Exporters" which is an association of Canadian manufacturers and exporters.

"CMMS" refers to the "Computerized Maintenance Management System".

"COTS" refers to "commercial-off-the-shelf".

"CP" refers to "coincident peak".

"CPI" refers to the "Consumer Price Index".

"CRTC" refers to the **"**Canadian Radio-television Telecommunications Commission", which is Canada's federal regulator for radio, television and telecommunications.

"CSA" refers to the "Canadian Standards Association".

"CUSW" refers to the "Canadian Union of Skilled Workers".

"CWIP" refers to "construction work in progress".

"CVA" refers to "current value assessment", which is a valuation method used by Hydro One for municipal taxes in municipalities.

"DBRS" refers to the "Dominion Bond Rating Service".

"DC Plan" refers to the "Defined Contribution Pension Plan".

"DFL" refers to "Dual Function Line" assets.

"DGA" refers to "dissolved gas".

"discretionary" refers to all work that is not non-discretionary. Work within the discretionary category includes work that is non-deferrable because of the poor condition of the asset.

"DPs" refers to "Delivery Points", which are boundaries between the electricity systems of Hydro One and transmission-connected customers.

“DRO” refers to “Draft Rate Order”

“DSP” refers to “Distribution System Plan”.

“EAR” refers to the “Expenditure Authority Register”.

“ECA” refers to “Economic Cost Adjustment”, which is a government published index that reflects movements in a broad-based consumer-focused price inde**x** as well as “Environmental Compliance Approvals”, which are issued by the Ministry of the Environment, Conservation and Parks.

“Elenchus” refers to “Elenchus Research Associates.”

“ELT” refers to the Executive Leadership Team, which is Hydro One's most senior level of management.

“EOL” refers to “end of life”.

“EPC” refers to “Engineer, Procure and Construct”.

“EPRI” refers to the “Electric Power Research Institute”, which is an independent, non-profit organization for public interest energy and environmental research that conducts research, development and demonstration projects. EPRI conducted several analyses on behalf of Hydro One which are provided as Attachments to Section 1-4 of the TSP (Exhibit B, Tab 1, Schedule 1).

“EPSCA” refers to the “Electrical Power Systems Construction Association” trade union.

“ERO” refers to the “Electricity Reliability Organization”.

“ERP” refers to “enterprise resource planning” or “Emergency Response Plans”.

“ESOP” refers to the “Employee Share Ownership Plan”.

“ESL” refers to the “expected service life”, which is the average time duration in years that an asset can be expected to operate under normal system conditions.

“ETS” refers to the “Export Transmission Service”.

“FERC” refers to the American “Federal Energy Regulatory Commission”.

"Filing Requirements" refers to the OEB's *Filing Requirements for Electricity Transmission Applications* (February 11, 2016) and may also include the OEB's *Consolidated Distribution System Plan Filing Requirements* (July 12, 2018), and the OEB's *Handbook for Utility Rate Applications* (October 13, 2016).

"Fleet" refers to Transportation and Work equipment**.**

"FNEI" refers to "Five Nations Energy Inc.", the lead transmitter for the North of Moosonee region.

"FSCO" refers to the "Financial Services Commission of Ontario".

"GBV" refers to "Gross Book Value".

"GC" refers to a "Generation Line/Transformation Connection".

"GIS" refers to "gas insulated switchgear".

"GLPT" refers to **"**Great Lakes Power Transmission", which is the former lead transmitter in the East Lake Superior Region.

"Handbook" refers to the OEB's *Handbook for Utility Rate Applications* (October 13, 2016).

"HELM" refers to the "hourly electric load model".

"HSEMS" refers to the "Health and Safety Management System".

"HV" refers to "high voltage" (115-500 kV).

"HVAC" refers to "heating ventilation and air-conditioning".

"Hydro One" refers to the transmission business of "Hydro One Networks Inc.", which is the subsidiary of Hydro One Inc. that owns and operates the province-wide transmission system and rural distribution system in Ontario.

"Hydro One SSM" refers to "Hydro One Sault Ste. Marie" which is the lead transmitter for East Lake Superior Region held under Hydro One Limited.

"Hydro One Telecom Inc." refers to a subsidiary of Hydro One Inc. operating telecommunications services.

"I" refers to "Inflation Factor".

“ICI” refers to the “industrial conservation initiative”, which is a policy that incentivizes large customers to reduce their consumption during peak hours.

“IEEE” refers to the “Institute of Electrical and Electronic Engineers”.

“IED” refers to the “Intelligent Electronic Devices”, which are microprocessor based protection systems that enable post-fault technical analyses.

“IESO” refers to the “Independent Electricity Systems Operator”.

“IHS” refers to “Information Handling Services”

“INAC” refers to the Federal Department of Indigenous and Northern Affairs, Canada.

“Inergi” refers to “Inergi LP”, which is a company Hydro One outsources a variety of services to. Previously Inergi operated Hydro One's call centre before Hydro One brought back the call center “in-house” in March 2018.

“INPO” refers to the “Institute of Nuclear Power Operations”

“Investment Planning” refers to the process through which Hydro One identifies and prioritizes capital and OM&A investments.

“IPO” refers to the “Initial Price Offering” of Hydro One Limited shares to public markets in 2015.

“IPP” refers to the “Investment Planning Process”, defined above.

“IR” refers to “Incentive Rate-Setting”.

“IRG” or “Innovative” refers to “Innovative Research Group”, which is a third party research and consultation firm that surveyed transmission-connected customer’s preferences.

“IRRP” refers to the “Integrated Regional Resource Plan Process”, which involves identifying, evaluating and integrating potential wires and non-wires solutions at the regional or sub-regional level.

“ISD” refers to “Investment Summary Documents”, which detail specifics for each material capital investment with spending greater than $3 million in any one year.

“ISOC” refers to the “Integrated System Operating Centre”.

“IT” refers to “Information Technology”.

“ITMC” refers to the “Integrated Telecom Management Center”.

“IVCT” refers to the “Integrated Voice Communications and Telephony System”.

“LAC” refers to a “Local Advisory Committee”, which is made up of representatives from public and various interested customer and stakeholder groups if community input and broader engagement is needed in regional planning.

“LAN” refers to “Local Area Networks”.

“LAR” refers to the “Land Assessment Remediation” program, which focuses on the mitigation and remediation of historical contamination from transmission station sites and real estate facilities that may pose risk to the public and/or Hydro One staff.

“LC” refers to “Line Connection”.

“LCC” refers to “Local Control Computers”.

“LDA” refers to the large distribution end-use customers with peak demand above a 2 MW demand threshold.

“LDCs” refers to “Local Distribution Companies”, which own and operate distribution systems that transmit electricity to end-use customers.

“Line Connection Service” refers to a transmission service for use of facilities that step down the voltage from above 50 kV to below 50 kV.

“LMC” refers to “Local Maintenance Computers”.

“LOB” refers to a “line of business”, which is a corporate business unit at Hydro One.

“LTEP” refers to the “Long-Term Energy Plan”, a document created by the Ontario Government that directs long-term planning of the Province's electricity system.

“LTIP” refers to “Long Term Incentive Plan”.

“LVSG” refers to “low voltage switchgear”.

“MACD” refers to the “Market Assessment and Compliance Division”, which is an IESO division that sets reliability standards.

“MCP” refers to management employees not represented by unions.

“Metsco” refers to “Metsco Energy Solutions”, which assisted Hydro One in benchmarking its asset condition/management processes.

“MFA” refers to “Minor Fixed Assets”, which include desktops, laptops, printers, plotters, rugged tablets and mobile devices which are used to provide information and capability of Hydro One's enterprise systems to employees.

“Microwave radio systems” refers to a Power System Telecom asset.

“MMP” refers to a “Metered Market Participant”.

“MOECP” refers to the Ontario “Ministry of the Environment, Conservation, and Parks”.

“MSO” refers to “Mid-Span Openers”, which are a type of line-switch.

“MSP” refers to “Meter Service Provider”.

“MTN” refers to the “Medium Term Note” program, which provides ready access to issue debt with a term greater than one year into the Canadian debt capital markets.

“MV” refers to “medium voltage” (44-12.5 kV).

“MVIT” refers to approximately 3,000 “Medium Voltage Instrument Transformers”.

“NACE” refers to the “National Association of Corrosion Engineers”.

“NBV” refers to “Net Book Value”.

“NEB” refers to the “National Energy Board”, which is the Federal energy regulator.

“NERC” refers to the “North American Reliability Corporation”, which sets the reliability standards that ensure the integrity of the interconnected North American Bulk Electricity Systems. NERC standards are enforced by the IESO.

“Network buildings” refers to buildings and related site infrastructure that exclusively house transmission network equipment.

“Network Connection Service” refers to a transmission service for use of assets built for the common benefit of all customers.

"NIBT" refers to "net income before tax".

"NMS" refers to **"**Network Management System".

"NOMS" refers to "Network Outage System".

"Non-discretionary work" refers to work that must be performed in order to comply with applicable laws or external requirements, to keep the public and workers safe or to avoid a material cost that might arise if the project was delayed.

"NPCC" refers to the "Northeast Power Coordinating Council", which develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability.

"NPV" refers to "Net Present Value".

"NRC" refers to the "National Research Council Transmission Station".

"NSC" refers to "Network Service Charge".

"NT" refers to "neutralizing transformers".

"NWBTL" refers to the "North West Bulk Transmission Line".

"OCBs" refers to "Oil circuit breakers", which are an older technology that rely on complex mechanical systems for operation and large amounts of oil for insulation.

"OEB" or "the Board" refers to the "Ontario Energy Board", which is the regulator of electricity and natural gas in Ontario.

"OEFC" refers to the "Ontario Electricity Financial Corporation", which was established following the dissolution of Ontario Hydro and is primarily responsible for Ontario Hydro's debt and other financial obligations.

"OGCC" refers to the "Ontario Grid Control Centre", where Hydro One operates its transmission system and manages responses to trouble calls from a centralized operations facility.

"OH Cap Rates" refers to "Overhead Capitalization Rates".

"OHSAS" refers to the "Occupational Health and Safety Assessment Series".

“OM&A” refers to “Operations, Maintenance and Administration”.

“OPG” refers to “Ontario Power Generation”.

“OPGW” refers to “optical ground wire”, which has strands of fibre embedded inside of the shieldwire mounted on top of high-voltage transmission structures.

“OPEBs” refers to “Other Post-Employment Benefit Costs”.

“OPO” refers to the “Ontario Planning Outlook”, which is the IESO provided outlook of demand.

“ORTAC” refers to “Ontario Resource and Transmission Assessment Criteria”, which are IESO guidelines that outline key requirements for transmission planning for reliability.

“PALC” refers to “Programmable Auxiliary Logic Controller”.

“PCB” refers to “Polychlorinated Biphenyls”, which is a chlorine compound used as dielectric and coolant fluid in electrical equipment.

“PIs” refers to “Performance Indicators”.

“PILs” refers to “Payment in Lieu of Taxes”.

“PLC” refers to “Power Line Carrier Systems”, which are used by Hydro One to provide an alternative means of dependable communications between stations.

“Planning period” is the minimum five year term for a custom incentive-rate setting plan, as required by the OEB’s Filing Requirements. The planning period for Hydro One’s Application is 2020 – 2024.

“PMs” refers to “Project Delivery Managers”.

“PMRS” refers to the “Provincial Mobile Radio System”.

“PQ” refers to the customer “Power Quality” program.

“Prior Proceeding” refers to OEB proceeding EB-2016-0160, in which the OEB heard Hydro One’s application for transmission revenue requirement for 2017 and 2018.

“Progressive Productivity Placeholder” refers to the numerical adjustment made in the business plan resulting from Progressive Productivity.

"Progressive Productivity (Defined)" refers to proposed progressive productivity savings that are in the process of being allocated to specific capital projects and work programs.

"Progressive Productivity (Undefined)" are progressive productivity savings which will be allocated to either OM&A projects or work programs as initiatives evolve.

"PSE" refers to "Power Systems Engineering" which is a consultant company that completed benchmarking analyses to inform Hydro One's proposed Custom IR mechanism.

"PSIT" refers to Power System Information Technology".

"PSLUP" refers to the "Provincial Secondary Land Use Program".

"PSMC" refers to "Power System Monitoring & Control".

"PSMP" refers to the "Protection System Maintenance Program" in accordance to NERC PRC-005 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance.

"PSR" refers to "Programmable Synchrocheck Relays".

"PSTS" refers to "power system telecom services", which are used for station-to-station telecommunications.

"PTS" refers to the "Provincial Transmission Service".

"PTS-L" refers to a "Line Connection Service Rate".

"PTS-N" refers to "Network Service Rate".

"PTS-T" refers to "Transformation Connection Service Rate".

"PWU" refers to the "Power Workers Union".

"R" refers to "Resistance", which is the measure of difficulty for electricity to pass through a conductor.

"R1 customers" refers to medium density residential customers of Hydro One's distribution business.

"R2 customers" refers to low density residential customers of Hydro One's distribution business.

“RCI” refers to “Revenue Cap Index”.

“RCM” refers to “Reliability Centered Maintenance”.

“RD&D” refers to “Research, Development and Demonstration” programs.

“RIP” refers to the “Regional Infrastructure Plan” process, which is the final phase of the regional planning process and involves confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle (including end of life transmission asset needs that may influence a solution to address broader regional needs); and development of a wires plan to address the needs.

“ROE” refers to “Return on Equity”.

“ROW” refers to “right of way” areas where Hydro One assets are granted a legal right to pass along uninhibited.

“RRF” refers to the “Renewed Regulatory Framework”, which is the OEB framework introduced in 2012 to balance investment needs of the sector with customer cost concerns.

“RRM” refers to the **“**Reliability Risk Model”.

“RRR” refers to the “Reporting and Record-keeping Requirements” which are the OEB’s reporting requirements for the utilities that it regulates.

“RSCC” refers to the “Reliability Standards Compliance Committee”, which oversees Hydro One's compliance with reliability standards.

“RTSR” refers to the “Retail Transmission Service Rates”.

“SA” refers to “System Access” or “Scoping Assessment”.

“SCADA” refers to “Supervisory Control and Data Acquisition”.

“SDLC” refers to “Systems Development Life Cycle” methodologies, which are largely based on industry standards and inform strategic decisions to conduct system upgrades.

“SDOC” refer to Sustaining, Development, Operations and Common Corporate Costs and Other Costs. These are the four categories of cost expenditure that are utilized by Hydro One to categorize its spending.

“SF6”refers to “Sulfur Hexafluoride” is a common and effective dielectric medium used in a large portion of the breaker fleet.

"Shared Assets" refers to common shared assets.

"SL" refers to an assigned "Support Level" designation when an IT application is placed into service.

"Society" refers to the "Society of United Professionals" (formerly "Society of Energy Professionals"), which represents a large number of Hydro One employees.

"SONET" refers to "Synchronous Optical NETworking".

"SS" refers to "Station Services".

"STIP" refers to the "Short Term Incentive Plan".

"System unavailability" refers to a measure that examines the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages.

"TC" refers to "Transformation Connection".

"TCB study" refers to the Total Cost Benchmarking" independent study used to benchmark Hydro One against peer utilities.

"T-CCOS" refers to "Transmission Consultative Committee on Outage Statistics".

"Test period" refers to the three year period from 2020 to 2022 for which Hydro One's Application is requesting approval of its transmission revenue requirement.

"TFP" refers to "total factor productivity".

"THESL" refers to "Toronto Hydro-Electric System Limited", which is colloquially known as "Toronto Hydro" and is the LDC for the City of Toronto.

"Tier 1 Productivity" refers to productivity improvements that will result in actual cost savings.

"Tier 2 Productivity" refers to productivity improvements that will result in more work for the same cost, excluded from reporting on corporate scorecards.

"Transformation Connection Service" refers to a transmission service for all other assets not included in Network Connection or Line Connection transmission services pools-generally those assets built for use by a specific customer(s).

"T-SAIDI" refers to the "Transmission System Average Interruption Duration Index", which measures the average duration of sustained DP interruptions – those greater than one minute in duration – and is used as an indicator of the average minutes of unplanned interruptions that customers experience per DP in the year.

"T-SAIFI-M" refers to the "Transmission System Average Interruption Frequency Index – Momentary Interruption", which is the average frequency of DP momentary interruptions – those less than one minute in duration – and is used as an indicator of the average number of unplanned momentary interruptions that customers experience per DP in the year.

"T-SAIFI-S" refers to the "Transmission System Average Interruption Frequency Index – Sustained Interruption", which measures the average frequency of DP sustained interruptions – those greater than one minute in duration – and is used as an indicator of the average number of unplanned sustained interruptions that customers experienced per DP in the year.

"TSC" refers to the "Transmission System Code", which is the OEB document outlining conditions, obligations and codes of transmission service in Ontario.

"TSOG" refers to "Transmission System Outage Groupings", which is a service to bundle outages where appropriate, to effectively plan and better align with interconnected customers.

"TSO" refers to the "Transmission System Outage" process, which is an OGCC process to coordinate multiple work activities on the same equipment during a single outage.

"TSP" refers to the "Transmission System Plan", which provides a detailed explanation of Hydro One's proposed capital investment plan for its transmission system in respect of the 5-year planning period from 2020 to 2024.

"TSSA" refers to "Technical Standards and Safety Authority".

"TWE" refers to "Transport and Work Equipment".

"Tx OMA" refers to "Transmission Operations, Maintenance and Administration".

"UCC" refers to "undepreciated capital costs."

"Unsupplied Energy" refers to the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points.

Witness: Frank D'Andrea

"UPC" refers to "Unit Price Catalogue".

"US GAAP" refers to the "United States Generally Accepted Accounting Principles", which Hydro One adopted under the OEB's orders.

"USofA" refers to "Uniform System of Accounts".

"UTR" refers to "Uniform Transmission Rates".

"UWPC" refers to the "Utility Work Protection Code".

"V5" refers to "NERC CIP Version 5" cyber security requirements to BES.

"V6" refers to "NERC CIP Version 6" cyber security requirements to BES.

"VOR" refers to a **"**Vendor of Record".

"VPN" refers to a "Virtual Private Network".

"WMS" refers to "Wholesale Meter Service", which is a transmission service for parties that purchase electricity in the IESO-administered markets or directly from a generator.

"WRDI" refers to the "worst reasonable direct impact" of not making an investment and, if available, the additional costs associated with such an event occurring.

"X" refers to the "Productivity Factor", which is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.

COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY TRANSMITTERS

Hydro One has prepared this Application in alignment with the OEB's guidance in its *Filing Requirements for Electricity Transmission Rate applications* (February 11, 2016) ("Transmission Filing Requirements"). Hydro One has changed the organization of its content from prior applications to better align with Chapter 2 of the Transmission Filing Requirements ("Chapter 2"). To assist the OEB in its review of the Application, Hydro One has prepared a checklist of the Transmission Filing Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1 to this Exhibit in the worksheet labelled "*Transmission Filing Reqs*".

Where applicable, Hydro One has incorporated the Chapter 2 appendices from the *Filing Requirements for Electricity Distributors* to support its evidence. These are listed in Attachment 1 to this Exhibit and are provided throughout the Application.

Section 2.4 of Chapter 2 states that transmitters may wish to refer to Chapter 5 of the OEB's *Filing Requirements for Electricity Distributors, Consolidated Distribution System Plan Filing Requirements* ("DSP Requirements") for further guidance on the content and structure of a Transmission System Plan ("TSP").[1] Hydro One has adopted the DSP Requirements, as applicable, to guide the preparation of its TSP including the adoption of the OEB's standard capital investment categories of: System Access, System Renewal, System Service and General Plant.

[1] The TSP is found in Exhibit B, Tab 1, Schedule 1 of the Application.

As required by Chapter 2, Hydro One's TSP covers a five year planning period (2020-2024). Hydro One only seeks approval of its revenue requirement for a three year test period (2020-2022). This test period is consistent with the OEB's direction to allow for Hydro One to file a single application for both distribution rates and transmission revenue requirement with a test period commencing in 2023.[2]

In preparing this Application, Hydro One also looked beyond transmission-specific filing requirements to ensure it was consistent with the expectations of a Custom Incentive-Rate Setting ("IR") application under the OEB's Renewed Regulatory Framework ("RRF") as described in the OEB's *Handbook for Utility Rate Applications* ("the Handbook"), dated October 13, 2016. As listed below, Hydro One's Application meets all the requirements for a Custom IR filing outlined on pages 25 and 26 of the Handbook:

1. <u>Term:</u> Though less than the minimum term of five years that is articulated in the Handbook, Hydro One's Custom IR term of 3-years is consistent with the guidance provided by the OEB in its March 16, 2018 letter as it will allow for a combined transmission and distribution filing with a test period commencing in 2023.

2. <u>Index for the Annual Rate Adjustment:</u> The proposed Revenue Cap Index includes specific financial incentives for continuous improvement through a custom productivity factor and is supported by third-party empirical evidence as outlined in Exhibit A, Tab 4, Schedule 1.

[2] In a letter dated March 16, 2018, the OEB directed Hydro One to file its transmission revenue requirement application for a four year test period from 2019 to 2022 and file a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

3. Benchmarking: Hydro One's application contains 17 benchmarking studies and condition analyses which are discussed in Section 1.4 of the TSP, in Exhibit A, Tab 4, Schedule 1, and in Exhibit F, Tab 4, Schedule 1.

4. Performance Metrics: Hydro One has proposed an evolved transmission scorecard in Section 1.5 of the TSP. The proposed metrics align with the RRF outcomes of customer focus, operational effectiveness, financial performance and public policy responsiveness and the provided targets indicate Hydro One's commitment to continuous improvement.

5. Updates: Hydro One's proposal does not contain annual updates after the 2020 revenue requirement is approved.

6. Protecting Customers: Exhibit A, Tab 4, Schedule 1 outlines Hydro One's proposed Earnings Sharing Mechanism and Capital In-Service Variance Account which share the benefit of productivity improvements with customers during the term and provide rate payers with protection from utility earnings that become excessive. Hydro One has also included expected productivity savings in capital and operations, maintenance and administration expenses totaling approximately $704 million over the TSP planning period, approximately $370 million of which is expected during the test period. Hydro One bears the risk of delivering on these savings, which are described in Section 1.6 of the TSP.

Transmission Filing Requirements Checklist

Hydro One Networks Inc. (Transmission)

EB-2019-0082

Date: February 11, 2016

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
GENERAL REQUIREMENTS			
Ch 1, p 2	Certification that the evidence filed is accurate, consistent and complete	**Yes**	Exhibit A, Tab, 2, Schedule 1, Attachment 1
3	Confidential Information - Practice Direction has been followed	**Yes**	
Ch 2, p 4	Provide Chapter 2 appendices that are applicable to their transmission applications	**Yes**	
4	Written direct evidence is to be included before data schedules	**Yes**	
4	Average of the opening and closing fiscal year balances must be used for items in rate base	**Yes**	Exhibit C, Tab 1, Schedule 1
4	Total capitalization (debt and equity) must equate to total rate base	**Yes**	
4	Data for the following years, at a minimum, must be provided: Test year = prospective rate year; Bridge year = current year; Four most recent historical years; Most recent OEB-approved test year	**Yes**	
4	Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year o the proposed rate term, and benchmarking evidence supporting the cost forecasts	**Yes**	
4	Documents are to be provided in bookmarked and text-searchable Adobe PDF format	**Yes**	
4	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical	**Yes**	
6	Materiality threshold	**Yes**	TSP Section 3.3
6	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing	**Yes**	Exhibit A, Tab 6, Schedule 1
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Executive Summary			
Ch 2, p 8	Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives	**Yes**	Exhibit A, Tab 3, Schedule 1
8	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE including customer feedback reflected in the transmitter's objectives,	**Yes**	Exhibit A, Tab 3, Schedule 1
8	Revenue Requirement - request, changes from previous revenue requirement and drivers of change	**Yes**	Exhibit A, Tab 3, Schedule 1
8	Budgeting Assumptions - Economic overview	**Yes**	Exhibit A, Tab 3, Schedule 1
8	Load Forecast - Load growth and forecast methods	**Yes**	Exhibit A, Tab 3, Schedule 1
9	TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved	**Yes**	Exhibit A, Tab 3, Schedule 1
9	Rate Base - Request for test years and change from last OEB approved	**Yes**	Exhibit A, Tab 3, Schedule 1
9	Performance and Reporting - Proposed scorecard	**Yes**	Exhibit A, Tab 3, Schedule 1
9	OM&A - Request for test years, changes from last OEB approved and drivers of change	**Yes**	Exhibit A, Tab 3, Schedule 1
9	Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology	**Yes**	Exhibit A, Tab 3, Schedule 1
9	Cost Allocation + Rate Design - Summary of how costs are allocated to rate pools	**Yes**	Exhibit A, Tab 3, Schedule 1
10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts	**Yes**	Exhibit A, Tab 3, Schedule 1
10	Bill Impacts - Summary of impacts at wholesale level and for typical retail customers	**Yes**	Exhibit A, Tab 3, Schedule 1

Customer Engagement			
Ch 2, p 10	Customer engagement process and activities	**Yes**	Exhibit A, Tab 7, Schedule 2; TSP Section 1.3
10	Customer needs including end-use load customers and generator customers	**Yes**	Exhibit A, Tab 7, Schedule 2; TSP Sections 1.2 and 1.3
10	How the application responds to customer needs	**Yes**	TSP Sections 2.1 and 3.2
10	Customer satisfaction surveys	**Yes**	TSP Section 1.3
10	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence	**Yes**	Exhibit A, Tab 7, Schedule 1, Attachment 1
11	Responses to letters of comment	**Yes**	
Financial Information			
Ch 2, p 11	Non-consolidated Audited Financial Statements for 2 most recentyears (i.e. 3 years of historical actuals)	**Yes**	Exhibit A, Tab 6, Schedule 2
11	Detailed reconciliation of AFS with regulatory financial results	**Yes**	Exhibit A, Tab 6, Schedule 4
11	Annual Report and MD&A for most recent year of parent company	**Yes**	Exhibit A, Tab 6, Schedule 6
	Rating Agency Reports	**Yes**	Exhibit A, Tab 6, Schedule 3
11	Prospectuses & information circulars for recent and planned public offerings	**Yes**	Exhibit A, Tab 6, Schedule 5
Administration			
Ch 2, p 11	Table of Contents	**Yes**	Exhibit A, Tab 1, Schedule 1
11	Statement identifying customers materially affected by the application	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Internet address for viewing of application	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Identification of legal representation	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Requested effective date	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Bill impacts for typical Ontario residential customer an Ontario General Service customer	**Yes**	Exhibit A, Tab 3, Schedule 1
12	Form of hearing requested (written or oral)	**Yes**	Exhibit A, Tab 2, Schedule 1
12	List of approvals requested including accounting orders	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	**Yes**	Exhibit A, Tab 2, Schedule 1
12	Changes in tax status	**Yes**	Exhibit F, Tab 7, Schedule 2
12	Existing Accounting Orders	**Yes**	Exhibit H, Tab 1, Schedule 1
12	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	**Yes**	TSP Section 1.1
12	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	**Yes**	Exhibit A, Tab 5, Schedule 1
13	The Accounting Standard used and when it was adopted	**Yes**	Exhibit A, Tab 6, Schedule 1
13	Deviations from filing requirements, if any	**N/A**	
13	Changes to methodologies used in previous applications	**Yes**	Exhibit A, Tab 6, Schedule 1
13	Confirmation that accounting treatment is segregated for non-regulated business	**Yes**	Exhibit A, Tab 6, Schedule 1
13	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application	**Yes**	Exhibit A, Tab 2, Schedule 4

EXHIBIT 2 - Transmission System Plan			
General			
Ch 2, p 13	Refer to Chapter 5 of the Distribution Filing Requirements	**Yes**	
13	The strategic plan for the utility and investment strategy	**Yes**	Exhibit A, Tab 3, Schedule 1, Attachment 1 TSP Section 2.1
13	The longer term economic and planning assumptions	**Yes**	TSP Section 2.1
13	The asset management plan	**Yes**	TSP Section 2.1 TSP Section 3.1
13	A description of how investments are prioritized and selected	**Yes**	TSP Section 2.1
13	A discussion of transmission investments identified in the regional planning process	**Yes**	TSP Section 1.2 and Attachments
13	Highlights of recent and proposed investments and their fit with the strategic plan	**Yes**	TSP Sections 1.1 and 3.2
13	A description of how the needs of customers and overall system planning policy objectives are being reflected	**Yes**	TSP Section 2.1
13	Commitments stemming from the Long Term Energy Plan or the Conservation First policy, and consideration for the OEB's statutory objectives, including facilitating a smart grid and the connection of renewable	**Yes**	TSP Section 1.7
Asset Management Plan			
Ch 2, p 14	Asset management policy, strategy and objectives	**Yes**	TSP Section 2.1 TSP Section 2.3
14	Inventory and assessment of the condition of capital assets (by class and inclusion in BES), how this informs plan for capital expenditures and maintenance expenditures	**Yes**	TSP Section 2.2
14	Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	**Yes**	Exhibit D, Tab 3, Schedule 1
Regional Considerations			
Ch 2, p 14	Regional planning process demonstrating that regional considerations have been considered and addressed	**Yes**	TSP Section 1.2
14	Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP	**Yes**	TSP Section 1.2
14	Identify investments spanning more than one region	**Yes**	TSP Section 1.2
Coordinated Planning with Third Parties			
Ch 2, p 15	Description of the consultation including: the purpose of the consultation; whether the transmitter initiated the consultation or was an invitee; participants in the consultation; deliverables and impact on plan	**Yes**	TSP Sections 1.2 and 1.3
Capital Expenditures			
Ch 2, p 16	Summary of capital expenditures over the past five historical years including the bridge year and five future years including the test year(s), showing treatment of contributed capital and additions and deductions from Construction Work in Progress	**Yes**	TSP Section 3.3
16	Material Investments - For projects and programs: - a description of the need, scope and purpose of the project or program - customer attachments - load and capital costs - cost-benefit analysis - identify where "leave to construct" required or project is necessary to comply with a licence condition	**Yes**	TSP Section 3.3, Attachments: Investment Summary Documents
16	Drivers of capital expenditure increases for the test year(s)	**Yes**	TSP Section 3.2
16	The basis for the estimated budget for the project or program	**Yes**	TSP Section 3.2 TSP Section 3.3, Attachments: Investment Summary Documents
16	For the balance of capital expenditures, describe components of capital expenditure and provide a reconciliation of capital components to total capital budget	**Yes**	TSP Section 3.3
17	Written explanation of capital expenditure variances	**Yes**	Exhibit C, Tab 2, Schedule 1, Attachment 1
17	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	**Yes**	Exhibit C, Tab 8, Schedule 1
17	Cost benchmarking studies or utility cost comparisons	**Yes**	TSP Section 1.4 and Attachments
17	Continuous improvement or efficiency gains, how they will be achieved and benefit customers	**Yes**	Exhibit A, Tab 4, Schedule 1 TSP Section 1.6
17	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income	**Yes**	Exhibit A, Tab 4, Schedule 1

EXHIBIT 3 - Rate Base			
Overview			
Ch 2, p 17	Opening and closing balances and the averages thereof gross assets and accumulated depreciation Rate base shall include an allowance for working capital Rate base must be supported by historical actuals, bridge year and test years	**Yes**	Exhibit C, Tab 1, Schedule 1
18	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual Hist. Act. vs. preceding Hist. Act. Hist. Act. vs. Bridge Bridge vs. Test	**Yes**	Exhibit C, Tab 4, Schedules 2 to 5
18	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	**Yes**	Exhibit C, Tab 1, Schedule 1 Exhibit C, Tab 4, Schedule 4
19	Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format.	**Yes**	Exhibit C, Tab 1, Schedule 1 Exhibit C, Tab 4, Schedule 4
Gross Assets - PP&E and Accumulated Depreciation			
Ch 2, p 19	Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses	**Yes**	Exhibit C, Tab 4, Schedule 4
19	Detailed breakdown by major plant account for each functionalized plant item; For the test year(s), each plant item must be accompanied by a description.	**Yes**	Exhibit C, Tab 4, Schedule 4
19	Detailed breakdown of the in-service capital additions for the test year(s)	**Yes**	Exhibit C, Tab 1, Schedule 1
19	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	**Yes**	Exhibit C, Tab 4, Schedule 4
Allowance for Working Capital			
Ch 2, p 19	Working Capital - Lead/Lag Study	**Yes**	Exhibit C, Tab 5, Schedule 1 and Attachment 1
19	Lead/Lag Study - leads and lags measured in days, dollar-weighted	**Yes**	Exhibit C, Tab 5, Schedule 1 and Attachment 1
19	For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources.	**Yes**	Exhibit C, Tab 5, Schedule 1 and Attachment 1
Customer Connection and Cost Recovery Agreements			
Ch 2, p 20	The transmitter should show customer contribution amounts separately as an offset to rate base.	**Yes**	Exhibit C, Tab 7, Schedule 1
20	Agreements reviewed on reaching a fifth anniversary and aggregated estimate of total expected true-up contributions and proceeds from bypass agreements	**Yes**	Exhibit C, Tab 7, Schedule 1
20	Financial and regulatory accounting treatment of true-up proceeds.	**Yes**	Exhibit C, Tab 7, Schedule 1
Capitalization Policy			
Ch 2, p 20	Capitalization policy, including changes since the last revenue requirement application	**Yes**	Exhibit C, Tab 8, Schedule 2
20	Overhead costs on self-constructed assets	**Yes**	Exhibit C, Tab 8, Schedule 2
20	Identification of burden rates and burden rates prior to changes, if any	**Yes**	Exhibit C, Tab 9, Schedule 1

Capital Module			
Ch 2, p 21	Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the Transmission System Plan; intended to come into service during the index period; Involve costs that the transmitter cannot manage through the revenue established through the index	**N/A**	
21	The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.	**N/A**	
EXHIBIT 4 - Service Quality and Reliability Performance and Reporting			
Proposed Scorecard			
21	Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant measures	**Yes**	Exhibit D, Tab 1, Schedule 1 TSP Section 1.5
Reliability Performance			
22	Reliability performance measures: transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability	**Yes**	Exhibit D, Tab 2, Schedule 1 and Attachment 1
22	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	**Yes**	Exhibit D, Tab 2, Schedule 1 and Attachment 1
22	Compare system performance with other systems both nationally and internationally	**Yes**	Exhibit D, Tab 2, Schedule 1
Compliance Matters			
22	Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance	**Yes**	Exhibit D, Tab 3, Schedule 1
EXHIBIT 5 - Operating Revenue			
Load and Revenue Forecasts			
23	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	**Yes**	Exhibit E, Tab 3, Schedule 1
23	Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses	**Yes**	Exhibit E, Tab 3, Schedule 1
23	Detailed CDM forecast, with impact of CDM shown on the load forecast for each of the three rate pools. The applicant must also indicate how the forecast reflects IESO CDM forecasts and targets in the load forecast	**Yes**	Exhibit E, Tab 3, Schedule 1
23	Impact of forecast embedded generation on the transmission system load accounted for	**Yes**	Exhibit E, Tab 3, Schedule 1
Accuracy of Load Forecast and Variance Analyses			
23	Demonstrate five year historical accuracy by providing schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for: - Historical OEB-approved; - Historical actual for the past 5 years; - Historical actual for the past 5 years – weather normalized; - Bridge year; - Bridge year – weather normalized; - Test year	**Yes**	Exhibit E, Tab 3, Schedule 1
24	Analyses and discussion for volumes, revenues, customer/connections count and total system load: - Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences; - Historical OEB-approved vs. historical actual; - Historical OEB-approved vs. historical actual – weather normalized; - Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years); - Historical actual – weather normalized vs. bridge year – weather-normalized; - Bridge year – weather-normalized vs. test year(s)	**Yes**	Exhibit E, Tab 3, Schedule 1

24	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	**Yes**	Exhibit E, Tab 3, Schedule 1, Attachment 1
Other Revenue			
24	Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons	**Yes**	Exhibit E, Tab 2, Schedule 1 and Attachment 1
24	How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges	**Yes**	Exhibit E, Tab 2, Schedule 1
24	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs	**Yes**	Exhibit E, Tab 2, Schedule 1
24	Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	**Yes**	Exhibit E, Tab 2, Schedule 1
EXHIBIT 6 - Operating Cost			
Overview			
Ch 2, p 25	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes, benchmarking, description of the continuous improvement or efficiency gains	**Yes**	Exhibit F, Tab 1, Schedule 1
Summary and Cost Driver Tables			
Ch 2, p 26	Summary of recoverable OM&A expenses	**Yes**	Exhibit F, Tab 1, Schedule 2 Appendix 2-JA
26	Recoverable OM&A cost drivers	**Yes**	Exhibit F, Tab 1, Schedule 2 Appendix 2-JB
26	Change in OM&A in test year attributable to a change in capitalized overhead	**Yes**	Exhibit F, Tab 2, Schedule 2
26	OM&A variance analysis for test year with respect to bridge and historical years	**Yes**	Exhibit F, Tab 1, Schedules 3 to 6
Program Delivery Costs with Variance Analysis			
Ch 2, p 26	O&M Costs for: - employee compensation - shared services - corporate cost allocation - purchase of non-affiliate services - one-time costs - OEB costs - Charitable and political donations	**Yes**	Exhibit F, Tab 1, Schedules 3 to 6
Employee Compensation			
Ch 2, p 26	Employee complement, compensation and benefits	**Yes**	Exhibit F, Tab 4, Schedule 1 Appendix 2-K
26 - 27	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes: - year over year variances - basis for performance pay, eligible employee groups, goals, measures and review process for pay-for-performance plans - benchmarking studies	**Yes**	Exhibit F, Tab 4, Schedule 1 Exhibit F, Tab 4, Schedule 1, Attachments 1 to 5
27	Employee benefit programs including pensions	**Yes**	Exhibit F, Tab 4, Schedule 1 Exhibit F, Tab 5, Schedule 1, Attachment 1
27	Most recent actuarial reports	**Yes**	Exhibit F, Tab 5, Schedule 1, Attachment 1

Shared Services and Corporate Cost Allocation			
Ch 2, p 27	Identification of shared services	**Yes**	Exhibit F, Tab 2, Schedule 1
27	Allocation methodology for corporate and shared services	**Yes**	Exhibit F, Tab 2, Schedule 1
28	Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section	**Yes**	Exhibit F, Tab 2, Schedule 1
28	Variance analysis - test year vs last OEB approved and most recent actual	**Yes**	Exhibit F, Tab 2, Schedules 1 to 5
28	Identification of any Board of Director costs for affiliates included in LDC costs	**Yes**	Exhibit F, Tab 2, Schedule 2
Purchase of Non-Affiliate Services			
28	Procurement Policy	**Yes**	Exhibit F, Tab 3, Schedules 1 to 4
28	Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product and describe how vendor was selected	**Yes**	Exhibit F, Tab 3, Schedule 4 (describes policy for single/sole sourced contracts)
One-time Costs			
28	One-time costs - historical, bridge, test year costs. Explanation of cost recovery in test years. Costs in the test years will not result in an over recovery in future years.	**N/A**	Exhibit F, Tab 8, Schedule 2
Regulatory Costs			
28	Regulatory costs - breakdown of actual and forecast costs Supporting information, legal fees, consultant fees, costs awards, etc.	**Yes**	Exhibit F, Tab 8, Schedule 1
Charitable and Political Donations			
29	File the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s).	**N/A**	Exhibit F, Tab 8, Schedule 3
29	Detailed information for all contributions that are claimed for recovery	**N/A**	Exhibit F, Tab 8, Schedule 3
29	Charitable Donations - confirmation that political contributions not included	**N/A**	Exhibit F, Tab 8, Schedule 3
Depreciation, Amortization and Depletion			
29	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Asset amount and rate of depreciation/amortization must tie back to the accumulated depreciation balances in the continuity schedule under rate base.	**Yes**	Exhibit F, Tab 6, Schedule 1
29	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	**Yes**	Exhibit F, Tab 6, Schedule 1 and Attachment 1
29	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	**Yes**	Exhibit F, Tab 6, Schedule 1
29	Depreciation/amortization policy Summary of changes to depreciation/amortization policy since last CoS	**Yes**	Exhibit F, Tab 1, Schedule 1, Attachment 1
29	Explanation of any deviations from depreciating components of PP&E separately	**N/A**	
Taxes or PILs and Property Taxes			
30	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years	**Yes**	Exhibit F, Tab 7, Schedule 1
30	Supporting schedules and calculations identifying reconciling items	**Yes**	Exhibit F, Tab 7, Schedule 2 Attachments 1 to 4
30	Most recent federal and provincial tax returns	**Yes**	Exhibit F, Tab 7, Schedule 3 and Attachments 1 and 1A
30	Financial Statements included with tax returns if different from those filed with application	**N/A**	
30	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	**Yes**	Exhibit F, Tab 7, Schedule 2 Attachments 5 to 6
30	Supporting schedules, calculations and explanations for other additions and deductions	**Yes**	Exhibit F, Tab 7, Schedule 1
Non-recoverable and Disallowed Expenses			

30	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	**Yes**	
Integrity Checks			
31	Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application	**Yes**	Exhibit F, Tab 7, Schedule 1
31	The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years	**No**	Exhibit F, Tab 7, Schedule 1
31	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st	**Yes**	Exhibit F, Tab 7, Schedule 1
31	The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed	**Yes**	Exhibit F, Tab 7, Schedule 1
31	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	**No**	Exhibit F, Tab 7, Schedule 1
31	CCA is maximized even if there are tax loss carry-forwards	**Yes**	Exhibit F, Tab 7, Schedule 1
31	A statement is included in the application as to when the losses, if any, will be fully utilized	**Yes**	Exhibit F, Tab 7, Schedule 1
31	Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to ne income for tax purposes, must agree with the OM&A analysis for compensation	**Yes**	Exhibit F, Tab 7, Schedule 1
31	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.	**Yes**	Exhibit F, Tab 7, Schedule 1
Z-Factor Claims		**Yes**	
31	Evidence that z-factor costs incurred meet eligibility criteria, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement	**N/A**	Exhibit F, Tab 8, Schedule 4
EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
33	OEB's cost of capital parameters used	**Yes**	Exhibit G, Tab 1, Schedule 1
33	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	**Yes**	Exhibit G, Tab 1, Schedule 1
33	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	**Yes**	Exhibit G, Tab 1, Schedule 4
33	Explanation for any changes in capital structure	**Yes**	Exhibit G, Tab 1, Schedule 1
Cost of Capital (Return on Equity and Cost of Debt)			
34	Calculation of cost for each capital component	**Yes**	Exhibit G, Tab 1, Schedule 1
34	Profit or loss on redemption of debt	**Yes**	Exhibit G, Tab 1, Schedule 1
34	Copies of promissory notes or other debt arrangements with affiliates	**Yes**	Exhibit G, Tab 1, Schedule 2
34	Explanation of debt rate for each existing debt instrument	**Yes**	Exhibit G, Tab 1, Schedule 2
34	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Exhibit G, Tab 1, Schedule 2
34	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	**Yes**	Exhibit G, Tab 1, Schedule 2
Not-for-Profit Corporations			
34	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	**N/A**	
EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS			
34	List of all outstanding DVA and sub-accounts; provide description of DVAs	**Yes**	Exhibit H, Tab 1, Schedule 1
34	Completed DVA continuity schedule for period following last disposition to present - live Excel format	**Yes**	Exhibit H, Tab 1, Schedule 5
34	Confirm use of interest rates established by the OEB by month or by quarter for each year	**Yes**	Exhibit H, Tab 1, Schedule 1
35	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	**Yes**	Exhibit H, Tab 1, Schedule 1
35	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	**Yes**	Exhibit I1, Tab 1, Schedule 3
35	Statement as to any new accounts, and justification.	**Yes**	Exhibit H, Tab 1, Schedule 1
35	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	**Yes**	Exhibit H, Tab 1, Schedule 1
Disposition of Deferral and Variance Accounts			
36	Identify accounts for which disposition is sought	**Yes**	Exhibit H, Tab 1, Schedule 1
36	Identify accounts for which disposition is not sought and the reasons	**Yes**	Exhibit H, Tab 1, Schedule 1
36	Propose the method to be used for recovery or refund of balances that are proposed for disposition	**Yes**	Exhibit H, Tab 1, Schedule 1

36	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	**Yes**	Exhibit A, Tab 6, Schedule 4 Exhibit H, Tab 1, Schedule 3
36	Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account	**N/A**	
36	Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference	**N/A**	
36	Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period	**Yes**	Exhibit H, Tab 1, Schedules 1 to 5
EXHIBIT 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants			
36	Identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection	**Yes**	Exhibit I1, Tab 1, Schedule 1
36	Steps taken to functionalize the assets in the functional categories	**Yes**	Exhibit I1, Tab 2, Schedule 1 Exhibit I1, Tab 3, Schedule 2
36	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	**Yes**	Exhibit I1, Tab 5, Schedule 1
36	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	**Yes**	Exhibit I1, Tab 4, Schedules 2 to 4
EXHIBIT 10 - Rate Design for Uniform Transmission Rates			
Bill Impact Information			
37	Provide bill impact of the application including the dollar and percentage impact on the average customer's total bill and the percentage impact on transmission rates	**Yes**	Exhibit I2, Tab 5, Schedule 1
37	Bill impacts for typical customers and consumption levels.	**Yes**	Exhibit I2, Tab 5, Schedule 1
Setting the Uniform Transmission Rates			
37	Overview of how the UTR are established in Ontario and how these rates are determined	**Yes**	Exhibit I2, Tab 1, Schedule 1
37	The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool	**Yes**	Exhibit I2, Tab 2, Schedule 1
37	Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	**Yes**	Exhibit I2, Tab 4, Schedule 1
37	A table explaining and documenting the determination of the UTR including: - previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool; - OEB file number of each decision approving each revenue requirement and charge determinant; - proposed revenue requirements and charge determinants as proposed in the application; - the calculation of the UTR for each pool; - the transmission revenue allocator for each of the Ontario transmitters in the pool; - an explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates	**Yes**	Exhibit I2, Tab 1, Schedule 1 Exhibit I2, Tab 6, Schedule 1, Attachment 1 Exhibit I2, Tab 6, Schedule 2, Attachment 1 Exhibit I2, Tab 6, Schedule 2, Attachment 2

SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

This schedule provides a summary of directives and undertakings from past Ontario Energy Board ("OEB") proceedings and provides a status update or explains the steps Hydro One has taken to address the OEB's direction as part of this Application.

1. EB-2016-0160 – 2016/2017 TRANSMISSION RATE APPLICATION

In its decision in EB-2016-0160 dated September 28, 2017 (the "Prior Decision"), the OEB made a number of findings and observations about Hydro One's processes and approach and how these might be improved. Hydro One has taken steps to address each of the findings raised by the OEB. The table below lists the OEB's direction, provides a summary of how the company has addressed the direction to-date and includes an evidentiary reference pointing to where further detail may be found.

OEB Decision EB-2016-0160 and Section Reference	Page	Hydro One Action Items	Evidentiary Reference
4.1 - Planning			
"Continue to make improvements to [Hydro One's] planning process addressing the issues that have been identified in this proceeding as well those identified in Hydro One's internal audit, and to report on the progress made in this area in its next transmission rates application."	p. 117 p. 18	Key issues identified in the hearing and in the internal audit included the pacing of capital expenditures, risk identification and mitigation, and timing of inputs into the plan, gaps in the asset condition assessment process as demonstrated by the urgent need to replace insulators, and the way the company prioritizes and optimizes capital investments during its investment planning process. To address these issues, Hydro One implemented an improved eight-step investment planning process as described in Transmission System Plan (TSP). Key improvements include: (i) consistent risk assessment scoring for safety, reliability and environmental risk mitigation based on new standardized frameworks that are comparable across different investment types; (ii) clearer definitions of risk impacts to permit consistent scoring across investment types, and calibration sessions to ensure standardized risk assessment scoring; and (iii) challenge sessions, which engage the relevant stakeholders across all levels of the organization, to review and discuss investment trade-offs. Steps taken to address the issues raised in the internal audit report are listed in a chart in TSP Section 2.1, Appendix 1, Table 2.	TSP 2.1 TSP 2.1, Appendix 1, Table 2

"Some of the elements that require more focus include … a consistent, comprehensive asset condition assessment process which directly links to the TSP and the capital investment plan..."	p. 18	Hydro One enhanced its evidence to better explain the asset condition assessment (ACA) process and highlight its role as a key driver in identifying the need and scope of investments underpinning Hydro One's capital investment plan. Hydro One also engaged Metsco to perform a third party review of its ACA process. The Metsco study concluded that Hydro One's ACA process is comparable to advanced asset management practises found elsewhere in the industry. The Metsco study also provided several detailed case studies which illustrated real examples of proposed capital investments that arise from Hydro One's ACA process, thus illustrating how the ACA links to Hydro One's capital investment plan.	TSP 2.1.2.6 TSP 3.2.5
"Some of the elements that require more focus include … appropriate pacing of capital expenditures that achieves a proper balance of need and rate impact..."	p. 18	Hydro One addressed OEB concerns about pacing through the following actions: • Overall spend: The envelope was set at a level tested with customers. Hydro One agreed with customer feedback that this approach offered the correct balance between ratepayer costs and risk mitigation. • Productivity: Hydro One's forecast program includes $704 million in forecast productivity savings over the planning period of the TSP. These savings represent a commitment to continuous improvement across the organization to deliver Hydro One's work program at a lower cost. • Prioritization: The clear risk prioritization permitted by the enhanced investment planning process ensures that the candidate investments mitigating the highest risk for the least cost should be performed first.	TSP 1.6.2 TSP 2.1.4 and 2.1.5 TSP 3.2 TSP 3.3.1.2

"Some of the elements that require more focus include … Hydro One's ability to execute the proposed capital program in a timely fashion."	p. 18	Hydro One took the following steps to improve its ability to deliver its capital program: (i) reviewed and streamlined its capital delivery process; (ii) created a Redirection Committee to appropriately redirect funds and resources to allow prudent and timely adjustments to be made to the work program; (iii) enhanced upfront engineering and planning deliverables; (iv) increased governance quickly identify when redirection of funds and resources are required; and (v) improved estimating and scheduling tools and processes. Over the past four years, Hydro One placed $3,396.0 million in-service with an overall variance of 5.0%. In 2017 after a number of process changes were implemented, Hydro One placed $872.2 million in-service with variance of 0.5% from OEB approved, demonstrating the company's improved ability to meet its target at a portfolio level.	TSP 2.1.9 Exhibit B, Tab 2, Schedule 1
"The OEB requires Hydro One to complete an independent third-party assessment of its TSP and to file this assessment with its next transmission rate application. This assessment should include Hydro One's asset condition assessment and capital investment planning processes."	p. 117 p. 18	Hydro One engaged Metsco Energy Solutions to review its asset condition assessment process and the Boston Consulting Group to review its capital investment planning process. Metsco Energy Solutions found that both the Asset Risk Assessment and Asset Analytics align with other the asset management frameworks found elsewhere in the industry, and are sufficiently rigorous and robust to accomplish their intended tasks from the analytical perspective, and Boston Consulting Group found that Hydro One has implemented a consistent and thorough capital investment planning process that meets or exceeds expectations for an above average utility planning process.	BCG Report at TSP 1.4, Attachment 14 Metsco Report at TSP 1.4, Attachment 13

4.2 - Customer Engagement and Reliability Risk Model			
"Begin the customer engagement process sufficiently in advance of filing the application, include LDCs (to determine practical ways to seek some input from their end users), incorporate timely and meaningful input from First Nations representatives, and ensure that information presented to customers is unambiguous and easy to understand." This directive is further delineated below.	p. 117 p. 24	Hydro One's customer engagement process is described in TSP 1.3. Customer feedback was considered in the investment planning process and proposed capital plan as described at TSP 2.1.2.8 and TSP 3.2.2 respectively.	TSP 1.3 Exhibit A, Tab 7, Schedule 2
Undertake a timely customer engagement process		Hydro One's 2017 Transmission Customer Engagement Survey was conducted between May and June 2017 prior to its planning process. The results of an interim report dated May 31, 2017 and a final report dated July 2, 2017 were used by planners developing the Transmission System Plan as described in TSP 3.2.2.	TSP 1.3, Appendix 1 TSP 3.2.1
Seek input from LDCs and their end-users		Hydro One's 2017 Transmission Customer Engagement Survey included a new dedicated section for LDCs to provide feedback on behalf of their respective customers. In addition, Hydro One's account executives interact with and engage LDCs in discussion regarding the needs of their ultimate end-use customers. Hydro One also contacted some LDCs to discuss how it could solicit feedback from LDC end-users in future.	TSP 1.3, Appendix 2 TSP 1.5.2

Seek Input from First Nations and Metis Nation groups		As part of its 2017 Transmission Customer Engagement Survey, Hydro One asked LDCs that serve First Nations and Métis communities what they felt Hydro One could do to better serve the specific needs of these communities. Hydro One also leveraged its ongoing engagement activities with First Nations and Métis communities to identify customer needs and preferences for these customers.	Exhibit A, Tab 7, Schedule 2 TSP 1.3, Appendix 2
Present information (including the reliability risk model) to customers in a clear, unambiguous manner		Hydro One engaged Innovative Research Group to help design its customer consultation survey. Overall, customer consultations were improved by: (i) providing customers with a broader spectrum of options and more detail about each option and investment outcome; (ii) leading language was eliminated; (iii) information about how and when the risk model is used was provided; (iv) including links in the survey to secondary documents with contextual information and definitions.	TSP 1.3, Appendix 2

4.3 - Capital Expenditures			
"*Provide a report detailing its overall performance in the execution of the capital program relative to plan showing the performance at the program level in terms of overall expenditures and in-service additions compared to the approved plan. In addition, for major projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years, the report should show the status of each project and an explanation of any variances regarding scope, cost or schedule.*"	p. 117 p. 30	Hydro One prepared a report including the following analysis: 1. Reductions to Proposed Capital Expenditures – a description of actions taken by Hydro One to allocate the capital reductions and an explanation of how the allocations meet the intent of the Decision 2. Impact on In-service Additions – a description of how and when capital reductions will impact in-service additions 3. Performance Reporting – a description of Hydro One's overall performance in the execution of its capital program relative to plan showing: (a) Performance at the sub-category level for capital expenditures and in-service additions; and (b) Performance at the projects and programs level for projects and programs with total budgeted cost greater than $3 million which are planned to be completed in 2017 and 2018, the status of each project and an explanation of any variances regarding scope, cost or schedule	Exhibit C, Tab 2, Schedule 1, Attachment 1
"*For the same reasons described in the previous section, the OEB does not have sufficient information to judge the adequacy of the proposed ISA reductions. The status report requested by the OEB in section 4.4 of its Decision already requires Hydro One to report on actual ISA compared to plan. In addition, the OEB directs Hydro One to specifically describe in that report how the actions taken by Hydro One to meet the intent of the Decision regarding capital reductions affected ISA. This information would enable future OEB panels to determine whether any of the proposed additions to rate*	DRO Decision p. 8		

base should be denied." [draft rate order decision issued November 9, 2017 at p. 8 ("DRO Decision")]			
4.5 - Line Losses			
"Hydro One should work jointly with the IESO to explore cost effective opportunities for line loss reduction. Hydro One should also explore, as part of its investment decision process, opportunities for economically reducing line losses."	p. 117 p. 33	Hydro One retained EPRI to review transmission line loss mitigation practices by other utilities and compare them to Hydro One's practices. The EPRI report concluded that Hydro One design practices are materially consistent with industry best practices for loss mitigation. A description of how line loss mitigation factors are considered in Hydro One's planning process is also provided.	TSP 1.8
4.6 - Benchmarking			
"*The OEB directs Hydro One to report on its implementation of the recommendations from the* [Navigant Total Cost] *benchmarking study* [submitted in EB-2016-0160] *in future proceedings*."	p. 117 p. 35	A status update on Hydro One's implementation of recommendations in the Navigant Total Cost Benchmarking study includes the following: (i) the company's evolved scorecard and new performance reporting governance framework; (ii) the company's progress on creating a pipeline of construction ready projects; (iii) the company's management of contingencies; and (iv) improvements to its project management process, among other things.	Exhibit A, Tab 2, Schedule 4, Attachment 1
"*Benchmarking studies should focus on comparing outcomes that are consistent with the RRF and which demonstrate continuous improvement*."	p. 117 p. 35	Benchmarking studies included in this application focus on comparing outcomes that are consistent with the RRF (e.g. operational effectiveness). Key areas of benchmarking include Hydro One's asset management processes and the pacing for replacing major asset classes. These studies concluded that Hydro One's practises are in-line with or better than its industry peers. Hydro One also commissioned econometric assessments of its costs relative to a peer group of US utilities. The cost assessments showed a history of excellent cost performance relative to the industry and indicated that performance would continue to improve during the test period.	TSP 1.4 and Attachments

5.0 - Productivity Improvements and Performance Scorecard			
"*Establish firm short and long term targets for productivity improvements and associated reduction in revenue requirements as a means to drive continuous improvement and improve its internal and external benchmarking standings.*"	p. 117	Hydro One identified savings opportunities and established targets in capital and OM&A of approximately $704M from 2020 to 2024. These savings have been directly embedded into the transmission system plan. Underlying the majority of these savings are specific productivity initiatives that have been identified, reviewed, approved and made subject to tracking and reporting requirements.	TSP 1.6
"*Put more emphasis on including performance metrics in the scorecard that provide objective year-over-year unit cost measures of productivity, safety, reliability and quality of service improvements.*"	p. 117	Hydro One continues to focus on opportunities to become more efficient in the deployment of capital and in managing the O&M budget. New unit cost measures include O&M expenditure per gross book value of in-service assets, line clearing cost per kilometer completed and brush control cost per hectare completed. These measures will be used to monitor the company's ability to become more efficient, emphasizing execution and cost performance and reflecting the outcomes of the overall business performance.	TSP 1.5.2, Table 6
"*Consider the merits of implementing measures that reflect outcomes of its overall business such as gross fixed assets/unit of load serving capacity to more fully illustrate its overall cost of service provision. Provide an analysis of the merits of this and similar measures with its next scorecard submission.*"	p. 117	Hydro One proposes a new *'TSP Implementation Progress'* measure, comparable to the '*Distribution System Plan Implementation Progress*' measure currently reported on Hydro One's Electricity Distributor Scorecard, to track actual in-service additions compared to budget, including any OEB variances. Hydro One also proposes to introduce the *'OM&A Program Accomplishment'* index and the '*Capital Accomplishment*' index.	TSP 1.5.2

"*The OEB expects Hydro One to propose an evolved scorecard in its next transmission rate application*."	p. 38	Hydro One's evolved scorecard includes improvements based on the company's past performance management measures, benchmarking studies, scorecards and measures of other utilities, as well as the OEB's guidance in the Handbook for Utility Rate Applications. Targets have been updated to reflect continuous improvement and the successful execution of programs and projects.	TSP 1.5.2
"*Hydro One should develop performance indicators that better reflect the satisfaction level of the ultimate end use consumer*."	pp. 38-39	A dedicated section was added to the engagement survey for LDCs to provide feedback on behalf of their respective customer bases. Subsequent to the issuance of the OEB's decision, Hydro One contacted some LDCs to solicit further approaches it could use to solicit feedback from LDC end-users, in the future. The feedback from LDCs included: (i) suggestions to continue using the account executive model to serve the needs of LDC customers, a program Hydro One has expanded as described above; (ii) that Hydro One meet with the large industrial customers of other LDCs, with Hydro One executives responding to customer concerns. Hydro One executed this suggestion and will facilitate future meetings as requested by LDCs; and (iii) that Hydro One may review LDC survey information. As indicated above, Hydro One considered the results of other LDCs customer surveys during its investment planning process	TSP 1.5.2
"*The OEB does not consider Hydro One's proposed inclusion of NERC and NPCC standards to be aligned with the intent of this element* [Policy Responsiveness] *of the OEB's scorecard objectives*."	pp. 39-40	Hydro One removed these measures from the evolved Transmission Scorecard.	TSP 1.5.2

"*Hydro One should consider expanding its policy response measures to include its initiatives related to the government's stated policy objectives on the development of a Smart Grid. The scorecard element of policy response should not be limited to purely quantitative measures. A qualitative assessment of Hydro One's response performance related to the policy objectives embedded in the government's smart grid initiatives is one example of the type of measure the OEB anticipates under this element of the scorecard*."	p. 40	For 2017 reporting and onwards, Hydro One introduced a measure designed to provide a qualitative assessment of the company's alignment with the policies set out in the 2017 Long-Term Energy Plan (the "LTEP"). Section 4 of the LTEP, "Improving Value and Performance for Consumers", describes the province's policies regarding the need for achieving continuous efficiencies and maintaining a culture of innovation in the energy sector. One component of achieving efficiencies is the right-sizing of end-of-life equipment. Hydro One proposes a new "End-of-Life Right-Sizing Assessment Expectation" measure to track the qualitative performance of the company in making right-sizing decisions for all identified end-of-life equipment or facilities. Hydro One will assess its performance by setting a target of a maximum of two (2) missed equipment right-sizing opportunities in annual regional planning assessments. The qualitative performance assessment is either "Met" or "Not Met" based on the quantitative maximum of two..	TSP 1.5.2
"*Hydro One should consider the merits of implementing measures that reflect outcomes of Hydro One's overall business such as gross fixed assets/unit of load serving capacity to more fully illustrate its overall cost of service provision. The OEB directs Hydro One to provide its analysis of the merits of this and similar measures with its next scorecard submission*."	p. 40	Hydro One reviewed this measure and concluded that it may not be an appropriate measure against which to assess outcomes or against which it can demonstrate continuous improvement.	TSP 1.5.2

6.1 - Rate Base			
"*Provide a detailed explanation in future applications of any material change in the lead-lag study results from previous similar studies*."	p. 117 p. 40	Hydro One provides a comparison of the prior study at Attachment 1 to Exhibit C, Tab 5, Schedule 1, which includes a summary of the changes and main drivers broken into revenue lag days, OM&A expenses lead days, interest expenses lead days, corporate income taxes lead days and removals and environmental remediation lead days.	Exhibit C, Tab 5, Schedule 1 and Attachment 1
7.2 - Compensation			
"*These 2016* [lump sum payment] *amounts should be included in the total costs for Hydro One employees that are used in the 2016 benchmarking studies*."	p. 50	Lump sum payments are included in the total costs in Exhibit F, Tab 4, Schedule 1 as well as the numbers presented in Attachment 2: Compensation Cost Benchmarking Study prepared by Mercer dated April 4, 2018.	Exhibit F, Tab 4, Schedule 1 and Attachment 2
"These [share grant] *amounts should be included in the total costs for Hydro One employees that are used in future benchmarking studies based on 2017 or 2018 costs*."	p. 50	Share grant awards are included in the total costs in Exhibit F, Tab 4, Schedule 1 as well as the numbers presented in Attachment 2: Compensation Cost Benchmarking Study prepared by Mercer dated April 4, 2018.	Exhibit F, Tab 4, Schedule 1 and Attachment 2
"*File complete total compensation information in the distribution rates proceeding as soon as possible incorporating items a) through g) listed in section 7.2.4 of this Decision*."	p. 118	Updated compensation tables and additional information are included in Exhibit F, Tab 4, Schedule 1, Attachment 5	Exhibit F, Tab 4, Schedule 1, Attachment 5
7.3 - OM&A (Excluding Compensation)			

"*Provide, in future applications, a high level description of the main contributors to any material variance between approved and actual total OM&A expenditures in previous applications and the impact of those variances on its longer-term ability to operate and maintain its assets*."	p. 63	A discussion of material variances in OM&A expenditures is included at Exhibit F, Tab 1, Schedules 1-2. Hydro One's ability to execute its OM&A plan is discussed in Exhibit F, Tab 1, Schedules 3-6, which contain information specific to Sustainment, Operations, Development and Common Corporate OM&A costs respectively, as well as a narrative (Schedule 7) describing how Hydro One will execute its OM&A work program.	Exhibit F, Tab 1, Schedules 1-2 Exhibit F, Tab 1, Schedules 3-7
9.0 - Load and Revenue Forecast			
"*Report in its next transmission rates case on how the NSC determinant might be modified to respond to the concerns raised by CME in its argument*."	p. 69	Hydro One performed an analysis to determine whether the network service charge determinant might be modified to respond to concerns raised by Canadian Manufacturers and Exporters. Based on the findings set out in Hydro One's report, the company is not proposing any change to the Network service charge determinant in this application. The results of the analysis show that changing the NSC determinant to address the concerns raised by CME would potentially result in material savings for only two industrial customers with small negative impacts on other customers. However, these two customers also appear to have modified their behaviour recently such that going forward they are no longer negatively impacted by the current NSC determinant. Hydro One is also in regular contact with its transmission customers and as part of its customer communications, Hydro One can raise customer awareness of the potential impact on their network charges if they shift their operations outside the 7 AM to 7 PM "peak period".	Exhibit I2, Tab 2, Schedule 1, Attachment 1

11.0 - Deferral and Variance Accounts			
Closure or Continuance of the LDC CDM and DR Variance Account for 2017 and 2018: "*The OEB realizes that the IESO will no longer be providing actual peak savings information in those years. However, this fact should not automatically lead to the closure of the variance account. The OEB directs Hydro One to use its best efforts to obtain from other sources the peak savings information that it needs to determine the variances to be recorded in this account.*"	p. 74	Hydro One proposes a methodology for calculating the variance account amounts and has included it in this application.	Exhibit H, Tab 1, Schedule 1
12.0 - First Nations Permits			
"*Continue to work diligently with affected First Nations to resolve outstanding permit issues in a timely manner with the objective of providing appropriate compensation while respecting First Nations rights.*"	p. 77	The Indigenous Relations department at Hydro One is leading the company's efforts to resolve permit issues related to Hydro One's assets on reserve and/or within traditional territories. As of February 2019, five of the previously outstanding agreements have been finalized and are with the federal government for final permit issuance, three of the previously outstanding agreements are in active negotiations and a newly expired agreement has entered into the negotiation phase.	Exhibit A, Tab 7, Schedule 2
14.0 - Accounting Issues			
"*If Hydro One proposes to continue using the cash method as the basis for recovering its pension costs beyond December 31, 2018, then, in its next transmission revenue requirement proceeding, Hydro One will provide evidence that addresses the principles,*	p. 81	Hydro One proposes to continue recovering its pension expense on a cash basis for the reasons set out in Exhibit F, Tab 5, Schedule 1. Hydro One believes this method is more beneficial to its customers than the accrual method because it results in lower costs recovered through rates. The cash basis is also more stable and predictable, allowing Hydro One to forecast the effect on rates for up to a three-year period.	Exhibit F, Tab 5, Schedule 1

practices, and policy determinations in accordance with the provisions of the Pension and OPEBs Report."			
16.0 - Export Transmission Service Rate			
"*The OEB is not inclined to change the Export Transmission Service Rate until such time as another cost allocation study demonstrates the rate to no longer be appropriate*."	p. 111	Hydro One updated the cost allocation model utilizing the latest available information. Using updated inputs, the ETS rate for 2019 is lower than the current rate. A decrease in the ETS rate will negatively impact the transmission rates that Ontario customers pay and could be perceived as benefiting customers in neighbouring jurisdictions at the expense of Ontario consumers. In addition, the current rate was negotiated as part of a settlement agreement and informed by OEB directed studies performed by the IESO and Hydro One. As such, Hydro One proposes to continue using the current ETS rate.	Exhibit I2, Tab 4, Schedule 1

2. NIAGARA REINFORCEMENT PROJECT (EB-2004-0476/EB-2006-0501)

The Niagara Reinforcement Project ("NRP") is not included in this Application. The NRP was approved under section 92 of the Ontario Energy Board Act, 1998 in July 2005 with an estimated in-service date of summer 2007. In 2006, when the project was near completion, an unforeseen land claim dispute put the project on hold, causing a section of the line near Caledonia to not be completed. A new agreement with First Nation partners was established in 2018, with the aim of in-servicing the line in 2019. Hydro One has submitted applications to the OEB to licence the new partnership and to transfer and sell NRP assets to that partnership. If the new partnership goes forward as planned, the NRP will not form part of Hydro One Transmission's revenue requirement, rate base or operating costs. As such, it is not included in this rate application. If there is a delay in finalizing the partnership agreements or setting up a new transmission company, Hydro

One will request OEB approval to track revenues in a deferral account to be disposed of in a future rates application.

ATTACHMENT 1 - TOTAL COST BENCHMARKING STUDY IMPLEMENTATION STATUS REPORT

In EB-2016-0160, Hydro One submitted an independent Transmission Total Cost Benchmarking Study ("TCB study") that compared Hydro One's performance against a group of peer utilities.[1] The TCB study concluded that in most areas Hydro One's transmission business benchmarked well relative to the peer group, but eight recommendations were made in areas where the company's performance was below median. The TCB study used 2014 cost and performance data for single-point-in-time comparisons, analysed trends in cost and performance from 2010 to 2014, and noted that trend analysis indicated Hydro One's performance had improved in some of the eight identified areas, particularly capital program management. A summary of the study recommendations is set out below.

Issue Area	Best-Practice Recommendation
Performance Metrics	Reassess and adjust performance indicators across all levels of the organisation
Substations Maintenance	Target a corrective maintenance spend that is ~25% of total corrective and preventative
Administrative Costs	Assess opportunities to reduce administrative costs
Capital Project Pipeline	Continue building on use of external resources for engineering to create a pipeline of construction-ready projects
Capital Program Expenditure Forecasts	Manage the contingency budgets at the portfolio / corporate level
Capital Program Management Resources	Allocate project management resources to improve effectiveness
Capital Program Budget	Formalise a rolling two-year capital budget and project portfolio and reporting framework, including projected earned value analysis
Driver Safety	Refresh formal driver training program

Figure 1: Summary of TCB Study Recommendations

[1] The TCB study was submitted as Exhibit B2, Tab2, Schedule 1, Attachment 1 in EB-2016-0160

In its decision in EB-2016-0160, the OEB ordered Hydro One to report on its implementation of the recommendations from the TCB study. This exhibit describes the steps Hydro One has taken to consider and implement the recommendations made in the TCB study.

1. PERFORMANCE TRACKING (METRICS)

The TCB study included a recommendation that Hydro One reassess its performance indicators with a view to reducing cost and improving performance. Specifically, the TCB study recommended that Hydro One: (i) establish corporate goals and objectives and identify existing and new metrics that support those goals and objectives; then (ii) implement a tracking and reporting framework and incorporate the metrics into the company's performance management process. Hydro One addressed this recommendation by developing an evolved scorecard, included in TSP Section 1.5, and a Performance Reporting Governance Framework, described in TSP Section 1.5.1.

Hydro One's evolved scorecard includes new and refined performance measures and associated corporate performance targets. Key Transmission measures were incorporated into the company's Team Scorecard to link the company's goals and objectives with performance-based compensation to incent continuous improvement.

Hydro One's new Performance Reporting Governance Framework provides a mechanism by which the company develops performance measures that align with the OEB's Renewed Regulatory Framework and the company's goals and objectives, as well as a process for Hydro One to track and report its performance for the purpose of incenting continuous improvement in the company.

2. CAPITAL PROJECT DELIVERY (PIPELINE)

The TCB study included a recommendation that Hydro One build on its use of external engineering resources to create a pipeline of construction-ready projects with a view to improving its schedule performance and implementing its full capital budget. Specifically, the TCB study recommended that Hydro One: (i) maintain a project backlog equal to 20% to 30% of annual capital spending; then (ii) formalise the engineering and design process to define key milestones, develop key performance indicators to measure the engineering and design process and use internal engineers as ‘owner engineers’. Hydro One addressed this recommendation by engaging three external engineering companies and refining its engineering and design process. Hydro One is developing a project backlog and transitioning its internal engineers into the role of owner engineers as its relationship with external engineering resources matures and is refined.

Following the TCB study, Hydro One retained three external engineering companies which now produce approximately 25% of the company’s engineering designs. In general, external engineering resources focus on detailed and production engineering design, giving Hydro One the ability to ramp work up or down as the work program fluctuates. This gives the company flexibility in the short run while it develops a pipeline process for construction-ready jobs. There will be an initial time lag between the planning and development of the pipeline of construction ready jobs and the execution thereof. As Hydro One’s external engineering resources are trained to become more familiar with the company’s approach and processes, internal engineers will transition from reviewing external work for quality control to reviewing work for quality assurance with a view to having them ultimately operate in the role of owner engineer.

Hydro One improved its engineering and design process as described in Exhibit B, Tab 2, Schedule 1 – Capital Work Execution Strategy – to include a staged capital delivery process,[2] greater project controls[3] and new tracking and reporting mechanisms.[4] In addition, the company has a tracking and reporting process for external engineering work.

3. EXPENDITURE FORECASTS (CONTINGENCIES, PROBABILITIES)

The TCB study included a recommendation that Hydro One manage contingencies at the portfolio level with a view to freeing funds for other priority investment opportunities. Specifically, the TCB study recommended that Hydro One: (i) eliminate contingencies in individual projects and allow some spending dead-band for project management; then (ii) develop probability weighted forecasts to inform decision-making on projects and portfolio choices. Hydro One addressed this recommendation by introducing a new risk-based method for calculating contingency amounts.

In the past, Hydro One operated with a 10% contingency. This has been replaced with a new risk management program[5] that attaches a dollar value to project risk using a probabilistic approach and includes it as a contingency amount in the estimated project cost. The new approach is applied to projects with a gross estimated cost of $10 million or more and improves contingency estimates and management.

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[2] This is described in section 4 of Exhibit B, Tab 2, Schedule 1 and is comprised of three key stages: (i) Planning; (ii) Project Definition, which includes Project Scoping and Project Planning; and (iii) Execution, which includes Project Execution and Project Close. The company is in the process of streamlining the stage gate process so that certain jobs may be accelerated to be construction ready sooner than expected

[3] This is described in section 5.2 of Exhibit B, Tab 2, Schedule 1 and includes: (i) project management improvements; and (ii) better project controls in the areas of estimation, scheduling, change management and risk definition

[4] These are described in section 5.3 of Exhibit B, Tab 2, Schedule 1 and include: (i) monthly reporting on project and program status and variances; (ii) portfolio management; (iii) redirection; and (iv) stage gate approvals

[5] The risk-based management program is described in TSP Section 2.1

The risk program described in TSP Section 2.1 involves a review of the project scope, execution plan and schedule as well as the identification and quantitative analysis of risk with a view to developing mitigation plans and contingency amounts. Since the contingency amount is tied to specific risks, project managers may assess the contingency throughout the project lifecycle and release contingency amounts if the associated risk does not materialize.

Hydro One manages contingency at a portfolio level by regularly reviewing the remaining contingency amount and adjusting it up or down as required.

4. SUBSTATIONS MAINTENANCE

The TCB study included a recommendation that Hydro One target a corrective maintenance spend equal to approximately 25% of total maintenance (corrective and preventive maintenance combined) with a view to lowering costs by increasing preventive maintenance. Specifically, the TCB study recommended that Hydro One: (i) investigate the drivers of the high percentage of corrective maintenance to see if steps could be taken to reduce corrective work by increasing preventive work; then (ii) implement a “worst performer” program for stations with the most corrective maintenance.

During the 2019 to 2022 period, Hydro One will continue to implement steps to reduce overall maintenance costs. Hydro One has two initiatives underway to improve overall maintenance cost efficiency. These include the company’s move to condition-based maintenance and its air blast circuit breaker replacement program. Air blast circuit breakers are the most unreliable and costly breakers to operate and maintain within Hydro One’s circuit breaker fleet. High pressure air systems which support air blast breakers are costly to maintain and need for them ceases upon replacement of the air blast breakers. Focusing on replacing air blast circuit breakers is akin to targeting worst performers.

Condition-based maintenance allows maintenance activities to be carried out when it is needed, on the right asset, at the right time. Transition from time-based to condition-based maintenance will improve the safety, reliability and cost efficiency of power equipment maintenance. Hydro One is implementing enabling technologies and trial installations to facilitate its transition to condition-based maintenance. The enabling technologies include advanced sensors, real time monitoring equipment, information technology and data management systems that collect asset condition data to support analytics used for condition-based maintenance.

Hydro One investigated the reasons for its high corrective spend ratio and found that its definitions of corrective and preventive maintenance differ from other utilities in the industry, and that this may have contributed to the conclusion in the TCB study that Hydro One’s corrective spend ratio was above median. Hydro One has three maintenance categories: preventive; planned corrective; and demand corrective, which are defined as follows:

- Preventive: time-based and condition-based maintenance activities that follow a defined work standard task list. Approximately 62% of Hydro One’s maintenance work is preventive.
- Planned corrective: maintenance to correct unacceptable asset deficiencies discovered during preventive maintenance work, which may be addressed along with preventive maintenance work or in the near future as planned work that does not require a forced outage. Approximately 18% of Hydro One’s maintenance work is planned corrective.
- Demand corrective: maintenance that must be completed imminently to address critical conditions discovered by chance or through failure but not during

preventive maintenance work. Approximately 20% of Hydro One's maintenance work is demand corrective.

The TCB study combined Hydro One's planned corrective maintenance and demand corrective maintenance into a single "corrective maintenance" category. The TCB study did not investigate the different definitions of corrective maintenance used by Hydro One and the peer group. Some other utilities classify corrective maintenance differently. By way of example, the Institute of Nuclear Power Operations ("INPO") uses the following maintenance definitions:

- preventive maintenance: This includes actions that detect, preclude, or mitigate degradation of functional structures, systems, and components (SSC) to sustain or extend its useful life by controlling degradation and failures to an acceptable level. There are three types of preventive maintenance: periodic, predictive, and planned.
- corrective maintenance: This represents a level of deficiency of a plant component that has failed or that is significantly deficient such that failure is imminent (within its operating cycle/preventive maintenance interval) and it no longer conforms to or cannot perform its design function.

Under this classification, a portion of Hydro One's planned corrective maintenance would fall under INPO's definitions of preventive maintenance**,** which would have the effect of lowering Hydro One's overall proportion of corrective maintenance.

5. ADMINISTRATIVE COSTS

The TCB study included a recommendation that Hydro One reduce administrative costs by identifying the drivers of administrative costs and implementing process improvements to streamline and minimise them. Administrative costs include Hydro

One's Common Corporate Costs. The historical and forecast common corporate costs are set out in Exhibit F, Tab 2, Schedule 2 along with trends and variance explanations. As an input to the 2019-2024 business plan, Hydro One leadership undertook a process to review corporate costs. The review resulted in a significant commitment by business units to reduce corporate costs across the organization, such that common corporate costs in 2019 and 2020 are lower than planned costs over the last four years.

6. PROJECT MANAGEMENT (RESOURCES AND PROCESS)

The TCB study included a recommendation that Hydro One allocate project management resources to improve effectiveness with a view to improving project cost and schedule performance. Specifically, the TCB study recommended that Hydro One: (i) review and adjust project management resources to provide support for large projects and use project managers only for large projects; then (ii) refine the project management process to define interrelationships and establish accountability on projects. Changes made in this regard are described in Exhibit B, Tab 2, Schedule 1 and are summarized below.

In April 2017, Hydro One aligned its project management accountabilities under one team. Project Delivery Managers (PMs) were identified as being accountable for a project at the beginning of the Project Scoping phase rather than previously at the Project Execution phase after the budget and schedule had already been defined. This approach reduces the number of handoffs in the project lifecycle, provides a consistent approach to execution planning and leads to earlier recognition of potential project issues and risks, all of which increase the likelihood of delivering projects within scope, cost and on schedule.

Hydro One has made considerable improvements to the processes and tool suite for the Project Controls office in the areas of risk management, estimating, scheduling and project change management, as described in section 5.2 of Exhibit B, Tab 2, Schedule 1.

Cost control was improved to allow project teams to more accurately track costs, forecast and communicate variances in resourcing and cash flow both during a project and at project close. Improvements include a new simplified and standardized work breakdown structure (WBS) on all new investments starting in Q4 2017. A cost controller role has been installed to build out SAP for cost control and reporting utilizing the new WBS. The project manager is now supported by cost controllers and cost reports are generated with the new WBS to assist with project forecasting and reporting variances.

7. PORTFOLIO MANAGEMENT (CAPITAL BUDGET AND PORTFOLIO)

The TCB study included a recommendation that Hydro One formalize a rolling two-year capital budget and project portfolio and reporting framework including a projected earned value analysis with a view to making it easier to reschedule projects within a two year window and achieve planned annual investments. Specifically, the TCB study recommended that Hydro One: (i) develop parameters and business rules for a two-year rolling authorisation process; then (ii) reinstitute its earned value analysis to measure project progress, establish performance metrics that use the forecasted monthly cash flow and earned value analysis.

Hydro One recently formed a Redirection Committee, as described at TSP Section 2.1.9.3, to appropriately redirect funds or authorize additional spending as necessary. Through this process, Hydro One is tracking the impact of in-year changes, which gives the company greater line of sight into future year performance.

Hydro One also reviews its project and program status on a regular basis, as described in section 5.3 of Exhibit B, Tab 2, Schedule 1, which allows it to respond to current and potential future issues within the portfolio.

8. SAFETY (DRIVER)

The TCB study recommended that Hydro One establish a target for preventable motor vehicle collisions. A target of 1.6 preventable motor vehicle collisions per 200,000 hours worked was implemented for 2017. At year-end 2017, Hydro One achieved the target and additionally achieved a 10% reduction in preventable motor vehicle collisions since the TCB study was completed. In 2018, the rate of 1.6 was maintained. Hydro One is targeting a rate of 1.5 for 2019.

Hydro One implemented various improvements to its Driver Safety Program since 2016 such as reinforcing of Hydro One Safety rules governing driving, vehicle collision avoidance, policies, and *Highway Traffic Act* regulations governing vehicle drivers. Driver responsibilities and the role of the supervisor were clarified. The program includes 3 hours of supervisor-led defensive driver training. The Motor Vehicle Operator Training program targets high mileage drivers with four hours of in-class and one on one in-cab assessments (345 employees were trained in the program in 2017 and 196 employees were trained in 2018).

The strategy over the test period will be to continue to set targets annually as Hydro One strives for best in class performance. Hydro One will continue to review driver training requirements within the organization annually to ensure their currency and application.

EXECUTIVE SUMMARY

This Exhibit describes the scope and key aspects of Hydro One's application ("the Application"), including its proposed Custom Incentive Rate-Setting ("Custom IR") approach to establishing transmission rates for the period 2020 to 2022 (the "test period"). A Blue Page update will be filed by the end of Q2 2019 to include final audited balances for 2018.

A significant portion of Hydro One's assets are reaching the end of their useful life and have deteriorated to the point where investment is required to maintain customer reliability and meet safety and environmental sustainability requirements. A safe and reliable transmission system is essential to supporting strong and successful communities and essential to supporting business development and growth that provides job opportunities and drives Ontario's economy.

Hydro One is also sensitive to the rate impact of its plan on both its transmission customers and distribution-connected customers. In 2020, a typical Hydro One medium density (R1) residential customer consuming 750 kWh/month will see an increase of $0.77/month or 0.6% on their total bill as a result of the Application. Almost half of this increase is attributable to load decline due to government conservation initiatives and lower consumption. While some of the drivers of the bill impact, such as a decline in load, are out of Hydro One's control, Hydro One has made efforts to manage its costs while meeting its asset needs. In its plan, Hydro One has identified $370 million in productivity savings over the period of the Application. Hydro One has reduced its 2020 OM&A expenses by 9% over 2018 OEB approved levels of spending which will be achieved through sustained productivity gains, and revisions to its maintenance programs. Hydro One's plan appropriately balances the needs of the system, the assets and the customer preferences regarding outcomes and rates.

Hydro One Transmission's customer base is made up of: (1) electricity generators who deliver power to the transmission system, (2) distributors who deliver power to direct customers, and (3) end-users such as mining and industrial enterprises that use the power themselves at transmission level voltage. Hydro One's transmission customers have told Hydro One that safety and reliability are the outcomes that they care most about. Over the Application period Hydro One will invest nearly $3.9 billion in its assets to keep its transmission system safe and reliable. Hydro One has implemented improvements to its planning process to ensure that its spending is targeting to the assets that are the most critical and where the funding will have the greatest impact. Hydro One's plan will address critical safety and environmental risks in its system. It will improve reliability performance by 13% to return to the top quartile performance that Hydro One's transmission customers are expecting. In addition, Hydro One will spend $552 million to add capacity to the system to accommodate new customers and businesses, enabling economic growth in Ontario in communities such as Leamington and delivering on the requirements of Regional Planning processes and the government's Long Term Energy Plan.

1. SCOPE OF THE APPLICATION

On March 16, 2018 the Ontario Energy Board ("OEB") issued a letter setting out its expectations regarding future distribution rate and transmission revenue requirement applications by Hydro One. The letter directed Hydro One to file a transmission revenue requirement application for a four-year test period from 2019 to 2022. On April 4, 2018 Hydro One filed a letter with the OEB indicating that it was considering the potential impact of the OEB's new expectation on Hydro One's then upcoming application, which Hydro One had expected to be a Custom IR application with a 5 year test period.

Subsequently, Hydro One experienced organizational changes in July and August, 2018, which included the appointment of a new Board of Directors. As a result, Hydro One took the opportunity to brief the new Board of Directors and re-evaluate its transmission business plan to balance the needs of customers, system reliability and overall stewardship of its assets with a particular focus on increasing productivity and minimizing rate increases.

To permit this review to occur and adhere to the OEB's objective of a combined transmission and distribution application in the future, Hydro One adopted a two-step approach. First, Hydro One filed an application for a one-year mechanistic adjustment to Hydro One's 2019 revenue requirement (EB-2018-0130). Second, Hydro One filed this 3-year Custom IR application with a 2020-2022 test period to allow alignment with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement for a test period commencing in 2023.

Consistent with Chapter 2 of the OEB's *Filing Requirements for Electricity Transmission Applications* ("the Filing Requirements"), Hydro One's Transmission System Plan ("TSP") has provided a summary of capital expenditures for five future years, 2020-2024, which is referred to throughout the application as the "planning period" or "TSP planning period". However, this Application seeks approval for a revenue requirement only in respect of the 3-year test period of 2020-2022.

This Executive Summary provides an overview of Hydro One's transmission business and explains how Hydro One developed the Transmission Business Plan that underpins this Application, particularly with respect to its consideration for:

- asset related needs of the system arising from condition, performance, age, environmental and regulatory compliance requirements;

- identified customer needs and preferences for new transmission facilities, connections, services and reliability performance;
- customer rate impacts;
- feedback from the OEB's decision in Hydro One's 2017 and 2018 transmission rate proceeding (EB-2016-0160); and
- the OEB's expectations under the Renewed Regulatory Framework ("RRF") as outlined in the October 18, 2012 Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*, and further described in the OEB's October 13, 2016 *Handbook for Utility Rate Applications*.

In the Application, Hydro One is requesting the OEB's approval for:

- A transmission revenue requirement of $1,673.4 million for 2020, the underlying calculation of which is outlined in Section of 6.1 of this Exhibit;
- The charge determinants and allocation of the rates revenue requirement, by rate pool, to assist the OEB in developing Uniform Transmission Rates over the test period;
- The proposed Custom IR mechanism to be used for the determination of the revenue requirement for 2021 and 2022, as summarized in Section 4 of this Exhibit and detailed in Exhibit A, Tab 4, Schedule 1 of the Application;
- The evolved transmission performance scorecard proposed in this Application (Section 1.5 of Exhibit B, Tab 1, Schedule 1);
- The continuation or creation of the various regulatory deferral and variance accounts discussed in Section 6.10 of this Exhibit;

- The disposition of regulatory accounts with total net debit balances of $14.5 million effective January 1, 2020, to be recovered over a three-year period (Exhibit H, Tab 1, Schedule 3).

The proposed 2020 revenue requirement reflects a year-over-year increase of 4.7% versus the 2019 revenue requirement proposed in Hydro One's 2019 Transmission Application (EB-2018-0130), which is currently before the OEB. The average year-over-year increase in the revenue requirement over the 3 year test period is expected to be 4.9% per year.

The estimated total bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) is an increase of 0.6% ($0.77/month) in 2020. The estimated total bill impact for a typical Hydro One general service energy less than 50 kW customer (2,000 kWh/month) is an increase of 0.5% ($1.83/month) in 2020. The estimated total bill impact of this Application for a typical transmission-connected customer is an increase of 0.6% in 2020, assuming that transmission costs represent 7.4% of the average transmission-connected customer's total bill.

The 2020 total bill impacts are predominantly driven by a reduction to the load forecast underpinning rates driven by a government conservation policy change, detailed in section 6.3 of this Exhibit, and increases to rate base from capital projects placed in service that were largely completed prior to the test period of the Application. The proposed reduction to Hydro One's OM&A budget serves to mitigate these increases. Further details are provided in Section 6.11 of this Exhibit.

2. HYDRO ONE'S CONTINUED EVOLUTION

In late May 2016, Hydro One filed its transmission rate application for 2017 and 2018 rates (EB-2016-0160) ("the Prior Proceeding"). The Prior Proceeding was Hydro One's first major filing following the transition from a solely government-owned company, to a publicly-traded company. It was also Hydro One's first transmission revenue requirement application under the OEB's RRF. In the Prior Proceeding, Hydro One outlined the initial steps its new leadership had taken towards Hydro One's aspirations of becoming a best-in-class, customer-centric, commercial entity.

Since the Prior Proceeding, Hydro One has continued to increase its focus on customers, establish greater corporate accountability for performance and drive continuous company-wide improvements in efficiency and productivity. This has resulted in an overall customer satisfaction score of 90% for 2018 – the company's highest score ever and a 12% increase over 2016. This Application reflects Hydro One's continued efforts to enhance the customer-centric, commercial orientation of the organization and further align itself with the focus on outcomes that is articulated in the RRF.

Examples of this include:

- Hydro One's evolved regulatory transmission scorecard, as outlined in Section 1.5 of the TSP, containing new and revised metrics that incorporate the OEB's feedback in the decision from the Prior Proceeding. In addition, Hydro One developed and implemented a governance framework for the internal monitoring and reporting of performance measures within Hydro One.
- The implementation of a robust process for defining and measuring productivity savings, as outlined in Section 1.6 of the TSP, along with a commitment from Hydro One to deliver on $704 million in productivity savings over the 5-year

planning term of the TSP, of which $370 million will be achieved over the 3-year test period. Hydro One achieved $89 million in savings in 2016 through 2018[1].

- The implementation of improvements to Hydro One's investment planning process, including use of a revised risk assessment framework to ensure appropriate prioritization and optimization based on business and RRF outcomes that are informed by Hydro One's customer engagement process. Hydro One also increased the levels of enterprise engagement to ensure Hydro One's ability to execute the plan.
- An evolved customer engagement process that sought feedback on both the appropriate level and mix of investments through a determination of the outcomes that customers value most.

3. OVERVIEW OF THE TRANSMISSION BUSINESS

Hydro One's transmission assets form the backbone of Ontario's electricity system. The system serves approximately 98% of the Province by capacity and covers some of the most challenging and diverse geographies in Canada. The company's transmission system is comprised of approximately 290 transmission stations and approximately 29,000 circuit kilometers of high-voltage lines and towers operating at 500 kV, 230 kV or 115 kV. It represents approximately $13 billion in transmission assets. Hydro One's system transmits electricity from generation sources to load customers, including 42 transmission-connected local distribution companies (LDCs), Hydro One's own distribution system, and 84 large industrial customers directly connected to the transmission system. It is linked to five jurisdictions adjacent to Ontario through 26 high-voltage interconnections. A discussion of the unique considerations and constraints

[1] 2018 achieved productivity savings are based on Q3 forecast.

on Hydro One's transmission business can be found in Section 1.1 of the TSP (Exhibit B, Tab 1, Schedule 1).

4. CUSTOM IR PROPOSAL

This Application is based on a Custom IR approach for a 3-year period. Hydro One's revenue requirement for the first year of the 3-year period (2020) is to be determined using a cost of service, forward test year approach. To establish the annual revenue requirements for 2021 and 2022, Hydro One is proposing a Custom Revenue Cap IR in which the revenue requirement for the test year t+1 is equal to the revenue requirement in year t inflated by the Revenue Cap Index ("RCI").

The Custom Revenue Cap Index (RCI) is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index;
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor; and
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Transmission System Plan, beyond the amount of revenue recovered through the I – X adjustment.

A detailed discussion of these components along with the benchmarking used to inform the RCI is found in Exhibit A, Tab 4, Schedule 1. A summary of the RCI components is provided in the Table 1 below. The productivity factor of 0% is based on the recommendations of the Total Cost Benchmarking and Total Factor Productivity analyses completed by Power Systems Engineering Inc. ("PSE"). The results of PSE's analysis are provided in Attachment 1 of Exhibit A, Tab 4, Schedule 1.

Table 1: Revenue Cap Index Components

Custom Revenue Cap Index by Component	2021	2022
Inflation Factor (I)	1.40	1.40
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	3.64	3.37
Custom Revenue Cap Index Total	5.04	4.77

Note: Inflation Factor to be updated annually. Exhibit Reference: A-4-1, Table 3.

To align Hydro One's business interests with those of its customers and provide an additional element of protection for customers, Hydro One is also proposing the following features:

- An earnings sharing mechanism ("ESM") that will permit customers to share 50% of earnings that exceed the regulatory ROE by more than 100 basis points in any year of the Custom IR term;
- A capital in-service variance account ("CISVA") to track the cumulative difference over the Custom IR term of any under spending between: (a) the revenue requirement associated with actual in-service capital additions during a rate year; and (b) the revenue requirement associated with the OEB-approved forecast for in-service capital additions for that year, for any capital in-service additions that are 98% or lower than the OEB- approved level; and
- Z-factor and off-ramp mechanisms that apply OEB-approved criteria.

Hydro One's proposed Custom IR components, therefore, contain both OEB-approved components and other mechanisms that are designed to align the utility's needs with the interests of its customers.

5. HYDRO ONE'S TRANSMISSION BUSINESS PLAN

Hydro One's 2019-2024 Transmission Business Plan on which this Application is based will deliver the following outcomes:

- Optimizing the cost and performance of the existing assets through maintenance and renewal projects;
- Improving system and customer reliability to restore top quartile reliability performance as compared to the company's Canadian peers. In 2018, Hydro One's transmission reliability performance decreased from top quartile to 2nd quartile due to major storms and increased equipment-caused interruptions;
- Addressing customer needs and preferences through new customer connections, and regional development to enable growth and through system renewal to meet current requirements;
- Responding to customer power quality concerns by proactively monitoring power quality across the province and working with customers to resolve specific issues; and
- Incorporating productivity savings totalling approximately $370 million over the test period to offset the customer rate impacts of the proposed Business Plan.

Based on Hydro One's assessment of its transmission system, a significant portion of the assets are reaching the end of their useful life and have deteriorated to the point where investment is required to maintain customer reliability and meet safety and environmental sustainability requirements. A safe and reliable transmission system is essential to supporting strong and successful communities and essential to supporting business development and growth that provide job opportunities and drive Ontario's economy.

Hydro One is sensitive to the rate impacts of the investment plan on transmission customers as well as distribution connected customers and has taken steps to ensure that its approach to investment is aligned with principles of the RRF by:

- Ensuring that the Transmission System Plan ("TSP") reflects the consideration of customer needs and preferences identified in the customer engagement survey and is consistent with the feedback obtained from various other customer consultations undertaken by the company including consultations with distribution customers;
- Optimizing asset lifecycle investments required to optimize costs and operational risks to achieve business outcomes including identifying specific opportunities where Hydro One can extend the useful life of its assets and mitigate higher capital spending requirements for asset replacements in the future;
- Working with customers, distributors and key stakeholders to ensure regional infrastructure issues are integrated;
- Actively driving cost reductions and improved productivity savings to help offset customer rate impacts of the proposed investment plan; and
- Implementing an improved performance management system to provide greater accountability for performance outcomes.

Since the Prior Proceeding, Hydro One revised and implemented an improved eight-step risk-based investment planning process. Key improvements to the investment planning process include the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and
- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

The improved eight-step risk-based investment planning process is summarized in Section 6.4.2 of this Exhibit and described in greater detail in Section 2.1 of the TSP.

The development of the Transmission Business Plan was informed by three key inputs:

1. Hydro One's strategic priorities and the OEB's expectations under the RRF;
2. Input Hydro One has received from its customers; and
3. Benchmarking studies and other analyses outlined in Section 5.3 of this Exhibit and detailed in Section 1.4 of the TSP.

These inputs provided key insights which helped shape Hydro One's 2019-2024 Transmission Business Plan. The sections that follow describe how each of these factors impacted the Transmission Business Plan, summarize how the benchmarking studies included in the Application support the investments contained within and the process used to develop the Business Plan, as well as highlighting Hydro One's commitment to continuous improvement through the productivity savings that are built into the Transmission Business Plan.

A full copy of Hydro One's 2019-2024 Transmission Business Plan is provided as Attachment 1 to this Exhibit.

5.1 BUSINESS OBJECTIVES AND BUSINESS PLAN OUTCOMES

Hydro One’s strategic priorities provided guidance and informed the objectives that were used to develop the Transmission Business Plan. These strategic priorities are presented in Figure 1 below.

Strategic Priorities

- **Employees**
  - Maintain a safe and inclusive workplace for all employees
  - Foster a high level of employee engagement throughout Hydro One through a new engagement approach focused on developing company –wide action plans (“Time for Action”)
- **Customer Experience**
  - Deliver industry-leading customer service, in response to identified customer preferences
  - Foster innovation in the business to adapt to changing customer requirements and market opportunities
  - Advance reconciliation and work proactively to build relationships with Indigenous peoples and communities based on understanding, respect and mutual trust
- **Operational Effectiveness**
  - Invest in grid infrastructure and grid modernization to deliver a high level of reliability and quality to our customers
  - Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs
- **Government and Regulatory Relationships**
  - Maintain and build constructive, transparent relationships with governments and regulatory entities in all jurisdictions where we operate
  - Deliver on obligations mandated by government through legislation and regulatory requirements
- **Financial Strength**
  - Maintain a strong balance sheet to support continuing investment in our business
  - Invest in assets to better serve customers

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

Figure 1: Hydro One’s Strategic Priorities

The close alignment between the RRF outcomes and the outcomes that Hydro One seeks to achieve is demonstrated in the company's transmission business values and objectives, which are summarized in Figure 2, below.

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	• Provide 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 •

Figure 2: Transmission Business Values and Objectives

Exhibit Reference: B-1-1, Section 1.1, Figure 7.

Along with the strategic priorities noted above, Hydro One relied upon the findings from its 2017 Customer Engagement Survey and its ongoing interactions with its customers to inform its understanding of customer needs and preferences and inform assumptions regarding the appropriate funding envelope.

Figure 3, below, summarizes how Hydro One's Investment Plan aligns with the company's strategic priorities and business objectives and summarizes the planned investments that deliver on those objectives through the planning term.

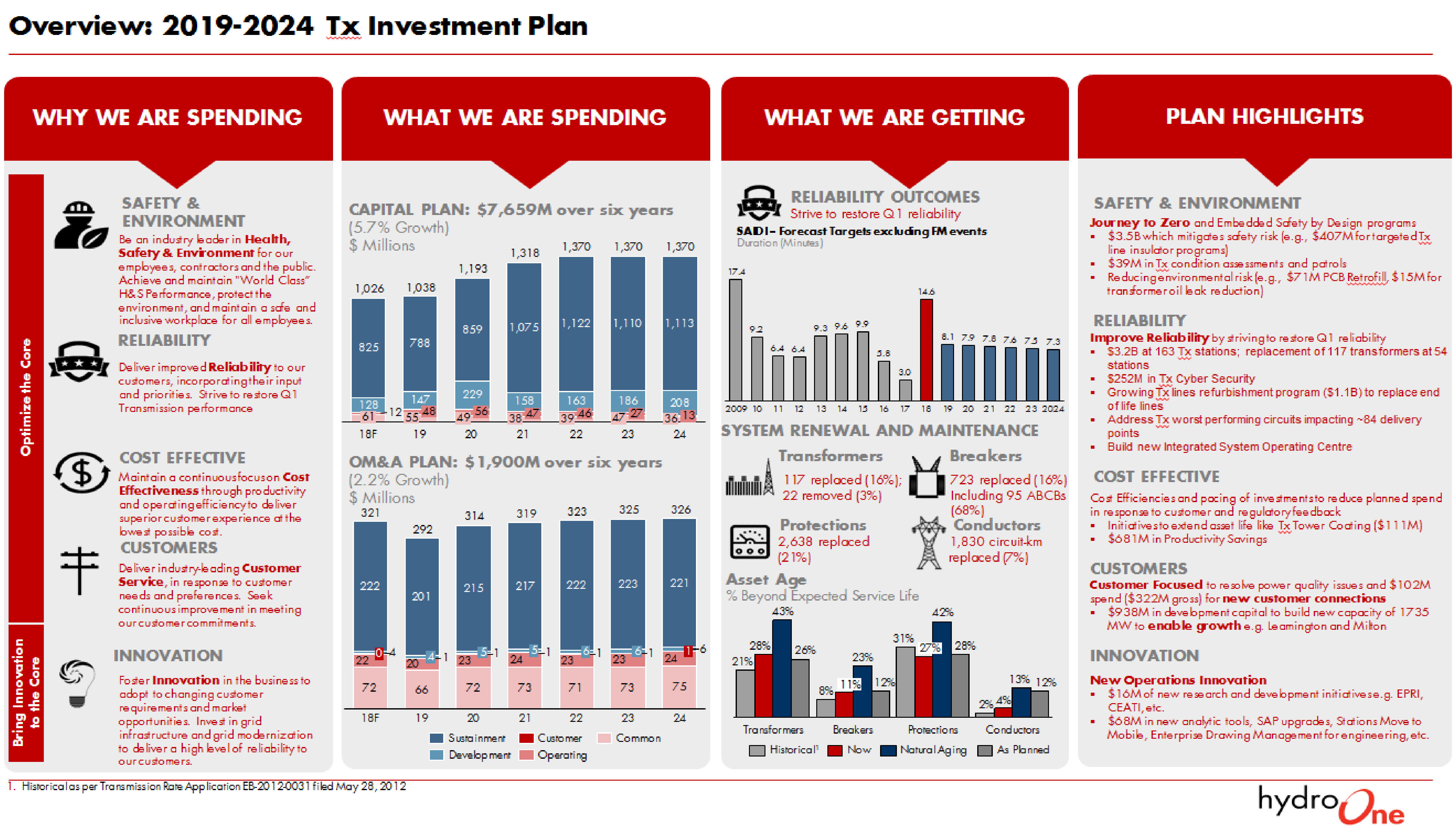

Figure 3: Alignment Between Strategic Objectives and Planned Investments

Exhibit Reference: B-1-1, Section 1.1, Figure 6

5.2 CUSTOMER ENGAGEMENT

Through its broad range of customer engagement activities, Hydro One has developed a clear understanding of the needs and preferences of its customers. In 2017, Hydro One undertook a formal customer engagement survey to obtain feedback on the needs and preferences of its customers to inform the development of its Transmission System Plan. This formal customer engagement exercise was the second such exercise undertaken by Hydro One for its transmission business.[2] The 2017 engagement survey implemented enhancements in consideration of the feedback that was received from OEB staff and intervenors on Hydro One's first customer engagement exercise through the course of the Prior Proceeding and through the Stakeholder Session held in March 2017.

Hydro One's 2017 Transmission Customer Engagement Survey sought customer feedback to inform both the level and mix of investments in its Business Plan. Among other things, the survey asked probative questions seeking to identify the outcomes that customers valued most and asked customers to consider trade-offs between reliability and cost through the use of illustrative scenarios.

The key messages received by Hydro One from the 2017 Transmission Customer Engagement Survey, in respect of the needs and preferences of its transmission customers, were as follows:

- Safety, reliability and outage restoration are customers' top prioritized outcomes;

[2] Hydro One's first customer engagement exercise for its transmission customers was undertaken in preparation for the Prior Proceeding.

- All customer segments prefer to see investments spread out over time versus investing now with higher rates in the short term and lower future increases or delaying investments with lower rates in the short term and higher future rates;
- Reducing the frequency of outages is more important than reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions;
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the Prior Proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option; and
- About half of end-user participants (19 of 38) rate power quality as an "extremely important" outcome.

The feedback provided through the customer engagement process informed the enhancements made to the improved investment planning process as follows:

- The revised risk assessment process focuses on assessing operational risks related to safety, reliability and environment**.** These outcomes are among the top customer priorities identified and validated through Hydro One's customer engagement. As such, the risk assessments that evaluate candidate investments for inclusion within the investment plan will reflect customers' top priorities in the assessment and prioritization of work.
- The probability factor as part of the risk assessment framework was also revised to incorporate outage frequency to reflect customers' preference and level of importance attributed to reducing the frequency of outages.

In addition to its customer engagement survey, Hydro One engages with its customers on an ongoing basis through its dedicated account executives who act as a "single point of contact" for transmission customers, large customer conferences, focused planning meetings with customers and various oversight committees and working groups. The feedback from these ongoing efforts aligns with the outcomes articulated in Hydro One's 2017 Customer Engagement Survey.

Further details regarding Hydro One's 2017 Transmission Customer Engagement Survey as well as Hydro One's ongoing customer engagement initiatives are provided in Section 1.3 of the TSP. A detailed discussion regarding how identified customer needs and preferences are reflected in the Transmission Business Plan can be found in Section 3.2 of the TSP.

Hydro One serves eighty eight First Nation communities representing close to 22,000 distribution system customers. Hydro One has developed an Indigenous Relations Strategy that focuses on investing in the development and maintenance of Hydro One's relationship with the Indigenous communities it serves which allows Hydro One to execute its work program, establish and renew permits on First Nation lands and ensure its transmission assets on reserve are properly maintained. Hydro One aims to become the primary business partner to Indigenous communities by 2021.

Further details of Hydro One's ongoing engagement with First Nations communities, the issues identified and actions Hydro One is taking to address them can be found in Exhibit A, Tab 7, Schedule 2.

5.3 BENCHMARKING

In support of the Application, Hydro One engaged independent experts to undertake 17 benchmarking studies and asset condition analyses. The resulting reports are included in this Application and are discussed in Section 1.4 of the TSP, in Exhibit A, Tab 4, Schedule 1, and in Exhibit F, Tab 4, Schedule 1. The findings from these studies were used by Hydro One to inform or assess: (i) the pacing of investments, and the condition of Hydro One's key transmission assets, (ii) the quality of Hydro One's investment planning and asset condition assessment processes, as ordered by the OEB in the Prior Proceeding, (iii) total compensation costs, and (iv) total factor productivity and total cost performance.

In the Prior Proceeding, the OEB expressed concerns with Hydro One's planning process and ordered Hydro One to seek an independent expert review of its investment planning and asset condition assessment processes. Hydro One engaged the Boston Consulting Group (BCG) to review its improved investment planning process and Metsco Energy Solutions Inc. to review its asset condition assessment process. The reports resulting from these reviews are discussed and provided as Attachments to Section 1.4 of the TSP. The review of Hydro One's investment planning process by BCG concluded that Hydro One had implemented a consistent and thorough planning process that meets or exceeds expectations for a typical utility planning process in all areas. The review of Hydro One's asset condition assessment process concluded that Hydro One's asset management process was comparable to other frameworks found elsewhere in the industry and is sufficiently rigorous and robust.

Hydro One's proposed RCI is informed by an independent expert assessment of total factor productivity ("TFP") and a total cost benchmarking study, each of which were performed by Power Systems Engineering ("PSE"). PSE analyzed the TFP of the transmission industry, as well as Hydro One’s TFP performance relative to itself. PSE determined that Hydro One’s TFP has consistently been greater than that of the transmission industry as a whole. This was further confirmed by PSE’s findings from the total cost benchmarking study, which showed that Hydro One’s actual costs are well below benchmarked costs. The results of PSE’s analysis are provided in Attachment 1 of Exhibit A, Tab 4, Schedule 1.

5.4 PRODUCTIVITY SAVINGS

To further its commitment to delivering outcomes that are valued by its customers, Hydro One has developed a comprehensive and rigorous process for identifying, developing, implementing, monitoring and measuring productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs. Within this framework, quantifiable productivity improvements are included in the Business Plan and corporate scorecards with clear accountabilities for delivering the anticipated savings. The framework is outlined in detail in Section 1.6 of the TSP.

Hydro One has identified expected productivity savings in Capital and OM&A totaling approximately $704M over the TSP planning period, approximately $370M of which is expected during the test period. These savings have been directly embedded into the cost forecasts underpinning the Business Plan and the TSP. A summary of Hydro One’s forecast productivity savings for the 2020-2024 planning period is provided in Table 2.

Table 2: Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Operations Progressive (Defined)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Operations Progressive (Undefined)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive (Defined)	6	12	12	10	10	49
Progressive (Undefined)	11	27	49	68	81	237
Progressive Placeholder	17	39	61	78	91	286

Exhibit Reference: B-1-1, Section 1.6

The Operations, Information Technology and Corporate savings above reflect the expected quantifiable productivity savings for initiatives that have been identified by each group and verified through Hydro One's productivity governance framework. In addition, the Operations group has committed to identifying additional productivity savings over the planning period in the form of Progressive Productivity. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB's decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes.

Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:

1. $49 million in Progressive (Defined) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and
2. $237 million in Progressive (Undefined) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

Hydro One’s commitment to these savings in this Application is to the benefit of ratepayers because the capital expenses underpinning the proposed revenue requirements are reduced by these amounts. Over the Planning Period, any proposed Progressive Productivity measures will be reviewed against the governance framework and, if approved, will be credited against the savings target.

6. KEY ELEMENTS OF THE APPLICATION

6.1 REVENUE REQUIREMENT

Hydro One’s 2020 transmission revenue requirement is shown in Table 3. The revenue requirement in subsequent years of the test period will be determined using the RCI, which is described in Section 4 of this Exhibit and detailed in Exhibit A, Tab 4, Schedule 1.

Table 3: Revenue Requirement ($ Millions)

Components	2018[1]	2019[2]	2020	Reference
OM&A	394.3	-	375.9	Exhibit F, Tab 1, Schedule1
Depreciation and Amortization	468.6	-	471.5	Exhibit F, Tab 6, Schedule 1
Income Taxes	57.2	-	52.7	Exhibit F, Tab 7, Schedule 2, Attachment 1
Return on Capital	703.6	-	773.2	Exhibit G, Tab 1, Schedule 1
Total Revenue Requirement	**1,623.8**	**1,642.3**	**1,673.4**	
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(55.0)	
Rates Revenue Requirement	**1,569.1**	**1,587.8**	**1,618.4**	
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	4.8	Exhibit H, Tab 1, Schedule 3
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,550.2**	**1,623.3**	
Year Over Year %		2.6%	4.7%	

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: The 2019 revenue requirement is based on proposed revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit

Exhibit Reference: E-1-1, Table 1.

The drivers of the increase in the 2020 revenue requirement compared the 2018 OEB approved revenue requirement are summarized by component in Table 4. The increase is predominantly driven by two years' worth of rate base growth and an increase in the regulatory deferral account balance being disposed of, which is partially offset by lower OM&A costs. The 2020 total revenue requirement is $49.6 million greater than the 2018 OEB amounts; however, the 2020 total revenue requirement is $16 million lower than what it would have been had the 2018 OEB approved revenue requirement been adjusted for inflation in 2019 and 2020[3].

Table 4: Changes to Individual Components of Rates Revenue Requirement Since Most Recent Rebasing

Description	**2020 vs. 2018 ($ millions)**	**2020 vs. 2018 (%)**
Increase in OM&A	-18.4	-1.2%
Rate Base Growth	80.1	5.3%
Lower cost of debt	-7.5	-0.5%
Tax	-4.6	-0.3%
Impact on Revenue Requirement	**49.7**	**3.3%**
External Revenue	-0.3	0.0%
Regulatory Deferral and Variance Accounts Disposition	63.2	4.2%
Total Change	**112.6**	**7.5%**

Exhibit Reference: E-1-1, Table 6

6.2 BUDGETING ASSUMPTIONS

In developing its Investment Plan, Hydro One utilized the Ontario Consumer Price Index ("CPI") for its assumptions about inflation. A CPI of 2% was assumed over the planning period. The Global Insight exchange rate forecast was used for other variables such as fleet vehicle related costs, which are typically obtained in US dollars. The exchange rate was forecast to range between 0.793 and 0.803 over the planning period. Further details

[3] The 2019 and 2020 total revenue requirements would be $1,656.3 and $1,689.4, respectively. This assumes that the 2018 OEB approved total revenue requirement is adjusted by an annual inflation rate of 2%.

regarding the economic assumptions underpinning the Investment Plan can be found in Section 2.1 of the TSP.

6.3 LOAD FORECAST SUMMARY

Hydro One uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential, commercial and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. This forecasting methodology was reviewed and approved by the OEB in previous Hydro One transmission rate cases and is detailed in Exhibit E, Tab 3, Schedule 1.

The proposed test period billing determinants arising from Hydro One's load forecast are summarized in Table 5.

Table 5: Hydro One's 2020-2022 Load Forecast (12-Month Average Peak in MW)

		Hydro One Rate Categories (Charge Determinants)		
	Ontario Demand	**Network Connection**	**Line Connection**	**Transformation Connection**
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

Exhibit Reference: E-3-1, Table 1

Table 6 summarizes the change in billing determinants as compared to 2018 OEB-approved amounts from the Prior Proceeding.

Table 6: 2018 vs. 2020 Changes in Billing Determinants

Year		Hydro One Rate Categories (Charge Determinants) (MW)		
	Ontario Demand	Network	Line Connection	Transformation Connection
2018 (OEB-approved)	20,378	20,410	19,746	16,876
2020	19,586	19,604	19,071	16,252
% Change	(3.9)%	(3.9)%	(3.4)%	(3.7)%

The proposed decrease in the 2020 charge determinant load forecast relative to the currently approved 2018 load forecast (per EB-2016-0160) results in an estimated 3.8% impact on rates due to load. The key drivers of the reduction in the 2020 load forecast are (i) the actual Ontario demand in 2018 was 3.5% lower than the forecast approved in the Prior Proceeding for the year 2018, and (ii) the Ontario demand is expected to further decline by 0.4% between 2018 and 2020 due to a combination of slow economic growth and conservation initiatives during this period.

The reduction in the actual load relative to the previously approved load forecast is primarily driven by the impact from the expanded Industrial Conservation Initiative (ICI) program on Ontario demand. In September 2016, the Government of Ontario expanded the ICI program to include more than one thousand newly eligible Class A customers with monthly peak demand greater than one megawatt, down from the previous eligibility threshold of three megawatts. Sector restrictions were also removed so that institutional and commercial businesses became eligible to participate. In April 2017, the Government of Ontario further reduced the ICI threshold from 1 MW to 500 kW to make Ontario consumers/market participants in targeted manufacturing and industrial sectors eligible to opt-in to the ICI. The reduction in peak demand driven by the new Class A customers participating in the ICI program was not reflected in Hydro One's approved load forecast for 2017 and 2018 in the Prior Proceeding.

6.4 TRANSMISSION SYSTEM PLAN

This section summarizes the major drivers and elements of Hydro One's 5-year TSP (Exhibit B, Tab 1, Schedule 1). It summarizes Hydro One's capital planning process and details the proposed capital spending over the planning period of the TSP. Hydro One has aligned the presentation of the capital expenditures in its TSP with the standard categories outlined in the OEB's *Consolidated Distribution System Plan Filing Requirements*[4] which are: System Renewal, System Access, System Service and General Plant.

Hydro One's Capital Planning Process consists of two interrelated functions. First is a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition, as well as identifying and scoping investment candidates ("Asset Management"). This is followed by a risk-based investment planning process through which investment candidates are reviewed, prioritized and optimized, and narrowed into an achievable set of planned investments

[4] Chapter 5 of the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications: Consolidated Distribution System Plan Filing Requirements*, dated July 12, 2018.

that help drive Hydro One towards achieving its intended outcomes ("Investment Planning").

6.4.1 ASSET MANAGEMENT

The Asset Management process encompasses the initial stages of Hydro One's Capital Planning Process. During this process, Hydro One undertakes extensive and detailed technical reviews of its assets to identify a set of investment candidates. Investment candidates are potential programs and projects that are put forth for further consideration during the Investment Planning process, which is discussed in the next section.

Hydro One's Asset Management process starts with a thorough and systematic review of its transmission investment needs. The needs assessment identifies and evaluates individual asset needs that drive the development of candidate investments and includes a risk assessment of the operational risks using the revised risk assessment framework. The needs assessment considers (i) asset needs, (ii) customer needs and preferences, (iii) system needs (including as identified through participation in regional planning), and (iv) other external influences. The needs assessment also identifies potential hazards, vulnerabilities, threats and other risk sources that could present obstacles to achieving Hydro One's business objectives.

Hydro One carries out an Asset Risk Assessment ("ARA") process to determine individual asset needs which rely on asset condition data, engineering analysis and other information, including the input of experienced planning professionals. The asset analytics system enables Hydro One planners to review aggregated information from various enterprise reporting systems. This drives efficiencies and effective planning decisions by ensuring a consistent view of asset information for all planners. The information contained within the asset analytics system includes condition information driven by deficiency and preventative maintenance reports, demographic information (including make, model, type and criticality to the transmission system), performance data based on equipment outages, utilization information, and economics. In essence, the quantitative asset analytics system combines information from various Hydro One databases to provide a common understanding of asset health to aid Hydro One planners in identifying asset risks and making asset lifecycle investment decisions to optimize risks and costs. Hydro One's planners also take into account additional factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets.

The ARA process is primarily concerned with the major equipment groups that directly affect system reliability, namely transformers, conductors, breakers, and protection and control systems, and evaluates them on the following six risk factors:

- Condition – Risk related to the increased probability of failure that assets experience when their condition degrades over time.
- Demographics – Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage.
- Criticality – Represents the impact that the failure of a specific asset would have on the transmission system.
- Performance - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages.
- Utilization - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized.
- Economics - Risk based on the economic evaluation of the ongoing costs associated with the operation of an asset.

When assessing individual asset needs, Hydro One's planners engage in a process of grouping identified needs into logical, functional and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, might be grouped together if the same transmission station is involved. Through this process, diverse individual needs are brought together to form potential projects or programs that may be brought forward as candidate investments. These groupings of potential candidate investments are then scoped and defined based on identified asset needs, customer feedback and other inputs.

As part of the process of developing candidate investments, on-site assessments are conducted to ensure factors such as the physical design/clearances/constructability and safety options requiring geographic flexibility, etc. are considered. During these on-site assessments, planners and field personnel validate and confirm asset condition and related information identified through enterprise reporting systems and asset analytics. Planners will speak directly with Hydro One personnel who are involved in the day-to-day management and maintenance of the equipment in order to get additional insights into deficiencies and asset needs.

For high-value assets, such as transformers, Hydro One's subject matter experts perform a thorough analysis, advise on issues such as equipment obsolescence and manufacturer support, and conduct "repair vs. replace" evaluations. All transformer replacements require review by subject matter experts who prepare Transformer Assessment Reports that are used to validate investment decisions.

The result of the aforementioned ARA process is that a portfolio of specific candidate investments is submitted for further consideration through the Investment Planning process. In that process, specific investments are prioritized to align with intended outcomes based on corporate priorities and strategic objectives, regulatory requirements, investment risks and identified constraints.

Hydro One's Asset Management and ARA process is described in greater detail in the TSP.

6.4.2 INVESTMENT PLANNING

Since the Prior Proceeding**,** Hydro One revised and implemented an improved eight-step risk-based investment planning process. Key improvements to the investment planning process include the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and
- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

The improved eight-step risk-based investment planning process is designed to provide a prioritized, consistent and common understanding of risk so as to enable Hydro One to cost effectively deliver the highest value investments and service for its customers. This allows candidate investments to be consistently assessed and prioritized based on the level of risk mitigated and the cost and value delivered toward achieving business objectives.

The Investment Planning process generates an annual budget for the Operations, Maintenance and Administration ("OM&A") work program and capital investments, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements for a consolidated five-year capital plan.

The Investment Planning process consists of the following steps:

1. Investment Planning Context: Hydro One draws on multiple sources of input in developing and prioritizing the investment plan consistent with Hydro One strategic priorities and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback, (iv) delivery of key outcomes, and (v) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;
2. Candidate Investment Development: Through the Asset Management process described above, candidate investments are identified, developed and submitted for possible inclusion in the investment plan;
3. Investment Assessment and Calibration: Investments are assessed for safety, reliability and environmental risk mitigation using clear and consistent risk taxonomies. Special non-risk considerations are also flagged (e.g. strategic, compliance). Once candidate investments have been assessed and flagged, the assessments are reviewed in facilitated discussions with investment owners in calibration sessions;
4. Prioritization and Optimization: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments. Following the initial prioritization and optimization, facilitated challenge sessions are held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs;

5. Enterprise Engagement: Executing lines of business review the investment plan for operational/execution feasibility, strategic alignment and to challenge investment needs and assumptions;
6. Develop Final Plan: Final decisions are made to arrive at a final version of the investment plan and its outcomes against strategic, customer, and risk considerations;
7. Review and Approval: The investment plan and associated outcomes are reviewed and approved by VPs, the Executive Leadership Team and the Hydro One Board of Directors; and
8. Execution and Performance Monitoring: The execution of the plan is monitored to ensure it is delivered as efficiently as possible.

The Investment Planning process is described in greater detail in Section 2.1 of the TSP.

6.4.3 CAPITAL EXPENDITURES

Table 7 below summarizes Hydro One’s planned capital expenditures by category over the TSP planning period along with the Progressive Productivity savings for each year. The 2020 capital expenditures, net of Progressive Productivity savings, represent a $192 million (or 19%) increase over 2018 OEB-approved levels.

Table 7: Bridge Year and Planning Year Capital Expenditure Summary

OEB Category	Historical			Bridge	Forecast				
	2018			2019	2020	2021	2022	2023	2024
	OEB Approved	F/Cast[5]	Var	F/Cast	Test	Test	Test	Plan	Plan
	$M	$M	%	$M	$M	$M	$M	$M	$M
System Access	24.3	35.8	47%	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	780.4	797.2	2%	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	75.6	79.1	5%	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	119.7	97.5	-19%	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity	0.0	0.0	0%	0.0	-17.0	-39.0	-61.0	-78.0	-91.0
Total	**1,000.0**	**1009.5**		**1,038.5**	**1,192.5**	**1,318.0**	**1,370.0**	**1,370.0**	**1,370.0**
System OM&A*	**394.3**	**399.4**	1%	**356.6**	**375.9**	*****	*****	**N/A**	**N/A**

** System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the RCI described in Section 4 of this Exhibit.*

Exhibit Reference – B-1-1, Section 3.3, Table 2.

Over the TSP planning period, Hydro One plans to spend approximately $6.6 billion in capital, representing an annual growth rate of 5.4% from 2018 OEB approved levels to restore transmission reliability performance to top quartile as compared to its Canadian peers[6], address customer needs and preferences and mitigate asset and operational risks. The proposed investments are targeted at the highest risk assets and will eliminate all critical safety and environmental risks.

The majority of the forecast spending in the TSP is in the System Renewal category and is for investments that are required to address the condition of critical assets and prevent

[5] 2018 values are based on a forecast. 2018 actuals will be provided in the Blue Page updated which is expected to be filed in mid-2019.
[6] As detailed in Exhibit D, Tab 2, Schedule 1, Hydro One's reliability performance is benchmarked with its Canadian peers with the Canadian Electricity Association.

further degradation of the overall fleet of assets as a result of demographic pressure that Hydro One is experiencing for key asset classes - primarily stations and lines.

Hydro One's TSP reflects the need for continued station renewal investments at a cost of $3.5 billion, or approximately 53%, of the total planned capital expenditures over the planning period, $1.9 billion of which is required over the test period to address deteriorated station assets including transformers, circuit breakers, protection, control and telecom equipment. Over the TSP planning period, these replacements are expected to approximately maintain the proportion of transformers on the system that are beyond their expected service life at 26%, approximately maintain the proportion of protection systems operating beyond their expected service life at 28% and maintain the number of breakers that are beyond their expected service life at 12%. This includes the replacement of 72% of the air-blast circuit breakers (ABCBs) at a cost of $594M. ABCBs are about 10 times more expensive to maintain and about 4 times less reliable than their equivalent SF6 circuit breakers.

The TSP also delivers an increased emphasis on line renewal investments at a cost of approximately $2.0 billion over the planning period, $1.2 billion of which is required over the test period, to refurbish and replace end of life transmission lines, underground cables, insulators and wood poles, while continuing with tower coating of steel structures to extend their useful life, but at a reduced pacing consistent with direction from the OEB in the Prior Proceeding. Detailed condition assessments are being conducted for lines exceeding 50 years of age to inform the line refurbishment program. While the planned rate of refurbishment does not keep up with lines demographics, the risk is managed by prioritizing line refurbishment investments based on detailed asset condition assessments. The pace at which a transmission line deteriorates varies depending on location and environmental and system conditions.

The TSP includes $947 million in proposed System Access and System Service capital that is required over the TSP planning period, $552 million of which is required over the test period, to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with customers, transmitters, distributors and the IESO. These investments will result in the addition of seven new transformer stations, ten customer-owned stations and 272 circuit km of new or upgraded transmission lines. Major projects include the development work for the North-West Bulk transmission expansion, new transmission switching and lines facilities to support load growth in the Leamington area, transformation and lines at Milton Switching station, and upgrades/expansion in Barrie and Toronto areas.

The TSP also includes $447 million of general plant capital that is required over the planning period, $304 million of which is required over the test period, to support day-to-day business and operations activities such as buildings, tools, equipment, rolling stock, as well as information technology hardware and software. This includes investing $189 million in operating infrastructure and control facilities. This amount includes the new Integrated System Operating Centre (“ISOC”), which represents an investment of $45 million over the planning period, as well as an upgrade to Hydro One’s Network Management System – used for grid control, and a refresh of Hydro One’s integrated voice communication telephony system.

Further details regarding the demographics of Hydro One’s transmission assets and the drivers of capital spending can be found in Chapters 2 and 3 of the TSP, respectively.

6.5 RATE BASE

The requested rate base over the test period is provided in Table 8 below. Details are provided in Exhibit C, Tab 1, Schedule 1. The 2020 rate base represents a $1,250.3 million (11%) increase over 2018 OEB-approved levels.

Table 8: Transmission Rate Base ($ Millions)

Description	OEB-approved	Bridge	Test		
	2018	2019	2020	2021	2022
Mid-Year Gross Plant	17,537.1	18,516.2	19,414.2	20,523.7	21,755.4
Mid-Year Accumulated Depreciation	(6,416.3)	(6,714.7)	(7,052.3)	(7,442.2)	(7,848.8)
Mid-Year Net Plant	**11,120.8**	**11,801.5**	**12,362.0**	**13,081.5**	**13,906.6**
Cash Working Capital	15.0	22.5	24.4	26.5	27.6
Materials and Supply Inventory	12.2	11.7	12.0	12.2	12.4
Transmission Rate Base	**11,148.0**	**11,835.7**	**12,398.3**	**13,120.2**	**13,946.6**

Exhibit Reference: C-1-1, tables 1 and 2

6.6 PERFORMANCE AND REPORTING

Consistent with the OEB's findings in the Prior Proceeding, Hydro One has included in the Application an improved Transmission Scorecard for approval by the OEB. The revised measures reflected in the scorecard are aligned with the OEB's performance outcomes under the RRF and have been influenced by internal and external factors, including Hydro One's past performance management measures, benchmarking studies, and scorecards and measures of other utilities in the public domain. In addition, Hydro One has set performance targets for the TSP planning period that reflect the expected outcomes of Hydro One's planned investments and show Hydro One's commitment to continuous improvement. The scorecard measures, along with their associated RRF performance outcomes, are shown in Figure 4. Further details regarding the proposed measures, along with Hydro One's historical performance and performance targets, are detailed in Section 1.5 of the TSP.

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)	
		Overall Customer Satisfaction (% Satisfied)	
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	
		T-SAIDI (Ave minutes of interruptions per Deliver Point)	
		System Unavailability (%)	
		Unsupplied energy (minutes)	
	Asset & Project Management	Transmission System Plan Implementation Progress (%)	
		CapEx as % of Budget	
		OM&A Program Accomplishment (composite index)	
		Capital Program Accomplishment (composite index)	
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	
		OM&A per Gross Fixed Asset Value (%)	
		Line Clearing Cost per kilometer ($/km)	
		Brush Control Cost per Hectare ($/Ha)	
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %	
		End-of-Life Right-Sizing Assessment Expectation	
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	
		Profitability: Regulatory Return on Equity	Deemed (included in rates)
			Achieved

Figure 4: Evolved Electricity Transmitter Scorecard Measures[7]

[7] Exhibit Reference: B-1-1, Section 1.5, Figure 1

6.7 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A) EXPENSE

A summary of forecast OM&A expenses for the 2020 test year is provided in Exhibit F, Tab 1, Schedule 1. These amounts have been reduced by the OM&A productivity savings outlined in Table 2 of this Exhibit. As shown in Table 9, 2020 OM&A expenses are expected to be $18.4 million lower (4.7%) than the 2018 OEB-approved (plan) funding envelope and are $34 million lower than what they would be if 2018 OEB-approved funding levels were increased at a 2% rate of inflation in 2019 and 2020.[8] OM&A reductions will be achieved through operating efficiencies, particularly the management of maintenance cycles, and a company-wide exercise undertaken by Hydro One to review and reduce corporate common costs. The review resulted in a significant commitment by business units to reduce corporate costs across the organization. These reductions were achieved primarily through a reduction in vacancies and by limiting consulting and contract engagements to critical functions, which also assist in strengthening and building internal capabilities. Hydro One's TSP is designed to utilize approved funding, in both capital and OM&A, to improve reliability and maintain asset condition over the planning period. In this manner, the plan appropriately balances customer rate impacts with the requirements of the system.

2019 OM&A expenditures are lower than the proposed test year OM&A as a result of the need to align to the funding envelope afforded in Hydro One's 2019 transmission revenue cap adjustment application (EB-2018-0130). This maintenance reduction has included reductions in activities including a one year extension of planned maintenance and asset

[8] 2018 OEB-approved OM&A inflated by 2% would have resulted in OM&A of $402 million in 2019 and $410 million in 2020

condition assessments and represents a managed increase in asset risk that may manifest in terms of increased corrective/demand failures and/or reduced asset useful life but can be contained with a one year reduction in work and will be managed and mitigated in future years. Hydro One expects safety and reliability performance to be maintained over the TSP planning period at the proposed funding levels. Further details regarding Hydro One's OM&A expenses can be found in Exhibit F.

Table 9: Summary of Transmission OM&A Expenditures ($ Million)

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Plan	Forecast	Forecast
Category Level										
Sustainment	233.6	238.7	215.1	241.1	218.1	241.2	221.3	238.5	200.6	214.2
Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	56.6	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	10.4	3.9	7.3	7.5
Common Corporate Costs and Other Costs[9]	73.9	70.2	60.1	71.3	41.5	49.9	41.1	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	64.7	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		

[9] *Common Corporate Costs and Other Costs* includes Planning, (exhibit F-02-03), CCF&S (exhibit F-02-02), Information Technology (exhibit F-02-04), Cost of External Revenue (exhibit F-02-05), and Other OM&A (exhibit F-02-01).

Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**399.4**	**394.3**	**356.6**	**375.9**
% Change Year over Year			-7.6%		-5.6%		3.7%		-10.7%	5.4%
Variance to Plan	10.4		-28.7		-12.7		5.1			

Exhibit Reference: F-1-1, Table 1.

The "Plan" values shown in Table 9 at an individual investment category level for the historical and bridge years reflect the funding levels previously proposed by Hydro One in applications to the OEB for the applicable years. Values at the category level have not been adjusted in response to reductions to the overall OM&A expenditure levels approved in the applicable OEB decisions as the OEB's findings were at an envelope level. As such, OEB-reductions are included as a separate line item under "Adjustments" and are reflected in the total transmission OM&A "Plan" values at envelope level for the historical and bridge years. For further details, please see Exhibit F, Tab 1, Schedule 1.

Hydro One will manage its OM&A budget over the test period to 2020 levels as adjusted by the RCI discussed in Section 4 above.

Hydro One's 2019 and 2020 total transmission-allocated compensation costs are summarized in Table 10. The 2020 transmission-allocated costs represent an 8.0% increase over 2019 levels. Increases are driven by negotiated wage increases in compensation for Hydro One's represented staff and due to additional resourcing requirements necessary to execute Hydro One's work programs which are increasing over the test period. These increases are offset by the reduction in vacancies for common corporate functions, noted above. Hydro One has revised the presentation of its compensation costs in consideration of the OEB's findings in the Prior Proceeding. Further details are provided in Exhibit F, Tab 4, Schedule 1, Attachment 1.

Table 10: Summary of Total Transmission-Allocated Compensation Costs ($)

	2019	2020	Change
Total Capital Transmission Comp	456,985,537	505,243,466	48,257,929
Total OM&A Transmission Comp	176,094,700	178,968,609	2,873,909
Total Transmission Compensation	**633,080,237**	**684,212,075**	**51,131,837**

Hydro One re-engaged Mercer (Canada) Ltd. to prepare an updated total compensation cost benchmarking study, a copy of which is provided as Attachment 2 to Exhibit F, Tab 4, Schedule 1. The study showed an improvement in Hydro One's benchmarked compensation costs relative to peers, as compared to the study that had been filed in the Prior Proceeding.

6.8 COST OF CAPITAL

Table 11 below summarizes the return of capital for the 2020 rebasing year.

Table 11: 2020 Cost of Capital

Amount of Deemed	($M)	%	Cost Rate (%)	Return ($M)
Long-term debt	6,806.2	54.9	4.52	307.7
Short-term debt	495.9	4.0	2.82	14.0
Deemed Long-Term debt	136.9	1.1	4.52	6.2
Common equity	4,959.3	40.0	8.98	445.3
Total	12,398.3	100.0	6.24	773.2

Exhibit Reference: G-1-1

Hydro One's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base. The 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt. Hydro One proposes to adopt the final 2020 return on equity and short-term debt rates as determined by the OEB for the purposes of determining its return on capital. The long-term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt to be issued. Further details regarding the cost of capital can be found in Exhibit G, Tab 1, Schedule 1.

6.9 COST ALLOCATION AND RATE DESIGN

Hydro One continues to follow the OEB-approved methodology from the Prior Proceeding to allocate the transmission rates revenue requirement into three rate pools: Network, Line Connection and Transformation Connection. The methodology is outlined in detail throughout Exhibit I1.

The rate pools are based on functional categories of assets and their associated costs. The allocation of the rates revenue requirement by rate pool is summarized in Table 12.

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

Year	Network	Line Connection	Transformation Connection	Total
2020	$974.7	$186.2	$462.4	$1,623.3
2021	$1,024.5	$195.7	$486.0	$1,706.2
2022	$1,075.8	$205.5	$510.3	$1,791.6

Exhibit Reference: I1-1-1, Table 2.

6.10 DEFERRAL AND VARIANCE ACCOUNTS

Hydro One requests disposition of a $14.5 million debit balance in the regulatory accounts detailed in Table 13. Hydro One Transmission is requesting disposition of the forecast Regulatory Account values as at December 31, 2018 (to be update with actual audited balances as part of blue-page update) plus forecast interest accrued in 2019, on the principal balances as at December 31, 2018 less any amounts approved for disposition in 2019 by the OEB in Hydro One's 2019 Transmission Rate Application (EB-2018-0130). Hydro One proposes to dispose of this balance as an adjustment to its revenue requirement over a three-year period, effective January 1, 2020.

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

Description	Forecast Balance as at Dec 31, 2019
Excess Export Service Revenue	5.7
External Secondary Land Use Revenue	(0.2)
External Stations Maintenance, E&CS & Other External Revenue	(0.0)
Tax Rate Changes	0.0
Rights Payments	0.0
Pension Cost Differential	(5.3)
Long-Term Transmission Future Corridor Acquisition and Development	0.0
CDM Variance Account	13.6
External Revenue – Partnership Transmission Projects Account	(0.0)
OEB Cost Differential Account	(0.0)
North West Bulk Transmission Line	0.8
Total Regulatory Accounts for Approval	**14.5**

NOTE: Balances shown are forecast values. Final audited balances will be provided in the Blue Page update planned for mid-2019.
Exhibit Reference: H-1-3, Table 1.

Hydro One is requesting approval to continue all existing accounts and to establish the following accounts, as detailed in Exhibit H, Tab 1, Schedule 2:

1. Earnings Sharing Mechanism (ESM) Deferral Account which proposes to record and share with customers 50% of any over-earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points realized during any year of the four-year test period; and
2. CCRA True-Up Deferral Account which proposes to track the differences between components of revenue requirement and actual results related to load true-ups performed in accordance with Transmission System Code section 6.5.3.

6.11 BILL IMPACTS

Exhibit I2, Tab 5, Schedule 1 provides the bill impacts that would result from approval of the Application along with illustrative bill impacts for 2021 and 2022. Table 14 shows the average 2020 bill impacts of the proposed changes in transmission rates revenue requirement and load forecast.

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

	2019*	2020
Rates Revenue Requirement ($ millions)	**$1,550.2**	**$1,623.3**
% Increase in Rates RR over prior year		4.7%
% Impact of load forecast change		3.8%
Net Impact on Average Transmission Rates		**8.5%**
Transmission as a % of Tx-connected customer's Total Bill		7.4%
Estimated Average Bill impact		***0.6%***
Transmission as a % of Dx-connected customer's Total Bill		6.2%
Estimated Average Bill Impact		***0.5%***

** 2019 revenue requirement is as proposed in Hydro One's 2019 Transmission Application (EB-2018-0130). Exhibit Reference: I2-5-1, Table 2.*

Approximately 3.8% of the average increase to transmission rates in 2020 resulting from the Application is driven by a reduction to Hydro One's load forecast relative the forecast currently underpinning rates, which is driven by factors that are beyond Hydro One's control as explained in Section 6.3 of this Exhibit. Of the remaining 4.7% of the average increase to transmission rates resulting from the Application, only 1.3% is due to proposed capital spending in 2020 that is placed in service that year. The remainder of the impact is predominantly driven by an increase in rate base from capital projects placed in service that were largely completed prior to the test period of the Application. The regulatory account balances credit position from the EB-2018-0130 proceeding is no longer being applied to offset the revenue requirement causing an increase which is mostly offset by the proposed decrease in OM&A spending levels.

The 2020 total bill impact for a typical Hydro One medium density residential (R1) customer consuming 400 kWh, 750 kWh and 1,800 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: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1800 kWh**
Total Bill as of May 1, 2018[1]	\$84.33	\$123.51	\$241.03
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	\$4.78	\$8.96	\$21.50
Estimated 2019 Monthly RTSR[2]	\$5.09	\$9.55	\$22.92
2019 increase in Monthly Bill	**\$0.12**	**\$0.23**	**\$0.55**
2019 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	\$5.50	\$10.32	\$24.77
2020 increase in Monthly Bill	**\$0.41**	**\$0.77**	**\$1.85**
2020 increase as a % of total bill	*0.5%*	*0.6%*	*0.8%*

[1]Total bill including HST, based on time-of-use commodity pricing effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).
[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and rates revenue requirement proposed in 2019 Transmission Application (EB-2018-0130).
[3]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 14, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Exhibit Reference: I2-5-1, Table 3.

The 2020 total bill impact for a typical Hydro One General Service Energy less than 50 kW (“GSe < 50 kW”) customer consuming 1,000 kWh, 2,000 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 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 May 1, 2018[1]	$201.89	$373.66	$2,606.65
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2019 Monthly RTSR[2]	$11.33	$22.67	$169.99
2019 increase in Monthly Bill	**$0.27**	**$0.55**	**$4.10**
2019increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$12.25	$24.49	$183.70
2020 increase in Monthly Bill	**$0.91**	**$1.83**	**$13.71**
2020 increase as a % of total bill	*0.5%*	*0.5%*	*0.5%*

[1]Total bill including HST, based on time-of-use commodity pricing effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).
[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and rates revenue requirement proposed in 2019 Transmission Application (EB-2018-0130).
[3]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 14, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Exhibit Reference: I2-5-1, Table 4.

7. CONCLUSION

Hydro One’s Application balances the needs of its system, assets and customer preferences regarding outcomes and rates. Hydro One has aligned its Application with the OEB’s expectations under the RRF and the feedback provided in the Prior

Proceeding. The Application reflects Hydro One's continued evolution towards becoming a best-in-class, customer-centric, commercial entity.

Hydro One's TSP will deliver outcomes that customers value in the form of improvements to reliability performance, the elimination of critical safety and environment risks and enabling the connection of customers and businesses in the growing communities in Ontario while balancing customer concerns over rate impacts.

2019-2024 Transmission Business Plan

December 14, 2018

PURPOSE-LED

VALUES DRIVEN

hydro one

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

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Strategy and Business Objectives

Hydro One is a purpose-led and values-driven company. Hydro One's Strategy may undergo a refresh in 2019 following the appointment of a new CEO. However, the refresh will continue to reflect Hydro One's core values that are integral to the company and to its communities, which are:

- Safety comes first;
- Stand for people;
- Empowered to act;
- Optimism charges us; and
- Win as one.

The following outlines Hydro One's Strategic Priorities which may be refined as part of the refresh process:

Government and Regulatory Relationships

- Maintain constructive, transparent relationships with governments and regulatory entities in all jurisdictions where we operate.
- Deliver on obligations mandated by government through legislation and regulatory requirements.

Customer Experience:

- Deliver industry-leading customer service, in response to identified customer preferences.
- Foster innovation in the business to adapt to changing customer requirements and market opportunities.
- Advance reconciliation and work proactively to build relationships with Indigenous peoples and communities based on understanding, respect and mutual trust.

Operational Effectiveness

- Invest in grid infrastructure and grid modernization to deliver a high level of reliability and quality to our customers.
- Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs.

Employees

- Maintain a safe and inclusive workplace for all employees.
- Foster a high level of employee engagement throughout Hydro One.

Financial Metrics

- Maintain a strong balance sheet to support continuing investment in our business.
- Invest in assets to better serve our customers.

Circumstances & Challenges

Hydro One Networks' (Hydro One or the Company) transmission assets form the backbone of Ontario's electricity system. The system serves approximately 98% of the province by capacity and covers some of the most challenging and diverse geographies in Canada. The Company's transmission system is comprised of approximately 290 transmission stations and approximately 29,000 circuit kilometers of high-voltage lines and towers operating at 500 kV, 230 kV or 115 kV. It represents approximately $11,148 million of OEB approved rate base, as of 2018. Hydro One's system transmits electricity from generation sources to load customers, including approximately 45+ transmission-connected local distribution companies (LDCs), Hydro One's own distribution system, and approximately 85 large industrial customers directly connected to the transmission system. It is linked to five jurisdictions adjacent to Ontario through 27 high-voltage interconnections.

Hydro One's transmission system is facing a period of rapid change with many challenges including:

1. Customer expectations relating to reliability and power quality continue to increase;
2. Customer needs and preferences for new innovative and low cost products and services (i.e. energy storage, electric vehicles, renewable generation, solar, microgrid, etc) are expanding in a way that is transforming the industry;
3. Portions of the current transmission system date back more than 50 to100 years with many assets coming due for renewal. Aging infrastructure and deteriorating asset conditions will require increased maintenance and renewal in the coming years to mitigate the risks to public/employee safety and system/customer reliability;
4. New government policy and regional infrastructure needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system in an environment that is encouraging more competition in the transmission business;
5. Increased focus on critical infrastructure protection and regulatory compliance requirements necessitate the need for additional system resiliency to mitigate the impacts of climate change, cyber-attacks and threats to physical security;
6. Eliminating assets containing PCBs and managing greenhouse emissions to meet environmental compliance requirements; and
7. Residential and small business distribution customers are experiencing increasing and, in some cases, unmanageable electricity bills. Bill increases have been driven by many factors, including conservation and demand management initiatives, embedded generation and a move away from coal generation to natural gas, nuclear and renewable generation. Increases to the transmission delivery portion of the bill are driven largely by the need to replace Hydro One's deteriorated assets and invest in the transmission system. While Hydro One does not control external factors, it is mindful of the overall impact these costs have had on customers and customers' willingness and ability to pay rates that support needed investment in Hydro

One's transmission system. Productivity improvement is core to our competitive position in the marketplace for improving economic efficiency and being able to reduce costs for the benefit of our customers and shareholders.

Business Objectives

Hydro One Transmission's business objectives are directly aligned with the Ontario Energy Board's (OEB) *Renewed Regulatory Framework* (RRF), as shown in the table below.

Hydro One's Values and Business Objective

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	• Provide 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

The Transmission System Plan delivers outcomes consistent with Hydro One's business objectives and strategies. The outcomes are summarized and documented in the sections following.

Customer Focus

Customer Needs and Preferences

For the Plan, Hydro One continued to leverage the comprehensive customer engagement work completed in the spring of 2017 along with its ongoing regular customer interaction. Based on the information collected during these processes, the following customer needs and preferences were identified:

- Customer priorities are as follows: safety, reliability, outage restoration, power quality, customer service, productivity and environmental stewardship.
- All business customer segments, particularly Local Distribution Companies (LDCs), prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for customers and the ability to plan ahead.
- Reducing the frequency of power interruptions is more important than reducing the duration. Most important is reducing the number of day-to-day interruptions.
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in Hydro One's 2017-2018 transmission rate application[1] by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option.

The Transmission Investment Plan for the period 2019-2024 incorporates the results of the customer engagement process, within the confines of the proposed constrained OM&A budget, while balancing system/asset needs, and risk mitigation in the following ways:

- As best able, optimizes the life of the existing assets while mitigating the risk to safety and to current service levels posed by asset deterioration;
- System and customer reliability are maintained amongst the company's peers for reliability performance;
- Addresses customer needs and preferences through new customer connections, and regional development to enable growth and system renewal to meet current requirements;
- Responds to customer power quality concerns by proactively monitoring power quality across the province and working with customers to resolve specific issues; and

[1] Proposed capital budgets were $1076 million for 2017 and $1122 million for 2018. The OEB ultimately approved capital envelopes of $950 million for 2017 and $1000 million for 2018.

- Incorporates increased cost reductions and productivity improvements totaling $785 million resulting in lower revenue requirement of $64 million (3.13%) by 2024 to offset the customer rate impacts of the proposed investment plan.

Impact of the Plan on Customer Rates and Bills

On March 16, 2018, the OEB advised Hydro One that rates for the distribution and transmission businesses should be considered in a single application. To facilitate this outcome, the OEB asked Hydro One to file the transmission application for a four-year test period (2019-2022) in order to align the applications and the test periods for future combined applications. Changes to Hydro One's organization in July and August 2018, combined with the OEB's request, resulted in Hydro One re-evaluating its Transmission Business Plan. To allow sufficient time for this review to occur, Hydro One filed a one-year application to adjust the 2019 transmission revenue requirement for inflation after adjusting for Bill 2 requirements. As a result, the rate estimates noted below span an anticipated three separate rate filings for the periods of 2019, 2020-2022, and 2023-2027, although the length of the latter period may be subject to future OEB direction.

Transmission Revenue Requirement	2018	2019	2020	2021	2022
Rates Revenue Requirement	**$ 1,511**	**$ 1,550**	**$ 1,620**	**$ 1,703**	**$ 1,791**
Rate Increase Required, excl Load		**2.6%**	**4.5%**	**5.2%**	**5.1%**
Estimated Load Impact		0.0%	3.8%	0.6%	0.7%
Rate Increase Required		**2.6%**	**8.3%**	**5.8%**	**5.8%**
Est Total Bill Impact (R1 customer - 8%)		**0.2%**	**0.7%**	**0.5%**	**0.5%**

The total bill impact for Hydro One medium density residential (R1) customers consuming 750 kWh monthly is determined based on the forecasted increase in the customer's Retail Transmission Service Rates.

The Transmission System Plan to Achieve Business Objectives

System Planning Process

Hydro One's Business Objectives as outlined in the strategy section are used in the evaluation of asset and other needs in order to inform and guide the development of investment candidates and execution of work. The Asset Management objective is to identify and scope the optimal timing of asset maintenance and capital investments so as to minimize incremental risks to Hydro One's Business Objectives, while minimizing total lifecycle cost and mitigating customer rate impacts. Asset strategies, based upon the characteristics and specific requirements of the various assets, guide the development of recommended maintenance plans. These lifecycle strategies support Hydro One's comprehensive investment planning process for the identification, prioritization and optimization of asset maintenance and capital investments.

Operational excellence is a critical element of the Hydro One Vision. Since the 2017-2018 filing, Hydro One has implemented several changes that address process concerns raised by intervenors and the OEB as summarized in the table below.

OEB Finding	Detailed Feedback	Actions Taken
Customer engagement	▪ Use customer engagement feedback to inform plan	▪ Earlier, more comprehensive customer engagement ▪ New risk taxonomies informed by customer engagement feedback
Deficiencies in prioritization	▪ Questioned prioritization and optimization process	▪ Clear, comparable new taxonomies drive investment scoring and prioritization brought to Distribution ▪ Risk scores used to maximize risk mitigation per dollar spent
Asset Condition Assessments	▪ Need a comprehensive asset condition process that informs the prioritization	▪ Risk scores are tied back to available condition assessments ▪ Updated inventory of assets and condition assessment strategy with identified opportunities ▪ Third-party assessments and data initiatives completed
Value Added in Review	▪ The plan did not change over seven months of review	▪ Multiple challenge sessions where the merits of individual investments are debated
Sequencing	▪ Plan was submitted for rate filing before Hydro One Board approval	▪ Sequencing issues addressed for multi-year performance based regulation applications
Internal Audit	▪ Planning process had outstanding internal audit items to address	▪ All original internal audit items are complete ▪ Follow up internal audit shows lower overall risk level and other recommendations have been addressed.
Work Program Delivery	▪ Hydro One had not historically delivered its capital and OM&A programs to OEB approved level	▪ Enhanced upfront engineering and planning deliverables ▪ Increased governance throughout investment lifecycle ▪ Improved estimating and scheduling tools and processes

Consistent with feedback received from the OEB, Hydro One has developed a new eight-step investment planning process as shown in the figure below. This new process is designed to provide a consistent and common understanding and prioritization of enterprise risks to cost effectively deliver the highest value for Hydro One and its customers. This allows candidate investments to be consistently assessed and prioritized based on level of risk mitigated, cost and value delivered to achieving business objectives. Investments are reviewed during enterprise challenge sessions to engage stakeholders from across the organization to review the non-risk merits of investments, including discussing potential trade-offs, strategic importance and management judgment.

The process generates an annual budget for Operations, Maintenance and Administration (OM&A) and capital investments, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements for a consolidated five-year capital plan. All investments are prioritized based on this risk-based process.

Hydro One's Investment Planning Process

The planning process consists of the following steps:

1. **Investment planning context**: Hydro One draws on multiple sources of input in the development and prioritization of the investment plan consistent with Hydro One Limited's Strategic Business Objectives and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback; and (iv) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;
2. **Candidate investment development**: Candidate investments are developed and submitted for inclusion in the investment plan;
3. **Scoring and calibration**: Investments are scored for reliability, safety and environmental risk mitigation using a clear and consistent scale based on new risk taxonomies. These taxonomies measure the probability and impact of specific risks and compare across investment types and sources of risk. Unique considerations are flagged (e.g. customer, compliance);
4. **Initial prioritization**: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization of investments. The initial plan is prioritized in a way that mitigates operational risks to an acceptable level based on the total risk scores for each investment;
5. **Enterprise engagement**: Executing lines of business review the investment plan for operational/execution feasibility, strategic alignment and to challenge investment needs and assumptions;
6. **Develop final plan**: Final decisions are made to arrive at a final version of the investment plan and its outcomes against strategic, customer, and risk considerations;
7. **Review and approval**: Investment plan and associated outcomes are reviewed and approved by VPs, Executive Leadership Team, and the Hydro One Board; and
8. **Execution and performance monitoring**: The execution of the plan is monitored to ensure it is delivered as efficiently as possible.

Transmission System Plan

The following sections within the Transmission System Plan are direct excerpts from the 2019-2024 Consolidated Business Plan. For completeness, they have been included to provide a seamless and consistent review of the 2019-2024 Transmission Business Plan.

As part of Hydro One's 2019 Revenue Cap IR application and the upcoming 2020 to 2022 Transmission Rates Application, Hydro One is developing a new five-year Transmission System Plan in accordance with the OEB's revised filing requirements under the RRF, which sets out Hydro One's anticipated capital plans for 2020 through 2024. Since capital expenditures are tied to Maintenance and Operations costs, the Transmission System Plan is based on certain assumptions related to the level of OM&A investment during the planning period.

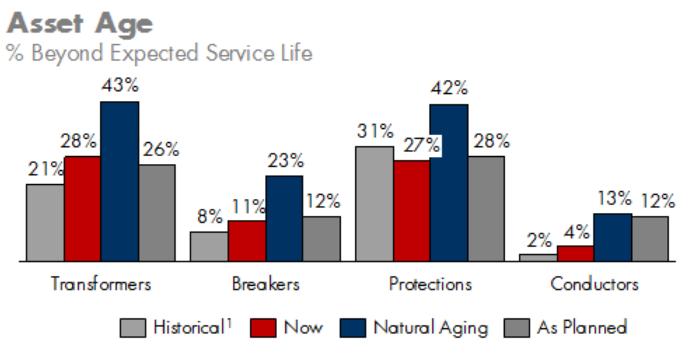
Hydro One's multi-circuit reliability performance is forecast to be Q2 by year end 2018 as compared to its Canadian Electrical Association (CEA) peers. This reliability performance is targeting to improve to Q1 performance by the end of the period.

The transmission customer satisfaction survey results indicate an improving trend, with a 2017 overall satisfaction rating of 85% and a 2018 overall satisfaction rating of 90%. Hydro One still faces challenges in the years ahead to address the needs of an aging transmission system, while maintaining and continuously improving in those areas valued most by its customers and stakeholders, including safety, reliability, outage restoration and power quality.

Hydro One's Transmission System Plan continues to strike a careful balance between: (i) asset related needs of the system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability and reliability risk; (iii) regional infrastructure needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) effect on customer rates.

Hydro One assesses and tests the condition of critical assets; the company continually improves this process through the assessment of asset performance (including failure investigations), improving data governance processes, industry engagement and input from third party experts. Stations and lines risk assessments are informed by the following: oil analysis, maintenance history, loading, ongoing inspection and monitoring information, reliability performance, age, obsolescence, remaining strength, ductility and net present value analysis.

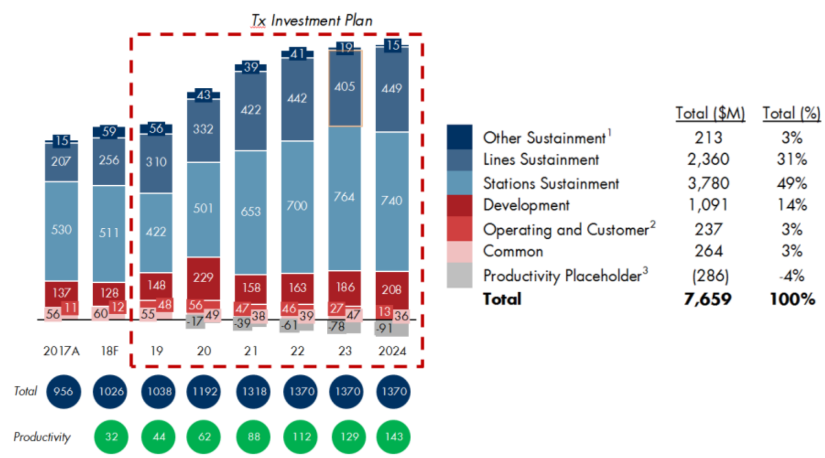
Based on Hydro One's assessment of its transmission system, a significant portion of the assets are reaching the end of their expected service life (ESL) and have deteriorated to the point where investment is required to maintain customer reliability and meet safety and environmental sustainability requirements. Through natural aging, it is forecast that 43% of transformers, 23% of breakers, 42% of protection systems, and 13% of conductors will reach their ESL over the next six years, as shown in the figure following. This evolving age profile is largely due to the significant system development in the 1950s and 1960s; these assets now require replacement.



[1]Historical as per Transmission Rate Application EB-2012-0031 filed May 28, 201

Transmission Capital

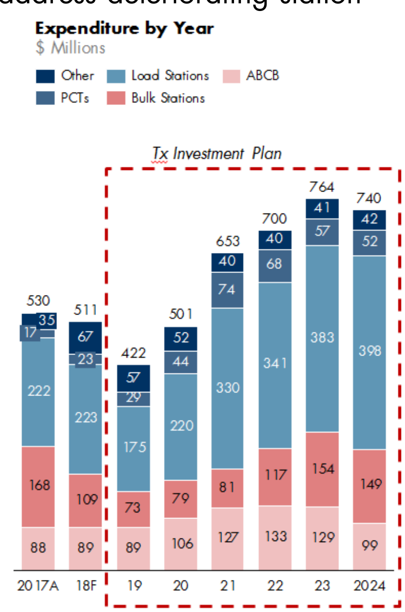
Over the planning period, Hydro one plans to spend approximately $7.7 billion in capital representing an annual growth of 5.7% over six years to improve transmission reliability performance, address customer needs and preferences, and mitigate asset and operational risks by delivering the capital work summarized described below. This Plan includes $577 million of capital productivity improvements through information technology, procurement, and process efficiency in executing the work to achieve required results.



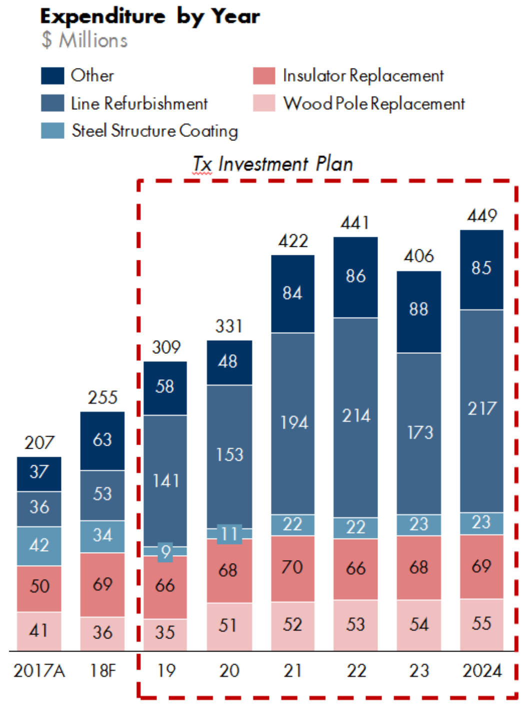
Hydro One's proposed System Plan reflects the need for continued investment in stations sustainment; approximately $3.8 billion (49%) has been included to address deteriorating station assets, including transformers, circuit breakers, and protection, control and telecom equipment. These replacements are expected to manage the fleet aging of major station assets during the Plan:

Assets that are Beyond Their Expected Service Life (ESL)

	Current State	Natural Aging over 6 Years	Impact of Plan
Transformers (Fleet=715 units)	28%	43%	26%
Breakers (Fleet=4,565 units)	11%	23%	12%
Protection, Control, Telecom (Fleet=12,108 units)	27%	42%	28%



Key renewal investments include the replacement of 95 air-blast circuit breakers (ABCBs) at a cost of $683 million. These older breakers are about ten (10) times more expensive to maintain and about four (4) times less reliable than their newer SF6 circuit breakers. Capital investment is also required to improve transmission station site facilities and meet new security requirements at a cost of $213 million. The station sustainment capital expenditures and program highlights over the Plan are summarized below:



- Replace 117 poor and deteriorated condition transformers at 54 transformers stations while eliminating 22 non-standard transformers;
- Replace 95 (68% of remaining ABCBs) obsolete and poor performing ABCBs and their associated high pressure air systems located at bulk electrical stations that are key for the reliable operation of the transmission system;
- Replace 2,638 obsolete, non-standard and poor performing protection devices; and
- Address new regulatory cyber security and physical security requirements at 53 stations.

The Transmission System Plan includes an increased emphasis on lines sustainment related investments at a cost of $2,360 million to refurbish and replace end of life transmission lines, insulators, and wood poles, and extending the useful life of steel structures through tower coating, but at a reduced pacing consistent with OEB direction in the 2017/2018 rate application.

As a result of natural aging, approximately 13% (~3,760 circuit-km) of transmission lines would be at their 90 year expected service life at the end of the planning period with no planned replacements. The line refurbishment program is informed by detailed condition assessments, which are conducted for lines exceeding 50 years. While the planned rate of refurbishment does not keep up with lines demographics, the risk is managed by prioritizing line refurbishment investments based on detailed asset condition assessment. The pace at which a transmission line deteriorates varies depending on location, environmental and system conditions.

The lines sustainment capital expenditures and program highlights are summarized below:

- Replace 1,830 circuit-km of end-of-life conductors on 71 circuits;
- Replace defective insulators on 21,450 critical circuit structures;
- Replace 4,650 (11%) end-of-life wood poles; and
- Tower coat 2,480 (10%) steel structures to extend their useful life.

The Transmission System Plan also includes $1.1 billion of development capital to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with large industrial customers, distributors and the Independent Electricity System Operator (IESO). This will result in the following system additions:

- Six new transformer stations, 14 customer-owned stations, and 470 new or upgraded transmission line circuit-km; and
- Major projects including the development work for the North-West Bulk Transmission Expansion, new transmission switching and lines facilities required to support the 1300+ MW load growth in the Leamington Area, transformation and lines at Milton Switching Station, and upgrades/expansion in Barrie and Toronto areas.

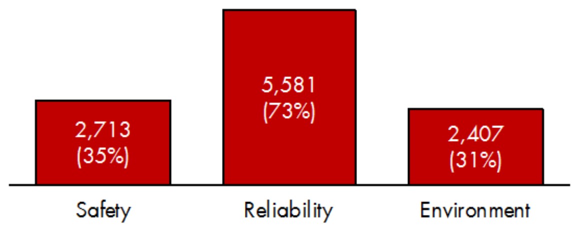
Some of the large Development projects have a high level of external uncertainty and projects such as the East-West Tie line construction have been excluded from the plan based on this uncertainty. The Niagara Reinforcement project, which had been stalled for a number of years, has resumed and is expected to be completed by mid-2019.

The new Integrated System Operating Centre (ISOC) will be constructed during this period in the City of Orillia to satisfy all safety-related and emergency preparedness requirements for both physical and cyber security. This investment is essential to maintaining adequate redundancy for operation of the Bulk Electric System and the Telecom Communication Network as required under North American Electric Reliability Corporation (NERC) EOP-008-2 "Loss of Control Centre Functionality" and Chapter 5, Section 11 of the IESO Market Rules.

In developing the Transmission System Plan, Hydro One considered 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. Hydro One expects greater outage scheduling constraints in the future that will make work more difficult to complete.

Safety, environment, and reliability risk mitigation are at the core of the Transmission System Plan. Hydro One strives to be an industry leader in safety and environment for its employees, contractors, and customers and to achieve and maintain "World Class" safety performance. This plan will maintain and improve reliability for customers and incorporates their input and priorities. Each investment is scored for safety, environment, and reliability risk mitigation on a clear and consistent scale. As well, each investment has the potential to address more than one risk factor. Reliability is a focus of this plan with $5.6 billion (73%) of the planned capital expenditures to mitigate reliability risk through the replacement of end of life assets or refurbishment, or system enhancement. $2.7 billion (35%) of planned capital expenditures will mitigate safety risk by replacing deteriorated assets in publicly accessible areas or through the replacement of equipment with known risks to employees. $2.4 billion (31%) is required to mitigate environmental risks, including the installation or refurbishment of oil spill containment facilities and the elimination of PCBs from the system by replacing contaminated equipment with >50ppm to comply with Federal Environmental legislation by 2025. These capital expenditures and the associated risk being mitigated are shown in the figure below.

Risk Driven Spend
$ millions 2019-2024, % of Transmission Capital spend



Hydro One is sensitive to the rate impacts of the investment plan on its customers as well as LDC's end-user customers, and has taken steps to ensure that its approach to investment is, and continues to be, in aligned with principles of the OEB's RRF by:

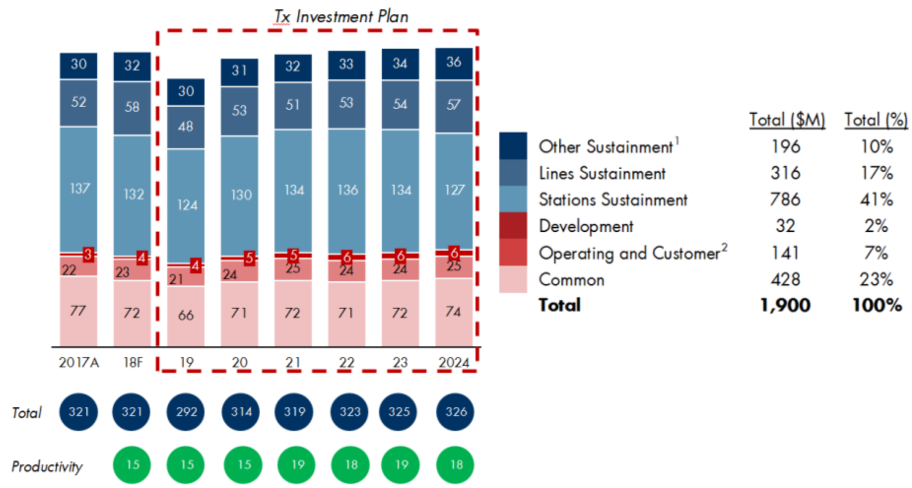
- ensuring that the Transmission System Plan reflects the consideration of customer needs and preferences identified in the customer engagement process and is consistent with the feedback obtained from various other customer consultations undertaken by the company including consultations with distribution customers;
- identifying specific opportunities (e.g. steel tower coating) where Hydro One can extend the useful life of its assets and mitigate higher capital spending requirements for asset replacements in the future;
- actively driving cost reductions and improved productivity savings to help offset customer rate impacts of the proposed investment plan;
- working with customers, transmitters, distributors and key stakeholders to ensure regional infrastructure issues and requirements are integrated; and
- implementing an improved performance management system to provide greater accountability for performance outcomes.

Hydro One's capital expenditure forecast is $1,026 million for 2019 and increasing to $1,370 million in 2024, representing an average annual increase of 5.7% over the planning period. The table below summarizes the capital investment plan.

Summary of Transmission Capital Plan

$mm	2017A	2018F	2019	2020	2021	2022	2023	2024
Stations Sustainment	530	511	422	501	653	700	764	740
Lines Sustainment	207	256	310	332	422	442	405	449
Other Sustainment	15	59	56	43	39	41	19	15
Development	137	128	148	229	158	163	186	208
Operating and Customer	11	12	48	56	47	46	27	13
Common	56	60	55	49	38	39	47	36
Progressive Placeholder	0	0	0	(17)	(39)	(61)	(78)	(91)
Total	**$956**	**$1026**	**$1038**	**$1192**	**$1318**	**$1370**	**$1370**	**$1370**

Transmission OM&A



OM&A expenditures are reduced by $29 million (9%) which aligns with the 2019 inflation application. This one year reduction will be achieved through sustained productivity gains, and a one-time extension of asset planned maintenance cycles. OM&A expenditures will increase in 2020 and the plan is designed to improve reliability and maintain asset condition over the planning period. In this manner, the plan appropriately balances customer rate impacts with the requirements of the system.

Transmission plans to spend approximately $1.9 billion in OM&A over the next six years, growing at approximately 2.2% per year despite a growing asset base and increasing compliance costs arising from new regulatory standards, such as the NERC Critical Infrastructure Protection and Cyber Security reliability standards. Embedded productivity improvements of $104 million are contributing towards the OM&A work programs to be delivered at less than inflation.

Summary of Transmission OM&A Plan

$mm	2017A	2018F	2019	2020	2021	2022	2023	2024
Stations Sustainment	137	132	124	130	134	136	134	127
Lines Sustainment	52	58	48	53	51	53	54	57
Other Sustainment	30	32	30	31	32	33	34	36
Development	3	4	4	5	5	6	6	6
Operating and Customer	22	23	21	24	25	24	24	25
Common Projects	77	72	66	71	72	71	72	74
Total	**$321**	**$321**	**$292**	**$314**	**$319**	**$323**	**$325**	**$326**

Transmission Sustainment OM&A

Stations OM&A

Stations maintenance programs will address corrective, preventative and refurbishment investments, as well as key compliance requirements related to NERC Compliance and PCB remediation.

Hydro One continues to deploy new tools and processes to improve operational performance. Through advanced condition assessment techniques, such as transformer dissolved gas analysis (DGA), Hydro One is able to reduce some maintenance programs as a result of additional insights. Some refurbishment work, such as ABCB auxiliary component remediation, will continue as these components are system critical and interface with key generators such as nuclear and hydro generating stations.

Through a temporarily revised preventative maintenance cycle analysis, the following maintenance programs will be reduced for one year to manage within the budget for the 2019 inflationary application: transformers, circuit breakers, switches, and tap-changers. This maintenance reduction represents a managed increase in asset risk that may manifest in terms of increased corrective/demand failures and/or reduced asset useful life but which will be addressed and mitigated in future years.

Corrective maintenance addresses unplanned failures along with defects identified through preventative maintenance and is funded at historical levels, in keeping with similar practice across Hydro One's assets. Corrective/demand failures will be mitigated through work prioritization and redirection in year.

Hydro One's protection, control and telecom (PCT) investment priorities include NERC compliance and demand / corrective maintenance which represents 40% of the PCT OM&A budget. Other maintenance cycles, such as re-verification of redundant protection and automation systems, will be extended similar to stations power equipment maintenance cycles identified above.

Addressing PCB contaminated equipment to comply with federal environmental legislation by 2025 is one of the largest OM&A investments over the plan period. The compliance requirements are to test, retrofill and dispose of PCBs and PCB contaminated equipment. Hydro One must be fully compliant by Environment Canada's December 31, 2025 deadline. There are currently 6,267 components (approximately 41% +/-5%) that require sampling, retrofill or replacement. In 2019, Hydro One deferred PCB work and now anticipate completing the required PCB remediation one year later by 2024, leaving only one year as contingency to complete the work by the 2025 deadline.

At these funding levels, Hydro One expects safety and reliability performance to be maintained. Risk associated with the one-time extension of the asset planned maintenance cycles will be addressed and mitigated in future years, beginning in 2020.

Lines OM&A

Transmission Lines maintenance programs focus on three areas:

- Vegetation management and right of way maintenance which account for 60% of the Plan;
- Overhead lines maintenance which accounts for 30%; and
- Underground cable maintenance which accounts for 10%.

With an aging asset population and past operating constraints, considerable backlogs have accumulated in various lines maintenance activities such as condition assessments, brush control, and line clearing programs. The priority of the Plan will be to address this backlog.

In 2019, Hydro One's vegetation maintenance program will be focused on all 230 kV and 500 kV corridors to maintain Hydro One's compliance with NERC Standard FAC-003, Transmission Vegetation Management. Hydro One will also focus on 115 kV corridors in the poorest condition and connected to critical customers but will reduce maintenance work on all other 115 kV corridors until 2020. In 2019, vegetation outages will be mitigated through work prioritization and the unplanned ROW maintenance program.

The overhead lines maintenance program will fund the condition assessment of assets that are currently beyond their testing age. Condition assessment results will be used to identify assets that have reached end of life and require replacement. Overhead inspections will also be completed on critical circuits located in publically accessible areas and those connected to critical customers. These inspections are used to identify transmission line components with major defects. Identified defects and any assets that reach end of life prior to condition assessment will be prioritized and mitigated through the overhead lines demand corrective program.

The underground cable investment work focuses on condition assessment through inspection, testing, analysis, patrol and diagnostics of the main cable and ancillary equipment used to support cable operation, associated corrective maintenance and cable locates. The vast majority of Hydro One's underground cables are located in major urban centers, including the downtown cities of Toronto, Ottawa and Hamilton. The plan, focuses on performing regulatory cable locates and high priority preventive and corrective maintenance on Hydro One's underground cables. Risk will be mitigated through the prioritization of non-critical planned corrective maintenance activities in conjunction with demand corrective program.

Corporate Costs

Hydro One utilizes a centralized shared services model to deliver common services to its Transmission and Distribution businesses and to its affiliated companies. Each business and affiliate pays their share of these corporate costs based on the output of a cost allocation methodology developed by Black and Veatch Corporation. The cost allocation methodology is approved for use by the OEB.

The table below summarizes the Corporate Costs that have been allocated to the Transmission business:

Corporate Costs ($mm) **Transmission (HONI)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Operations	65	64	66	67	69	69
Finance	21	22	23	23	24	24
Customer	12	12	12	12	12	12
Human Resources	12	12	13	13	13	13
Legal & Regulatory	14	14	15	15	16	16
Corp. Development	0	0	0	0	0	0
CEO[1]	2	2	2	2	2	2
Other (LTD)	1	1	1	1	1	1
Total	**$127**	**$128**	**$130**	**$133**	**$136**	**$138**

[1] Includes Chair, Board, Ombudsman, Enterprise Program Management Office, and Administration

Productivity in the Business Plan

Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the company. The Company has implemented a number of initiatives to reduce costs while maintaining or improving service quality and work outputs since the IPO. Quantifiable initiatives are included in the Plan and corporate scorecards with clear accountabilities for delivering the savings.

The process was executed in parallel with the business planning process. Each line of business was asked to identify initiatives that would have the potential to result in savings. In consultation with Finance, the lines of business were required to demonstrate that each proposed initiative would be capable of achieving demonstrable unit based savings, had a corresponding auditable measurement methodology, and was considered in the development of the Plan.

Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan. The largest value initiatives included in the 2019-2024 Transmission Business Plan are related to:

- More effective Sourcing and Fleet rationalization;
- More effective work execution by utilizing wrench time studies and overtime reduction
- Rationalization and renegotiation of the Outsourced IT Inergi contract
- Reduction of corporate costs
- Progressive undefined capital savings

Progressive productivity, presented in the following table as 'Tx Progressive' is a further reduction in cost that was applied to the final transmission investment plan in response to the concerns that were raised by the OEB regarding the pacing of investments in the 2017-2018 Transmission rate decision. The inclusion of these savings represents an incremental commitment from the company to find further efficiencies over the planning period without reducing work volumes.

The table summarized on the next page shows the cost savings anticipated from the initiatives that have been embedded in the 2019-2024 Transmission Business Plan, and major drivers are described below:

$mm	2018 F	2019	2020	2021	2022	2023	2024
Operations	32	44	51	61	63	61	62
Capital Total	**$32**	**$44**	**$51**	**$61**	**$63**	**$61**	**$62**
Operations	9	9	9	10	9	9	9
Information Technology	6	6	6	9	10	10	10
OM&A Total	**$15**	**$15**	**$15**	**$19**	**$18**	**$19**	**$18**
Operations	4	2	2	2	2	2	2
Other	2	20	19	16	14	11	9
Corporate Total	**$6**	**$22**	**$21**	**$19**	**$16**	**$14**	**$12**
Total Defined	**$54**	**$81**	**$87**	**$99**	**$97**	**$93**	**$92**
Progressive (Undefined)	0	0	11	27	49	68	81
Grand Total	**$54**	**$81**	**$98**	**$126**	**$146**	**$161**	**$173**
Prior Plan (2018-2023)		*$57*	*$73*	*$94*	*$115*	*$131*	
Plan Over Plan		*24*	*25*	*32*	*31*	*30*	

Operations

- The Telematics initiative will continue to deliver cost savings by identifying low utilization transportation & work equipment. Telematics, including the expected capital reduction from fleet rationalization, is expected to achieve $67 million of savings over the plan period.
- Various Procurement initiatives are expected to achieve $218 million of savings.
- Additionally a progressive productivity factor amounting to $237 million over the plan period has been included in the Operations investment plan for Transmission.
- As a result of optimized planning (overtime reductions) and improvement in wrench time, stations services will achieve efficiencies on corrective and preventative maintenance of $22 million over the plan period.

Information Technology

- Overall savings of $50 million are expected over the plan period primarily driven by the rationalization and renegotiation of the Outsourced IT contract with Inergi.

Transmission Scorecard

Hydro One's target performance outcomes in the Evolved Transmission Scorecard are developed in consideration of the RRF that the OEB has implemented for use in both Transmission and Distribution regulatory proceedings. The Evolved Transmission Scorecard is designed to provide additional transparency into the performance of Hydro One in these four areas:

- Customer Focus;
- Operational Effectiveness;
- Policy Responsiveness; and
- Financial Performance.

Hydro One has aligned the planning, execution and reporting functions to support the monitoring and achievement of established performance outcomes identified in the Scorecard.

Process to Develop Scorecard Metrics

In its Decision and Order (Decision) on Hydro One's 2017-2018 transmission rate application, the OEB issued its findings and directed Hydro One to file an evolved scorecard reflecting the OEB's feedback. The Evolved Transmission Scorecard presented below provides continuity with Hydro One's originally proposed Transmission Scorecard (EB-2016-0160), and reflects the OEB's feedback from the Decision.

Additionally, these metrics were influenced by internal and external sources that include Hydro One's past performance management metrics, benchmarking studies, scorecards, and metrics of other utilities in the public domain. The metrics were also informed by the OEB's guidance in the Handbook for Utility Rate Applications, using the following key considerations:

1. A focus on strategy and results, not activities;
2. The need to demonstrate continuous improvement;
3. Outcomes that are demonstrated to be of value to customers; and
4. Performance metrics that will accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

Hydro One has updated the targets in its evolved Transmission Scorecard to reflect continuous improvement and successful execution of the programs and projects in the Plan.

Evolved Transmission Regulatory Scorecard Results

							Target					
Performance Categories	**Measures**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)		86	92.0	89.0	94.0	85.0	85.5	86.0	86.5	87.0	87.5
	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	12.8	11.8	14.3	9.7	9.5	13.0	12.0	11.7	11.5	11.3	11.0
Customer Satisfaction	Overall Customer Satisfaction (% Satisfied)	81	77	85	78	88	86	88	88	88	88	88
Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	2.5	1.8	1.7	1.1	1.2	1.1	1.1	1.1	1.0	0.9	0.9
System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	0.57	0.60	0.59	0.46	0.65	0.58	0.57	0.56	0.55	0.54	0.53
	T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	0.69	0.48	0.50	0.33	0.47	0.53	0.52	0.51	0.50	0.4900	0.48
	T-SAIDI (Ave minutes of interruptions per Deliver Point)	64.9	36.7	43.9	80.8	42.8	46.5	45.59	44.68	43.79	42.91	42.05
	System Unavailability (%)	0.37	0.48	0.63	0.70	0.69	0.42	0.41	0.40	0.39	0.38	0.38
	Unsupplied energy (minutes)	20.9	12.2	11.8	11.4	13.2	12.6	12.36	12.11	11.87	11.63	11.40
Asset & Project Management	Transmission System Plan Implementation Progress (%)	94	99	105	100	94	100	100.0	100.0	100.0	100.0	100.0
	CapEx as % of Budget	73	90	106	105	100	100	100.0	100.0	100.0	100.0	100.0
	OM&A Program Accomplishment (composite index)			96.6	99.2	107.7	100	100.0	100.0	100.0	100.0	100.0
	Capital Program Accomplishment (composite index)			122.2	59.4	87.8	100	100.0	100.0	100.0	100.0	100.0
Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	7.6	8.4	9.0	8.6	7.9	7.7	7.3	7.8	7.9	7.7	7.3
	Sustainment Capital per Gross Fixed Asset Value (%)	3.3	4.2	4.6	4.6	4.4	4.3	4.2	4.3	5.1	5.0	4.7
	OM&A per Gross Fixed Asset Value (%)	2.7	2.7	2.9	2.5	2.3	2.2	1.8	1.8	1.7	1.6	1.5
	O&M Expenditure per Gross Book Value of In-Service Assets (%)	2.3	2.3	2.2	2.0	1.9	1.7	1.5	1.5	1.5	1.4	1.3
	Line Clearing Cost per kilometer ($/km)	1,805	2,495	2,234	1,966	2,100	2,295	2,295.0	2,264.0	2,200.0	2,175.0	2,100.0
	Brush Control Cost per Hectare ($/Ha)	1,703	1,624	1,566	1,542	1,356	1,625	1,625.0	1,620.0	1,630.0	1,608.0	1,608.0
Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	100	100	100	100	100	100	100.0	100.0	100.0	100.0	100.0
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %		100	100	100	100	100	100.0	100.0	100.0	100.0	100.0
	End-of-Life Right-Sizing Assessment Expectation			-	-	Met	Met	Met	Met	Met	Met	Met
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.80	0.69	0.13	0.20	0.13	N/A	N/A	N/A	N/A	N/A	N/A
	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.10	1.16	1.39	1.43	1.47	N/A	N/A	N/A	N/A	N/A	N/A
	Profitability: Regulatory Return on Equity	8.93	9.36	9.30	9.19	8.78	N/A	N/A	N/A	N/A	N/A	N/A
		13.22	13.12	10.93	10.02	9.03	N/A	N/A	N/A	N/A	N/A	N/A

Revenue Requirement

Transmission Revenue Requirement	2018	2019	2020	2021	2022
OM&A	394	398	359	365	370
Depreciation	469	474	488	519	545
Return on Debt	302	306	329	348	371
Return on Equity	401	406	446	473	503
Income Tax	57	58	53	56	57
Revenue Requirement	$ 1,624	$ 1,642	$ 1,675	$ 1,761	$ 1,846
Deferral and Variance Accounts	(58)	(38)	2	-	-
Other revenue impacts	(55)	(55)	(57)	(57)	(56)
Rates Revenue Requirement	**$ 1,511**	**$ 1,550**	**$ 1,620**	**$ 1,703**	**$ 1,791**
Rate Increase Required, excl Load		**2.6%**	**4.5%**	**5.2%**	**5.1%**
Estimated Load Impact		0.0%	3.8%	0.6%	0.7%
Rate Increase Required		**2.6%**	**8.3%**	**5.8%**	**5.8%**
Est Total Bill Impact (R1 customer - 8%)		**0.2%**	**0.7%**	**0.5%**	**0.5%**

Hydro One has taken steps to mitigate the impact of rate increases to customers. The increase in transmission rates in 2019 is largely attributable to the inflationary increase applied for in the 2019 transmission revenue requirement application, as well as changes in the disposition of deferral and variance account balances. Increases in rates during 2020-2022 are largely attributable to the declining load forecast, as described in the following section, as well as increases in depreciation and return on capital reflective of increasing rate base. These increases have been partially offset by decreased OM&A expenses. The rate increases indicated above are relative to the OEB approved revenue requirement for 2018, including the partial sharing of the deferred tax asset (DTA) with customers. As a result of Hydro One's motion to review and vary the decision, the treatment of the DTA is currently under review by the OEB. In the event the OEB alters its decision, the rate impacts noted above will change to reflect the new decision.

Load Forecast Summary

The table below sets out the 2019-2022 transmission system load forecast, which includes the impact of conservation and demand management and embedded generation.

Hydro One's 2019-2022 Load Forecast (12-Month Average Peak in MW)

Ontario Demand and Charge Determinants	OEB Approved					
	2017	2018	2019	2020	2021	2022
Ontario Demand	20,373	20,378	19,595	19,586	19,451	19,304
Network	20,405	20,410	19,614	19,604	19,469	19,322
Line Connection	19,741	19,746	19,078	19,071	18,941	18,800
Transformation Connection	16,872	16,876	16,258	16,252	16,142	16,021
Average YoY Load Impact		0.0%	-3.7%	-0.0%	-0.6%	-0.7%

The forecast was developed using a number of methods, such as econometric models, end-use models, customer forecast surveys and hourly load shape analysis. Hydro One's load forecast methodology has been reviewed and approved by the OEB. The forecast is weather normal, meaning that abnormal weather effects are removed from the historical base year to which forecast growth rates are applied. Consistent with the IESO's approach, normal weather data is based on the average weather conditions experienced over the last 31 years.

Key Financial Results

Following is a summary of principal financial outcomes for Transmission for 2019-2024.

Key Financial Results	2019	2020	2021	2022	2023	2024
Revenue requirement	$ 1,642	$ 1,675	$ 1,761	$ 1,846	$ 1,928	$ 2,005
Net income	$ 462	$ 499	$ 506	$ 530	$ 554	$ 568
Achieved ROE	8.46%	8.98%	8.98%	8.98%	8.98%	8.98%
Allowed regulatory ROE[1]	9.00%	8.98%	8.98%	8.98%	8.98%	8.98%
OM&A	$ 342	$ 359	$ 360	$ 363	$ 365	$ 381
Capital expenditures	$ 1,038	$ 1,192	$ 1,318	$ 1,370	$ 1,370	$ 1,370
Total rate base[1]	$ 11,844	$ 12,423	$ 13,162	$ 14,014	$ 14,838	$ 15,675
Total fixed rate debt to rate base	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%

[1]2019 Achieved regulatory ROE and total rate base notional given the Company has filed an inflationary application

CUSTOM IR APPLICATION SUMMARY

1. APPLICATION STRUCTURE

Hydro One's application is based on a Custom Incentive Rate-Setting ("IR") approach for a 3 year period. The methodology utilized is a Revenue Cap IR in which the revenue requirement for the test year t+1 is equal to the revenue requirement in year t inflated by the Revenue Cap Index ("RCI") set out below.

Hydro One's revenue requirement in the first year of the 3 year period (2020) is determined using a cost of service, forward test year approach, consistent with the OEB's Renewed Regulatory Framework ("RRF") as most recently set out in the *Handbook for Utility Rate Applications* (the "Handbook"), released by the OEB in October 2016. The revenue requirement in the following years, 2021 and 2022, is determined using an RCI that is calculated for each year.

The RCI includes an industry-specific inflation factor and two custom productivity factors. Consistent with the RRF, these productivity factors are explicitly included in the rate adjustment mechanism and provide an incentive for Hydro One to achieve capital and OM&A productivity improvements that are in addition to those imbedded in the Hydro One Transmission Business Plan in Exhibit A, Tab 3, Schedule 1, Attachment 1.

The RCI also includes a Custom Capital Factor ("C") that is designed to recover revenue related to new capital investments that are placed in-service in each test year, as further described in this Exhibit.

The Custom Revenue Cap Index (RCI) is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Transmission System Plan ("TSP"), beyond the amount of revenue recovered through the I – X adjustment.

In order to inform its RCI, Hydro One engaged Power System Engineering ("PSE") to:

- Perform an econometric Total Cost Benchmarking study for the purposes of developing a stretch factor recommendation;
- Determine the Total Factor Productivity ("TFP") trend for the electricity transmission industry for developing an X-Factor recommendation;
- Determine Hydro One's TFP trend for the purposes of assessing how Hydro One's performance compares to the historical performance of the transmission industry; and
- Determine the appropriate Labour and Non-Labour split for use in the industry-specific inflation factor.

Hydro One's overall approach is consistent with the RRF and is similar to the custom Price Cap Index methodology approved by the OEB in EB-2014-0016, for Toronto Hydro-Electric System Limited.

The Power Systems Engineering ("PSE") study included in this Application is an updated version of the analysis that was filed on the record in Hydro One Sault St. Marie's 2019 Revenue Cap IR application (EB-2018-0218). The forward-looking analysis of Hydro One's performance has been updated to reflect the Transmission Business Plan underpinning the Application. In addition, the study has been updated to reflect minor corrections arising from discovery in the EB-2018-0218 proceeding. No changes in the study methodology or model variables have been made relative to the PSE analysis that was placed on the record in EB-2018-0218. Further details regarding updates are provided in PSE's report which is included as Attachment 1 to this Exhibit.

1.1 INFLATION FACTOR

Hydro One is proposing an Inflation Factor ("I") based on the weighted sum of:

- 86% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The proposed weighting of 14% labour and 86% non-labour is supported by the recommendation provided by PSE in the study provided as Attachment 1 to this Exhibit.

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual inflation factor to be used by electricity distributors in incentive-based rate adjustment mechanisms. The Inflation Factor for distributors was based on a two-factor input price index comprised of the two indices noted above with component weights of 30% for labour and 70% for non-labour.

Given the similarities between the distribution and transmission businesses, Hydro One believes that it is appropriate to apply the same input price indices that are used to set the Inflation Factor for electricity distributors in Ontario to its transmission business. Hydro One notes its proposal is consistent with the OEB's recent decision in setting payment amounts for Ontario Power Generation's ("OPG") hydroelectric facilities (EB-2016-0152). In the OPG proceeding, the OEB approved an Inflation Factor based on an industry-specific weighting of the same input price indexes noted above.

The latest annual percent change for the GDP-IPI and the Average Weekly Earnings for Workers in Ontario was released by the OEB on November 23, 2018 for use in applications for rates effective in 2019. The derivation of Hydro One's proposed Inflation Factor is shown in Table 1 below.

Table 1: Derivation of Inflation Factor

	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Value - Annual Growth for the 2-factor IPI
Year	Q1	Q2	Q3	Q4	Annual	Annual % Change (A)	Weight (B)	Annual	Annual % Change (C)	Weight (D)	Annual % Change ([A*B]+[C*D])
2016	116.5	116.4	116.9	117.5	116.825			973.75			
2017	118.0	118.5	118.2	119.0	118.425	1.4%	86%	992.55	1.9%	14%	1.4%

Hydro One has used the Inflation Factor of 1.4% derived above, on a pro-forma basis in its RCI calculation for each of the 2021 and 2022 test years, for the purpose of this Application. The Inflation Factor will be updated annually based on the methodology above to reflect the actual annual percent changes for each index that are made available by the OEB when it sets the Inflation Factor for distributors in each of 2020 and 2021, effective 2021 and 2022, respectively.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor ("X") is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor. Hydro One engaged PSE to undertake a study of the TFP trend for the electricity transmission industry and to undertake an econometric total cost benchmarking study of Hydro One's total transmission costs in order to recommend a Custom Productivity Stretch Factor. The PSE study is provided as Attachment 1 to this Exhibit.

Based on the PSE study, Hydro One's proposed Productivity Factor of 0% reflects the sum of the Custom Industry Total Factor Productivity measure of 0% and a Custom Productivity Stretch Factor of 0%.

PSE's study determined an electricity transmission industry TFP of -1.45%. Despite the negative industry TFP, PSE proposed a Custom Industry Total Productivity Factor of 0% consistent with the OEB's decision in EB-2010-0379.

PSE recommended a Custom Productivity Stretch Factor of 0%. In PSE's total cost benchmarking analysis, Hydro One's projected total costs were determined to be approximately 27.1% below benchmark throughout the Custom IR period. Consistent with the approach under the OEB's 4th generation IRM, PSE recommended a stretch factor of 0%. This recommendation was based on Hydro One's strong cost performance and the adoption of 0% for Hydro One's Custom Industry Total Productivity Factor. PSE's rationale is further explained in Attachment 1 to this Exhibit.

The Productivity Factor used in the RCI will not be updated annually over the 2021 to 2022 portion of the Custom IR term. In its total cost benchmarking study, PSE conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected total costs would remain below benchmark expectations and Hydro One's internal TFP would remain above that of the industry. Further details can be found in PSE report provided in Attachment 1 to this Exhibit.

1.3 CAPITAL FACTOR

The Custom Capital Factor proposed in this Application and used in the RCI is designed to ensure that total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in Hydro One's TSP (Exhibit B, Tab 1, Schedule 1).

The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers. This includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The Capital Related Revenue Requirement (line 6) each year is based on the change in rate base.

The calculation of the Custom Capital Factor ("C") is set out in Table 2 below.

The Total Capital Related Revenue Requirement metrics in lines 1 to 8 of Table 2 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. These metrics will not change over the term of the Custom IR. The Total Revenue Requirement (line 11 of Table 1) will change annually, as a result of the annual adjustment to the Inflation Factor.

The OM&A (line 9) provided for each year in Table 2 is determined based on the 2020 forecast provided in the Application increased by the Inflation Factor ("I") and reduced by the proposed Productivity Factor ("X"), for a total increase of 1.4% per annum.

Table 2: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2020	2021	2022
1	Rate Base	C-1-1	12,398.3	13,120.2	13,946.6
2	Return on Debt	E1-1-1	327.9	347.0	368.8
3	Return on Equity	E1-1-1	445.3	471.3	501.0
4	Depreciation	F-6-1	471.5	502.4	528.4
5	Income Taxes	F-7-2	52.7	55.8	56.8
6	Capital Related Revenue Requirement		1,297.5	1,376.5	1,455.0
7	Less Productivity Factor (0.0%)			-	-
8	**Total Capital Related Revenue Requirement**		**1,297.5**	**1,376.5**	**1,455.0**
9	OM&A	F-1-1	375.9	381.2	386.5
10	**Total Revenue Requirement**		**1,673.4**	**1,757.7**	**1,841.5**
11	Increase in Capital Related Revenue Requirement			79.0	78.5
12	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.72%	4.47%
13	Less Capital Related Revenue Requirement in I-X			1.09%	1.10%
14	**Capital Factor**			**3.64%**	**3.37%**

The 2020 Total Revenue Requirement of $1,673.4 million (line 11) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2021, the Capital Related Revenue Requirement (line 6) increases to $1,376.5 million from $1,297.5 million in 2020. Hydro One will reduce the Capital Related Revenue Requirement (line 6) by the approved Productivity Factor. For the reasons outlined above, the proposed Productivity Factor is 0.0%. The change in Total Capital Related Revenue Requirement (line 8) in 2021 versus 2020 is $79.0 million (line 11). This difference is equal to 4.72% of the 2020 Total Revenue Requirement of $1,673.4 million ($79.0 million divided by $1,673.4 million).

The 4.72% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2021 Capital Related Revenue Requirement (line 6). However, the 4.72% increase must be reduced by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement (line 8) that is already provided for by the Inflation and Productivity Factors. In 2021, this equals 1.09% ($1,297.5 million x 1.4% / $1,673.4 million). The net result of 3.64% (4.72% less 1.09%) is the 2021 Custom Capital Factor. The calculation of the Custom Capital Factor for 2022 is the same, as set out in Table 1 above.

1.4 REVENUE CAP INDEX SUMMARY

Table 3 below summarizes the custom RCI by component that Hydro One is proposing to use in this Application to determine the total revenue requirement for rate-making purposes for 2021 and 2022.

Table 3: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2021	2022
Inflation Factor (I)	1.40	1.40
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	3.64	3.37
Custom Revenue Cap Index Total	5.04	4.77

The Inflation Factor in Table 3 will be updated annually, as described in section 1.1 of this Exhibit. Hydro One proposes that the Productivity Factor will remain unchanged throughout the Custom IR term and that the 2021 and 2022 Capital Factors approved in this application would remain unchanged in subsequent annual update applications.

Table 4 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Table 4: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2020	Cost of Service	$1,673.4 million
2021	2020 Revenue Requirement x 1.0504	$1,757.7 million
2022	2021 Revenue Requirement x 1.0477	$1,841.5 million

** Calculations assume that Inflation Factor remains at 1.4% through term.*

2. ADDITIONAL CUSTOM IR FEATURES

Hydro One is proposing the following additional features in this Application to align its interests with those of customers and provide an additional element of protection for customers.

2.1 EARNINGS SHARING MECHANISM (ESM)

Hydro One proposes to share with customers 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE for a test year will use the OEB approved mid-year rate base for that period to avoid double counting with amounts in the proposed capital in-service variance account, described below.

2.2 CAPITAL IN-SERVICE VARIANCE ACCOUNT (CISVA)

A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year. If in-service additions in a test year are less than the OEB-approved level, the balance of the account would be negative and refunded to customers in a future rate-setting period. If actual in-service capital additions are equal or greater than the OEB-approved level in the test year, no entry would be recorded in the account.

Hydro One is proposing a CISVA with the following key features:

1. The account will track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;
2. For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and
3. At the end of the three-year term of the Custom IR Plan, in 2022, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;
   - Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
   - Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers

Hydro One believes that a dead band is appropriate for the capital in-service variance account in order to ensure alignment between the behaviours that are incented by the account and the outcomes that rate payers value. The in-service variance account should incent Hydro One to cost-effectively deliver on its plans in a timely fashion while providing rate payers with protection from over-paying in the instance that Hydro One does not substantially deliver on its proposed in-service targets.

Absent the 2% dead band, Hydro One is incented to fully spend 100% of its planned capital amounts and focus on identifying any additional productivity initiatives on OM&A programs where part of the savings can be kept by the utility. Additionally, Hydro One is incented to do whatever it can (e.g. pay for additional overtime) to ensure planned projects are in-serviced by December 31st of each year rather than minimizing the execution cost. Though customers are not materially impacted if a project is in-serviced on December 31st as opposed to January 3rd, Hydro One would be financially impacted.

By including the 2% dead band, Hydro One is incented to find ways to lower the cost of capital projects, as well as OM&A, while still affording the sharing of benefits of significant cost savings with customers. The proposed 2% dead band was chosen because it has minimal impact on customers, while incenting behaviour that better aligns with the outcomes that rate payers value and is consistent with the OEB's outcomes-based approach under the Renewed Regulatory Framework.

3. Z-FACTOR

Hydro One is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available over the term of this Custom IR Application. This is consistent with the principles of the RRF. The criteria that would apply to the use of the Z-factor mechanism are those outlined by the OEB in Chapter 2 of the Filing Requirements for Electricity Transmission Applications and the guidelines provided in section 2.6 of the OEB's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (July 14, 2008).

Events that may necessitate the use of the Z-factor mechanism include:

- Extreme weather events such as storms;
- Investments that are government-mandated or otherwise outside of management's control;
- Changes to IESO market rules;
- Changes to OEB codes, policies or other directions;
- Changes to accounting frameworks or technical standards;
- Changes to government policy, legislation, or regulation, such as environmental laws; and
- Any other one-time or ongoing events that meet the Z-factor criteria.

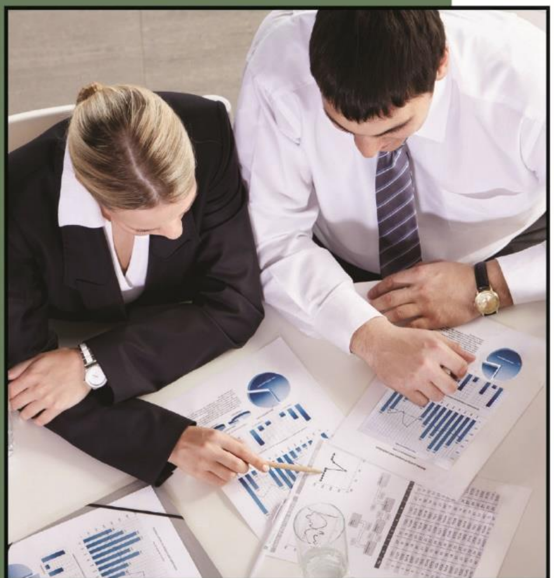
4. OFF-RAMPS

Hydro One proposes to apply the OEB's existing policy with respect to off-ramps. The Handbook states that, although the purpose of incentive regulation is to drive productivity improvements within the utility, customers must also be protected from utility earnings that become excessive. Hydro One is therefore proposing to adopt the OEB's existing off-ramp mechanism; a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review of the Revenue Requirement arising from Hydro One's Custom IR may be initiated.

5. PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications in 2021 and 2022. These applications are expected to be filed by the deadline for electricity distribution IRM applications seeking a January 1st effective date which has typically been near the end of August. These applications would calculate the revenue requirement using the RCI to reflect the most up to date Inflation Factor, as derived using the methodology described in section 1.1 and provide revised Uniform Transmission Rate calculations that reflect the revised revenue requirement. In the event that deferral and variance account balances accumulated in subsequent years are material, Hydro One may also seek to dispose of any balances in its annual update applications.

Power System Engineering, Inc.
Full-service consultants



Transmission Study for Hydro One Networks:

Recommended CIR Parameters and Productivity Comparisons

Prepared by:

Power System Engineering, Inc.
January 24, 2019

Transmission Study for Hydro One Networks:

Recommended CIR Parameters and Productivity Comparisons

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1 Executive Summary

This report has been revised from the Power System Engineering, Inc. (PSE) report filed in the Hydro One Sault Ste. Marie LP (SSM) application found in EB-2018-0218. Our recommendations regarding the customer incentive regulation parameters remain unchanged and our findings are similar to the report previously filed. No changes to the study have been made except the modifications which are listed and explained below.

1. Hydro One Networks provided PSE with a revised business plan that includes modified OM&A and capital spending levels for the projected years of the study.
2. A second modification has occurred due to PSE identifying peak demand data that was incorrectly reported by the three Southern Companies (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. This data has now been corrected.[1]
3. The third modification are slight revisions in plant additions in 2016 and 2017 made by Hydro One.
4. The incentive regulation period moves to 2020 to 2022 which means the OM&A spending is now escalated for 2021 and 2022 by I-X using the 2020 test year expenses rather than 2019.
5. Two minor corrections in the code were made relative to the prior research. The first is we are now calculating the asset prices prior to 1963 in calculating the capital benchmarks. The second is including only the observations in the TFP sample when aggregating the TFP components.[2]

These five modifications have been incorporated into this revision and are the only changes made to the dataset and study methodology relative to the research filed EB-2018-0218 and EB-2018-0130.

1.1 Overview of Study

Power System Engineering, Inc. (PSE) was engaged by Hydro One Networks, Inc. (Hydro One) to conduct an empirical study of Hydro One's transmission operations. The three main areas studied were:

1. Total cost levels,
2. Total factor productivity (TFP) trends, and
3. Custom incentive regulation (CIR) parameters.

Results from the first two areas (total costs and TFP) informed the recommended CIR parameters.

For the first area, PSE conducted an econometric benchmarking study of Hydro One's total costs. For the second area, TFP, we calculated the TFP trend of both Hydro One and that of the U.S. electric transmission industry. To develop recommendations for Hydro One's CIR parameters,

[1] This adjustment moved the TFP annual trend upwards by around 0.42%.

[2] Both corrections had a minimal impact on the results with the effect of the change being a slightly lower TFP trend by around 0.16%.

PSE used selected results from the total cost and TFP studies and determined the appropriate weights to use for the inflation factor. PSE used the results of the study to:

- Make recommendations regarding the custom incentive regulation (CIR) parameters that should be used in Hydro One's CIR application, and
- Assist the Ontario Energy Board (the Board) and stakeholders in assessing the reasonableness of the projected transmission cost levels contained in Hydro One's CIR application.

The following table specifies which study items are used to formulate the specific CIR recommendations.

Table 1 Research Items

Research Item	Used for:
1. Econometric Total Cost Benchmarking	Developing a stretch factor recommendation and assessing historic and projected CIR cost levels.
2A. Industry TFP Trend	Developing an X Factor recommendation in the CIR plan.
2B. Hydro One TFP Trend	Assessing the projected CIR cost levels and how the TFP trend for Hydro One compares to the historical norm for the industry.
3. Labour and Non-Labour Split	Inflation Factor recommendation

The report results should be helpful to stakeholders in assessing the reasonableness of the projected spending levels of Hydro One's transmission operations. The total cost benchmarking shows how Hydro One's total costs compare to the industry's costs, after empirically adjusting for service territory differences. The TFP trends of Hydro One and the industry provide the ability to compare how Hydro One's TFP has changed over time, relative to how the industry's TFP has changed. Stakeholders can also examine Hydro One's anticipated TFP trend during the CIR period, and compare that TFP trend to the industry's historical TFP trends.

In the three sub-sections that follow (1.1.1, 1.1.2, and 1.1.3) we give a brief overview of the three main study areas. In subsequent sections (1.2, 1.3, and 1.4) we provide an overview of the research findings in the study areas.

1.1.1 Econometric Cost Benchmarking Research: Overview

The econometric total cost benchmarking research is used as the basis for the stretch factor recommendation and to assist the Board and stakeholders as they evaluate the spending levels of

Hydro One. The use of econometric total cost benchmarking research to set stretch factors for electric distributors was established by the Board's Decision in the 4th Generation Incentive Regulation (4GIR) proceeding (EB-2010-0379).[3] PSE has modified the variables and sample to accommodate a transmission total cost econometric study. We have retained the basic benchmarking methodology of the 4GIR proceeding.

1.1.2 TFP Research: Overview

The industry TFP trend research is used as the basis for the X Factor recommendation. The 4GIR Decision used industry-wide TFP to establish the X Factor for distributors' price cap formulas. Similarly, Hydro One's revenue cap formula should also include an X Factor based on an estimate of electric transmission industry-wide TFP. The economic theory for the revenue cap formula is provided in Section 2.

After the industry TFP trend is established, the Hydro One TFP trend research is used to compare the company's own TFP trend to that of the industry. PSE's research provides the Board and stakeholders with the historical and projected TFP trends of Hydro One. However, for any given utility, the company's own TFP trend should not be used in setting its X Factor. Incentive regulation principles dictate that a proper analysis should use an industry TFP measure that is largely external to the utility to which it is being applied.

The historical period for both the benchmarking and TFP studies is 2004 to 2016. Hydro One projections are shown from 2017 to the end of the CIR period in 2022.[4] The industry sample is composed of 56 United States transmission investor-owned utilities for the benchmarking sample and 47 utilities for the TFP sample.[5]

1.1.3 CIR Inputs: Overview

In this report, PSE makes recommendations for the factors in the CIR formula, including the inflation factor, the X factor, the output growth factor, and the stretch factor. One important aspect of the inflation factor is the labour/non-labour split.

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[3] November 21, 2013, EB-2010-0379, *Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.*

[4] 2017 actual costs have been inserted for Hydro One, but other variables are based on projections for 2017.

[5] With Hydro One included, the number is 57 utilities in the benchmarking sample and 48 in the TFP sample. The TFP sample is smaller than the total cost benchmarking sample, because for the TFP analysis, utilities need an observation in every single year of the sample period. In other words, for TFP analysis we need a balanced panel—we could not use any utility that had missing data in any one of the years 2004-2016. This contrasts with the benchmarking model where, if data is unavailable for a specific year for a specific utility, that year can be omitted (while still using other years for that utility), resulting in an unbalanced panel estimation. All utilities in the TFP sample are also in the benchmarking sample.

In the Board's September 28, 2017 Decision for Hydro One Sault Ste. Marie, LLP (Hydro One SSM) regarding the company's application for electricity transmission, the Board stated that evidence on the appropriate input weights for the inflation factor should accompany future rate applications by Hydro One SSM.[6] In the Hydro One SSM application, the company put forth the same input weights as used for the distributors in 4GIR. The distributors' inflation factor has a 70% weight on non-labour and a 30% weight on labour. PSE was tasked with providing evidence for revising these weights to better align with the electric transmission industry.

To accomplish this task, PSE estimated the annual labour costs in the benchmarking sample. We then divided the estimated labour costs by the total costs for each observation and took an average of this percentage. Our findings suggest a 14% weight on the labour component and an 86% weight on the non-labour component.

1.2 Total Cost Benchmarking: Findings

Using a sample of 57 transmission utilities, PSE estimated a translog total cost econometric model that captures the relationship between total transmission costs and a set of variables. The variables are described in Section 3.2 . As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence.[7] PSE applied the translog functional form, which is the same functional form we used in Hydro One's distribution total cost benchmarking study.[8] However, the explanatory variables are different, and the distribution sample included numerous U.S. rural electric cooperative distributors to help capture the impacts of a distribution system serving low customer density areas.

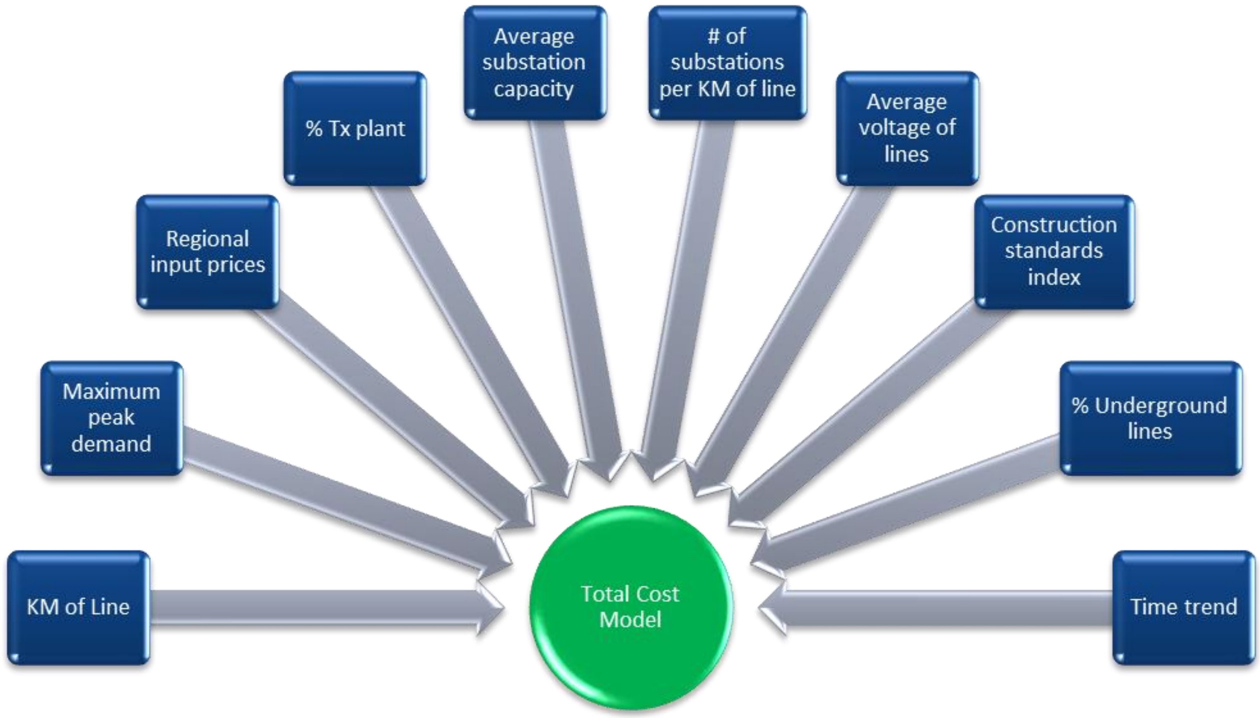
The variables included in the total cost model are illustrated in the following figure. These variables (also known as cost drivers) are included in the total cost model to correlate total cost with the variables and enable adjustments for the specific service territory circumstances encountered by Hydro One. For a more detailed description of the included variables, please see Section 3.2.

[6] EB-2016-0356, *Decision and Order* dated September 28, 2017, p. 5.

[7] In fact, all first order variables in the model are statistically significant at the 99% confidence level.

[8] This report can be found in case EB-2017-0049. The PSE report is titled, *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022)*. May 18, 2017.

Figure 1 Total Cost Model Variables



The benchmark scores are derived by taking the logarithmic percentage difference between Hydro One's actual total costs and their model-predicted total costs. A negative number implies that the company's actual costs are lower than the benchmark (i.e., lower than expected for an average utility with that company's operating circumstances). Table 2 and Figure 2 show Hydro One's scores for the historical and projected years.

Table 2 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,319,202	$1,500,514	-12.9%
2005	$1,372,128	$1,638,703	-17.8%
2006	$1,453,435	$1,773,126	-19.9%
2007	$1,586,919	$1,916,996	-18.9%
2008	$1,669,115	$2,108,130	-23.4%
2009	$1,783,173	$2,194,844	-20.8%
2010	$1,805,110	$2,206,257	-20.1%
2011	$1,984,174	$2,448,930	-21.0%
2012	$2,112,358	$2,584,997	-20.2%
2013	$2,097,031	$2,562,385	-20.0%
2014	$2,120,542	$2,620,081	-21.2%
2015	$2,227,713	$2,750,068	-21.1%
2016	$2,281,074	$2,876,130	-23.2%
2017 (projected)	$2,335,312	$2,995,513	-24.9%
2018 (projected)	$2,428,965	$3,118,802	-25.0%
2019 (projected)	$2,450,120	$3,229,926	-27.6%
2020 (projected)	$2,540,451	$3,344,163	-27.5%
2021 (projected)	$2,643,498	$3,462,904	-27.0%
2022 (projected)	$2,744,777	$3,586,170	-26.7%
Average % Difference			
2014-2016			**-21.8%**
2020-2022			**-27.1%**

Figure 2 Hydro One's Cost Performance 2004-2022

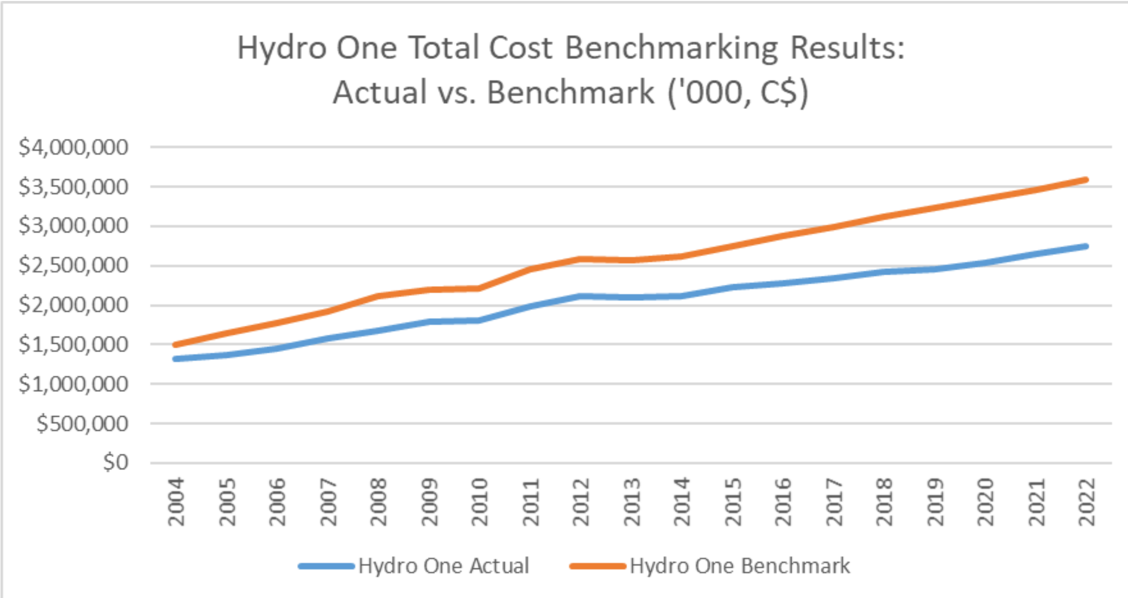


Table 2 and Figure 2 show that Hydro One's total costs have been below the benchmark value since 2004. In 2016, Hydro One is approximately $600 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to around $840 million by 2022, assuming Hydro One's application is approved in full. Throughout the 2020-2022 CIR period, Hydro One's projected total costs are 27.1% below benchmark expectations.

1.3 TFP Findings: Industry and Hydro One

Using a sample of 48 transmission utilities, PSE calculated the total factor productivity trend of the industry from 2004 to 2016. This twelve-year period showed an average annual decline in industry-wide TFP, with an annual growth rate of -1.45%.

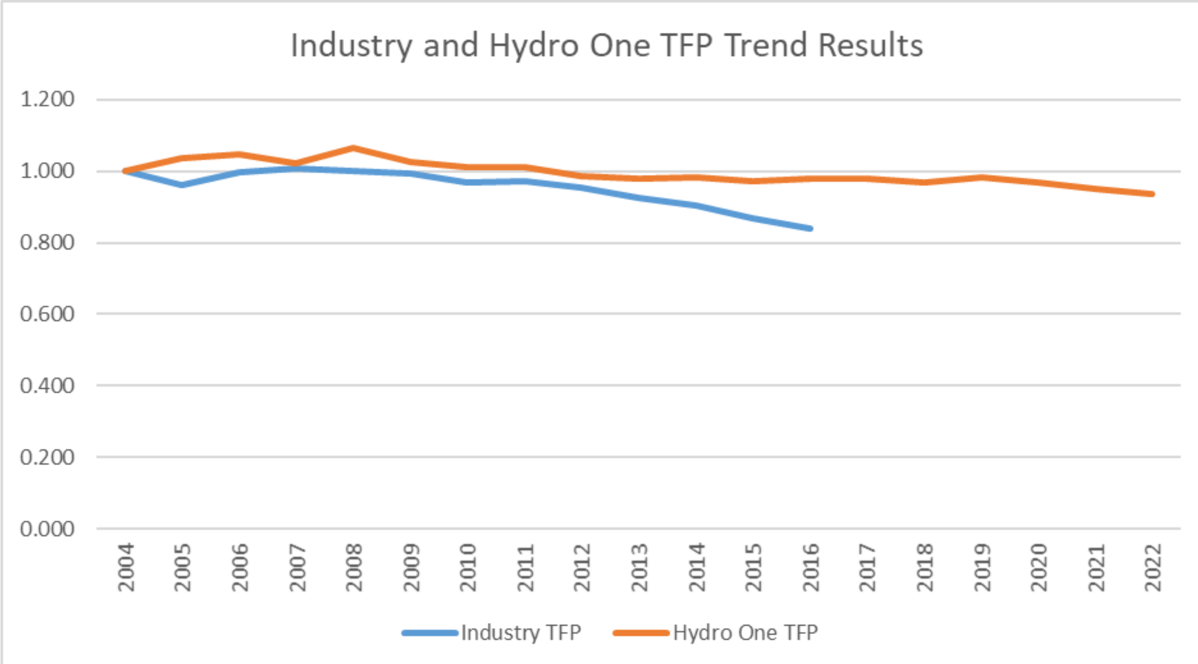
Hydro One's own TFP from the 2004 to 2016 period declined, but at a much slower pace than the industry, with an average annual growth rate of -0.18%. Hydro One's TFP is projected to decrease during the CIR period of 2020 to 2022, with an average annual growth rate of -1.70%.

The TFP results and average annual growth rates are provided in the table and figure following.

Table 3 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.960	1.038
2006	0.995	1.047
2007	1.006	1.022
2008	1.000	1.064
2009	0.994	1.025
2010	0.970	1.012
2011	0.972	1.012
2012	0.955	0.988
2013	0.926	0.978
2014	0.903	0.983
2015	0.869	0.971
2016	0.840	0.979
2017 (projected)	NA	0.978
2018 (projected)	NA	0.968
2019 (projected)	NA	0.982
2020 (projected)	NA	0.968
2021 (projected)	NA	0.951
2022 (projected)	NA	0.936
Average Annual Growth Rate		
2004-2016	**-1.45%**	**-0.18%**
2010-2016	**-2.39%**	**-0.56%**
2020-2022	**NA**	**-1.70%**

Figure 3 Industry TFP and Hydro One TFP



Hydro One's long-term TFP trend compares favorably to the industry trend. Hydro One's annual TFP trend is 1.27% higher than the industry TFP trend from 2004 to 2016. The industry has had a consistent decline in TFP since 2004. In Section 6.1, we address some possible causes for negative TFP growth.

1.4 PSE CIR Parameter Recommendations

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

The specific parameter values for each component are as follows:

- PSE recommends a two-factor **inflation factor** comprised of input weights of 14% labour and 86% non-labour. In 4GIR for the electric distribution industry, the inflation factor grows by 30% of the growth in Average Weekly Earnings (AWE) for Ontario, and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. However, this 4GIR weighting needs to be updated for transmission operations. With the transmission weighting of 14% and 86%, historically the inflation factor would grow a bit slower than under the distribution 4GIR weights.

- The PSE **X factor** recommendation is 0.0%. This is based on the negative industry TFP finding of -1.45%. While a negative X factor could be considered, the 4GIR Decision made clear the Board did not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR. However, the difference between the industry TFP trend and the X factor should be considered as an "implicit stretch factor". In other words, Hydro One will be expected or "stretched" to outpace the industry's historical TFP by 1.45%. This would be an extraordinarily large stretch factor value.

- The PSE **stretch factor** recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.45%, which is due to the X factor being set at 0.0%. The second reason is the total cost benchmarking result that shows Hydro One is 27.1% below its benchmark costs throughout the CIR period. PSE notes that in 4GIR a benchmark finding of -25% or less would imply a 0.0% stretch factor. Hydro One's score of -27.1% meets this standard. Given the strong cost performance and the large implicit stretch factor, PSE believes a stretch factor of 0.0% is warranted.

- PSE recommends not including an **output growth factor** to simplify the revenue cap formula. While mathematically an output growth factor should be included within the formula (as we will show in Section 2), the measured outputs in this study are unlikely to measurably grow during the CIR period. The output factor would be very close to 0.0% for every year. Additionally, the inclusion of the capital factor to the formula should capture the expected capital cost impact of output growth.

- The **capital factor** is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending. As is seen in those evaluations, the proposed capital spending by Hydro One compares favorably to the industry. The TFP trend during the CIR period continues to exceed the historic TFP trend of the industry, and Hydro One's projected total costs are 27.1% below its benchmark values throughout the CIR period.

The methodology used to arrive at Equation 1 is shown in the following section.

2 The Revenue Escalation Formula

Since so much of this study ultimately relates to the custom IR process, a brief overview of the mathematics underlying the general revenue escalation formula is warranted. This section gives a general equation for a generic revenue escalation formula and explains how this formula was determined. Subsequent sections discuss total cost benchmarking (Sections 3 and 5) and TFP research (Sections 4 and 6), and the results for those sections are used in CIR recommendations.

2.1 Derivation of the Formula

In the previous section, we recommended the following equation as the general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

This section shows how Equation 1 was determined.

The allowed revenue escalation within the revenue escalation formula should mimic the expected growth in costs. Production theory postulates that there should be three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (O).

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 2]}$$

The mathematical derivation of Equation 2 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Revenue = Growth\ Cost \qquad \text{[Equation 3]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

$$Growth\ Cost = I + Growth\ \mathrm{Q} \qquad \text{[Equation 4]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (O) to Equation 4 to develop Equation 5 below.

$$Growth\ Cost = I + Growth\ Q + O\ - O \qquad \text{[Equation 5]}$$

As we will further discuss in Section 4 on the TFP methodology, the TFP trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = O - Growth\ Q \qquad \text{[Equation 6]}$$

We can rearrange the terms in Equation 5 to the following equation.

$$Growth\ Cost = I - (O - Growth\ Q) + O \qquad \text{[Equation 7]}$$

And then insert Equation 6 into Equation 7.

$$Growth\ Cost = I - TFP\ trend + O \qquad \text{[Equation 8]}$$

The last step in getting to Equation 2 is to insert Equation 3, redefine the TFP trend and call it X.

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 9]}$$

A "stretch factor" is sometimes added to the escalation formula to challenge (or stretch) the utility to achieve TFP gains above and beyond the industry TFP expectation. A positive stretch factor slows allowed revenue growth in a manner that shares with customers the financial benefits of the utility exceeding the industry TFP trend. Within 4GIR, the stretch factor is informed by econometric total cost benchmarking evidence, because an inefficient firm can more easily cut costs and ramp up TFP trends than an efficient utility can.

Once we insert the stretch factor (SF) term, we have the following equation.

$$Growth\ Revenue = I - X - SF + O \qquad \text{[Equation 10]}$$

As stated in Section 1.4 the output growth factor (*Growth O*) will be close to zero every year (see Table 8). For example, average annual growth rates from 2020 to 2022 of KM of Line, Maximum Peak Demand, and Output Quantity Index are 0.02%, 0.00%, and 0.01%, respectively. Furthermore, the existence of a Capital Factor should capture the anticipated capital cost impacts of output growth. Thus, if we drop the output term from the equation we get:

$$Growth\ Revenue = I - X - SF \qquad \text{[Equation 11]}$$

Hydro One is proposing to add a Capital Factor term that accounts for additional capital spending. When this term is added, we arrive at the following equation, which was the recommendation in Section 1.4 .

$$Growth\ Revenue = I - X - SF + Capital\ Factor \qquad \text{[Equation 12]}$$

2.2 Discussion of the Specific Values of Each Term

2.2.1 Inflation Factor

The input price inflation index measures the annual external market increase in the price of inputs used within the operations of the utility. The inputs are labour and non-labour. In the 4GIR decision, the index used to measure labour inflation was the Average Weekly Earnings (AWE) for Ontario, published by Stats Canada. The index used to measure non-labour was the Gross Domestic Product-Implicit Price Index, Final Domestic Demand (GDP-IPI FDD) for Canada.[9] For the distributors, the weighting in the 4GIR is 30% on AWE and 70% on GDP-IPI FDD. These two metrics are defined as follows:

1. **AWE:** Annual percentage change in average weekly earnings for all employees in Ontario (from Statistics Canada CANSIM Table 281-0027, available in early April). The annual percentage change will be from the year prior to two years prior.

2. **GDP-IPI:** Annual percentage change in the GDP-IPI FDD for Canada (from Statistics Canada CANSIM Table 380-0066). The annual percentage change will be from the year prior to two years prior.

For the transmission inflation factor, PSE recommends the exact same calculation procedures for the individual labour and non-labour indexes as implemented in the 4GIR distribution inflation formula, but with different weights. Based on the available evidence from the benchmarking sample, we recommend a 14% weighting on AWE and an 86% weighting on GDP-IPI FDD (see Section 7 for a description of how the 14% was calculated). The recommended inflation factor calculation is described as follows:

Inflation Factor = (0.14 * growth in AWE) + (0.86 * growth in GDP-IPI FDD)

2.2.2 X Factor

The X Factor should be based on an external measure of the industry TFP trend. The utility that it is being applied to should have no (or very little) impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's cost increases to the allowed revenue escalation. If a utility's own TFP is used within the formula, it will significantly weaken the incentives to enhance productivity and reduce costs.

The TFP industry trend from 2004 to 2016 is declining, with an average annual growth rate

[9] November 21, 2013, *EB-2010-0379 Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 11.

of -1.45%. This negative growth rate also declined in a more recent time frame, with a growth rate of -2.39% in the 2010 to 2016 period.

Given the negative productivity findings within the electric transmission industry, combined with the 4GIR decision that stated the Board's desire for a non-negative X Factor, PSE recommends a 0.0% X Factor.

However, we note that this recommendation of 0.0%, instead of -1.45%, implies that Hydro One will need to exceed the historic industry TFP trend by 1.45% during the CIR period in order to achieve the allowed rate of return implicit in the escalation formula. This difference should be thought of as an "implicit stretch factor".

X Factor = 0.0%

2.2.3 Stretch Factor

The stretch factor is an additional term inserted into revenue or price caps to "stretch" the utility into exceeding the industry expected productivity growth of the X factor. It provides ratepayers with an assurance that revenues will grow slower for them than the growth that would occur because of the historical industry productivity value. Often this stretch factor is set based on cost benchmarking studies that provide evidence of the cost efficiency levels of the utility. A utility found to be inefficient will have an easier time cutting costs and increasing its productivity than a more efficient utility.

The recommended X Factor of 0.0% is already considerably higher than the industry TFP trend. This challenging expectation of beating the industry TFP trend is coupled with the total cost benchmarking finding in this report, which finds Hydro One's transmission total costs are 27.1% below benchmarking expectations during the CIR period. In other words, the benchmarking result indicates that Hydro One's cost efficiency appears to be far better than that of the industry. For these two reasons, PSE recommends a stretch factor of 0.0% for Hydro One.

Stretch Factor = 0.0%

2.2.4 Growth in Output

The last term in the revenue escalation formula is the growth in output. This term is not included for price cap indexes, because output growth will automatically increase revenues; this is because a utility's revenues are prices multiplied by billing determinants. However, as we showed in the index formula at the beginning of this section, in a revenue cap context the output growth term should be considered.

However, it is likely that this output growth term will be very close to zero in the CIR period (see

Table 8). The flat or declining nature of peak demands, due to conservation and demand management (CDM) plans and energy efficiency technology gains, makes it very likely that the maximum peak demand will be flat. Further, the total kilometres (KM) of transmission lines are projected by Hydro One to remain very close to current levels. Thus, the output growth rate will be essentially zero for each year of the CIR period.

The existence of the capital factor is another reason we recommend not including the output growth factor in the formula. The capital factor incorporates any expected capital costs resulting from output growth. This makes including the output factor somewhat redundant when the capital factor is also present in the formula. However, PSE felt it was important to mention this output growth term in the discussion, for the sake of accuracy and completeness. In the case of a revenue cap formula where the output growth factor is not expected to be zero and a capital factor is not present, an output growth factor should be included in a revenue adjustment formula.

Output Growth = Not included in formula

3 Total Cost Benchmarking Process, Dataset, Variables, and Model Details

The purpose of PSE's benchmarking analysis is to benchmark Hydro One's historical and projected total transmission costs and provide a recommendation on the appropriate stretch factor to apply to Hydro One's incentive regulation application.[10] The benchmark analysis is done by comparing Hydro One's *actual* total cost values (or its projected costs) with the benchmarking model's *predicted* values.[11]

When conducting a benchmarking evaluation, PSE recommends the econometric approach instead of basic peer group comparisons, because in most cases the econometric benchmarking method is more accurate. The econometric benchmarking method has the following advantages:

(1) The ability to statistically test candidate variables,
(2) The ability to statistically test results,
(3) The capacity to include a relatively large number of variables in the analysis, and
(4) It does not require the researcher to subjectively choose a peer group.

When comparing actual cost values with benchmarked (predicted) values, we use the logarithmic percentage difference of Hydro One's actual or projected total costs and the predicted total costs.[12] A percentage difference finding below zero implies Hydro One's costs are below the benchmark level (i.e., a negative value implies that Hydro One's actual total costs are lower than expected).

$$\%\,Difference = Natural\ Log\ \left(\frac{Actual\ Total\ Cost}{Benchmark\ Total\ Cost}\right)$$

To arrive at the predicted (benchmarked) costs for a utility, PSE uses historical cost data from a U.S. dataset comprised of multiple utilities to create a model; this model relates cost to certain variables for the industry.

The process takes publicly available variable data for each utility in the dataset (such as KM of line, maximum peak demand, wage levels, etc.), and creates a model that in a sense describes the

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[10] Hereafter, when we use the term "costs" or "total costs," we are referring to transmission costs, unless otherwise stated.

[11] In this report we will use "predicted," "expected," or "benchmark" costs to refer to the econometric model's outputs for those metrics. Note that the word "predicted" could refer to historical costs (e.g. "the model predicted that an average utility with these specific operating characteristics would have had costs of $X in 2007, but actual costs in 2007 were $Y"). We will use "forecasted costs" or "projected costs" to refer to Hydro One's estimates of total costs in future years, in this case 2018-2022. Therefore, in future years, we are comparing the model's expected (predicted) costs with Hydro One's forecasted (projected) costs. Other variables/model input values such as "KM of transmission lines" may also have "projected" or "forecasted" values.

[12] We use the logarithmic percentage rather than the arithmetic percentage because it is the convention within the benchmarking industry and the method used in 4GIR.

industry (the "industry" in this case is comprised of the utilities in the dataset). This model can then be used to predict the expected costs for each utility for any given year, given the specific variable data for that utility.[13] For future years, projected values for Hydro One costs, and for other variables, are used in a similar manner.

The expected costs (benchmark costs) for a given utility represent the costs we would expect from that utility, given its specific variable data, if that utility were an "average" performer. Thus, for any utility in the dataset, actual or projected costs can be compared to expected costs, and this comparison can be made for any given year.[14] In this report, the model is used to produce Hydro One's "expected" (benchmarked) total transmission costs.

The general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as KM of transmission lines, average voltage of lines, maximum peak demand, wage levels, etc.
2. Using the historical data (and projected data for Hydro One), PSE estimated an econometric model that expresses the relationship between the variables and cost.
3. PSE can then produce "benchmark" values for a given utility. The benchmark values are determined from the model, using the specific variable values for a given year. In Hydro One's case, the benchmark represents the total cost amount expected for an average-performing utility with the same variable values faced by Hydro One.
4. We then compare the total costs that are <u>expected</u> (predicted) by the model to Hydro One's <u>actual</u> historical and projected costs, which allows us to: (1) evaluate the historical and projected cost performance, and (2) recommend a stretch factor. This process is performed for specific years; e.g. we can compare Hydro One's expected 2015 costs with its actual 2015 costs.

The process for future years is similar to the process for past years. Hydro One has total transmission cost projection estimates for 2018-2022. Those projected costs can be compared to the model's predicted costs for those years. Variable data for 2018-2022 is also projected (using Hydro One estimates or third-party sources).

[13] A complete list of variables used in the model appears later, in Section 3.2 below.

[14] Again, "projected" refers to Hydro One's estimates of what its actual costs will be from 2018-2022; "expected" refers to values that the model produces ("expected" values could refer to previous years or future years).

3.1 Summary of Dataset

3.1.1 Econometric Benchmarking Requires a Robust Dataset

Econometric benchmarking of Hydro One's transmission costs requires a robust dataset, with multiple transmission utilities, over multiple years, with publicly available information on annual explanatory variables and output. Furthermore, the definitions used in the variables and output should be consistent across all the utilities in the dataset. For example, the various sub-categories of transmission expenses should be similar across the utilities in the dataset; otherwise, we cannot be sure that utilities are classifying costs in the same manner.

Hydro One provides transmission service for most of Ontario, and so an Ontario-only dataset would mostly consist of Hydro One data. Therefore, an Ontario-only dataset would not be sufficient.

3.1.2 The Necessary Data is Not Available for Most Canadian Utilities

PSE investigated whether the dataset could include Canadian transmission utilities from other provinces. However, most other Canadian transmission utilities are not compelled to publicly file the information necessary to analyze consistently defined cost categories and consistently defined output and explanatory variables.

However, U.S. utilities are required to file FERC Form 1s that contain variable and output data defined in a consistent, standardized manner. The transmission cost, output, and variable data in FERC Form 1s must be maintained in accordance with the Uniform System of Accounts.[15]

PSE contacted nine Canadian transmission utilities and asked if they would be willing to participate in the benchmarking study. Participation in the study would have required that the utilities give PSE the type of cost information that was used in this report. None of the utilities wished to participate.

Due to the absence of publicly available Canadian data, unwillingness of utilities to participate voluntarily, and non-uniformity of cost categories in Canada even if the data were available, PSE does not use Canadian utilities in its dataset, other than Hydro One.

3.1.3 The PSE Dataset

The benchmarking sample includes 57 unique utilities with annual data from 2004 to 2016. The data begins in 2004. This is the first year that transmission peak demand is reported from SNL Energy's FERC Form 1 database. The total number of observations in the dataset is 732 (here an

[15] See, e.g., *Uniform System of Accounts*, at https://www.ferc.gov/enforcement/acct-matts/usofa.asp

"observation" means one utility's costs over one year, with the variable data for that year). For some utilities, certain individual years did not yield usable observations, due to incomplete or missing data. For this reason, PSE used an "unbalanced" panel dataset to include more utilities in the benchmarking sample. The number of observations is more than sufficient for the creation of a statistically robust total cost econometric model.

The list of utilities included in the benchmarking sample is provided in the following table.

Table 4 List of Utilities in Benchmarking Sample

List of Utilities in Benchmarking Sample

Company	Most Recent Peak Demand (MW)	Company	Most Recent Peak Demand (MW)
Alabama Power Company	12,328	Kansas Gas and Electric Company	2,604
ALLETE (Minnesota Power)	1,520	Kentucky Utilities Company	5,370
Arizona Public Service Company	7,906	Louisville Gas and Electric Company	2,989
Atlantic City Electric Company	2,673	Mississippi Power Company	2,692
Avista Corporation	2,310	Monongahela Power Company	2,053
Baltimore Gas and Electric Company	6,601	Nevada Power Company	6,996
Black Hills Power, Inc.	977	New York State Electric & Gas Corporation	2,967
Central Hudson Gas & Electric Corporation	1,088	Niagara Mohawk Power Corporation	8,578
Central Maine Power Company	1,550	Northern States Power Company - MN	10,357
Cleco Power LLC	3,509	Oklahoma Gas and Electric Company	6,649
Commonwealth Edison Company	21,175	Orange and Rockland Utilities, Inc.	1,435
Connecticut Light and Power Company	6,087	PacifiCorp	18,583
Consolidated Edison Company of New York, Inc.	12,663	PECO Energy Company	8,364
Delmarva Power & Light Company	4,114	Potomac Electric Power Company	5,786
Duke Energy Carolinas, LLC	23,622	PPL Electric Utilities Corporation	7,216
Duke Energy Florida, LLC	12,082	Public Service Company of Colorado	7,604
Duke Energy Indiana, LLC	7,282	Public Service Company of New Hampshire	2,366
Duke Energy Ohio, Inc.	5,308	Public Service Electric and Gas Company	9,800
Duke Energy Progress, LLC	14,355	Rochester Gas and Electric Corporation	1,601
Duquesne Light Company	2,826	San Diego Gas & Electric Co.	4,343
El Paso Electric Company	1,877	South Carolina Electric & Gas Co.	5,266
Empire District Electric Company	1,114	Southern California Edison Company	23,687
Florida Power & Light Company	25,797	Southern Indiana Gas and Electric Company, Inc.	1,217
Gulf Power Company	2,752	Southwestern Public Service Company	6,003
Hydro One Transmission	**23,213**	Tampa Electric Company	4,453
Idaho Power Co.	4,359	Tucson Electric Power Company	4,356
Indianapolis Power & Light Company	2,670	Union Electric Company	7,768
Jersey Central Power & Light Company	5,955	West Penn Power Company	3,954
Kansas City Power & Light Company	3,714		
Sample Average Peak =	**6,956**		
Number of Utilities =	**57**		

3.1.4 The Definition of "Costs"

Both OM&A and capital costs used in the benchmarking models for the U.S. transmission utilities are derived using FERC Form 1 filing data.[16] United States investor-owned utilities are required

[16] All FERC data was downloaded by PSE from SNL Energy's database tool.

to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing, administrative and general). Form 1s also include information regarding “plant in service” and accumulated depreciation that is used in constructing capital costs.

PSE used a definition of “cost” for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the cost definition for the U.S. sample. Subtracting “transmission of electricity by others” expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not subtracted, would create an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. PSE also subtracted pensions and benefit expenses from the cost definition. Given the different healthcare structures between Canada and the U.S., this expense category could slightly inflate U.S. costs relative to Hydro One.

The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).[17] Some of the U.S. utilities own and operate power plants and/or conduct distribution functions. We allocated A&G expenses for those utilities based on the ratio of transmission expenses (minus transmission of electricity by others) to the total expenses of the utility minus the expenses of fuel, purchased power, transmission of electricity by others, and A&G expenses. Similarly, general capital costs are allocated for the U.S. sample by the ratio of transmission gross plant in service to total plant in service minus general and intangible plant in service.

3.2 Variables in the Benchmarking Model

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility “produces”). Business condition variables quantify the factors that drive costs in a particular service territory, such as terrain, input prices, and average voltage of transmission line. Variables such as “average voltage of transmission line” are business condition variables because they are, in large part, not up to the utility—service territory and electricity demand concentration (among other factors) dictate what transmission voltages are needed.

The output variables used in the total cost econometric benchmarking research are:

- Total kilometres of transmission line, and
- Maximum peak demand.

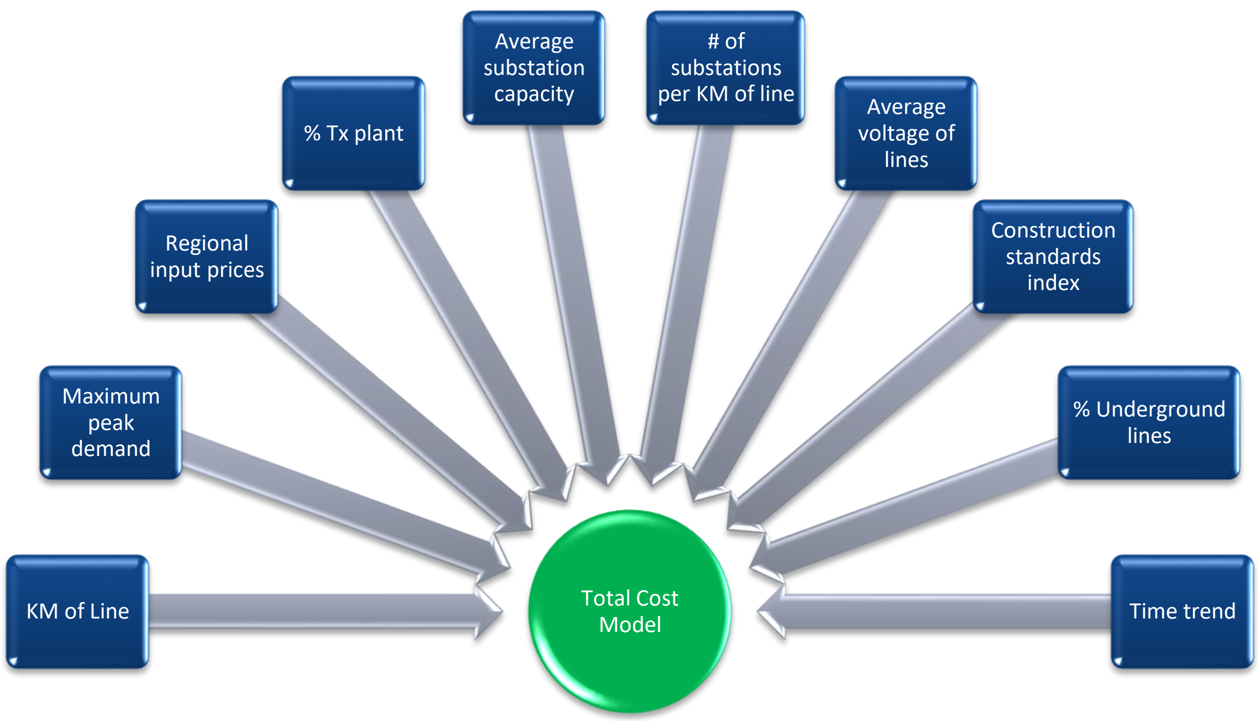
The business condition variables used in the total cost econometric benchmarking research are:

[17] The A&G expenses are after pensions and benefits expenses are subtracted.

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission plant in total electric utility plant,
- Average capacity in MVA per transmission substation,
- Number of transmission substations per kilometre of transmission line,
- Average voltage of transmission lines,
- Construction standards index for building a transmission pole,
- Percent of lines that are underground, and
- A time trend variable.

The variables included in the benchmark analysis are shown in the figure below.

Figure 4 Variables in Econometric Cost Model



The list of variables incorporated into the econometric model is extensive. These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All variables are statistically significant at a 99% confidence level, and all variables are correctly signed (i.e. they are signed the way we would expect).

3.2.1 Output Variables

The total cost model includes two **output variables**. The first is the total kilometres of transmission line, the second is the maximum peak demand for each utility during the sample period. The output variables are gathered from SNL Energy's database. The raw data was gathered by SNL Energy from FERC Form 1 filings. The historical output data for Hydro One comes directly from the company. The maximum peak demand variable is calculated based on taking the maximum annual peak demand on the system in the sample that has occurred up to that year. For example, for the 2005 observation, the variable is the highest annual peak demand for either 2004 or 2005. For the 2016 observation, the maximum peak demand is the highest annual peak that has occurred since 2004.[18]

3.2.2 Input Prices

Input prices are divided into two categories: capital and OM&A. The capital input price calculation (using the perpetual inventory capital cost method) is discussed in detail in Section 3.3 The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price: labour and non-labour.

The labour component is calculated by taking wage levels for numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics (BLS) estimates of job occupation weights in the *Electric Power Generation, Transmission, and Distribution Industry*. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from the 2011 Canadian census, using wage data for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency for the U.S. and Hydro One regarding labour input prices, and also puts the input price in terms of each country's currency.

The non-labour component of the OM&A input price uses the gross domestic product price index (US GDP-PI) for the U.S. utilities. The Ontario non-labour component uses the same US GDP-PI for each year, but adjusts for the purchasing power parity (PPP) index. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price, we weighted each index using a 38% labour and a 62% non-labour rate.[19] This was derived from the inflation factor research that examined the labour and non-labour components in transmission total costs. Using the capital and OM&A cost

[18] An adjustment was made for the three Southern Company utilities (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. These three utilities reported transmission peak demands on the FERC Form 1 for the entire Southern Company system rather than at the individual operating company level. We proportioned out the reported Southern Company transmission peak demand reported on p. 400 of the FERC Form 1 by the reported system peak data of each operating company reported on p. 401 of the FERC Form 1.

[19] Note: this weighting is a different weighting than the one described in Section 1.1.3 and Section 2.2.1. The weighting in this section (38% labour/62% non-labour) applies to OM&A costs, which are more labor-intensive and have a larger labour component. The weighting recommended in previous sections (14% labour/86% non-labour) applies to **total** costs.

shares, PSE calculated a total input price index.

Total cost is divided by this comprehensive input price to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. That is, as the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all a utility's purchases (including labour) increase by 10%, its costs would also increase by 10%. This is derived from production theory, which states that costs equal input quantity multiplied by input price.

3.2.3 Business Condition Variables: Other

Beyond the two output variables and the input price index, there are six additional business condition variables included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of transmission plant in total electric plant** uses gross plant in service information from FERC Form 1s.[20] The variable measures the ability for a transmission utility to reduce costs through economies of scope: if the utility is also a generation and/or distribution utility, there may be cost savings to the transmission utility because of this added scope. The coefficient on the variable is expected to be positive: the higher the percentage of transmission plant in total electric plant, the higher we would expect total costs to be.

The **average substation capacity** variable is measured in MVA. The variable measures the average capacity per transmission substation reported on each utility's FERC Form 1 for each year. For Hydro One the assets were reported directly to PSE. We would expect that costs would increase as the average capacity per substation increases.

The **number of transmission substations per KM of transmission line** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to PSE by Hydro One. We would expect a positive correlation between: (1) the number of transmission substations per KM of transmission line, and (2) total costs.

The **average voltage of transmission lines** measures the differences in voltage levels across transmission systems. This variable is constructed by calculating a weighted average by length of the different voltage levels found on each utility's transmission system. Serving higher voltages will be more costly than serving lower voltages, *ceteris paribus*. Therefore, we would expect a

[20] All FERC Form 1 data was gathered by PSE using SNL Energy's Excel extraction tool. The exception is the data on pages 422 to 427 of the FERC Form 1s. This data includes all data dealing with substations and details of the transmission lines. PSE gathered and processed this data manually because SNL does not provide the details necessary for variable construction.

positive coefficient.

The **construction standards index (or loading)** variable measures the minimum requirements for strength of transmission structures, which vary by geographic region. Transmission lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware.

The loading variable is a way to quantify the expense associated with transmission line construction based on local weather conditions and the resultant regulatory requirements. This is accomplished by evaluating the percentage of strength capacity utilized under required load cases for a base transmission structure in different regions. The process and reasoning behind this variable are included in Appendix A. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

The **percentage of underground lines** measures the percentage of underground transmission lines to total transmission lines. Constructing underground transmission lines is far costlier than constructing overhead transmission lines. As the percentage of underground lines increases, we would expect total costs to increase: i.e., we expect a positive correlation between the percentage of underground lines and total costs.

The **time trend** variable captures a general industry total cost level trend over the studied period. The time trend could reflect industry trends or influences that are not captured by the current variables (or perhaps not even captured by any possible variables). Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. A similar variable was included in the 4GIR benchmarking models. In the present study, the variable is calculated by taking the current year of the observation and subtracting 2,003. For observations in the year 2004, the time trend variable equals 1. In 2014, the variable equals 11 (2,014 – 2,003). The coefficient value shows how adding an additional year increases or decreases total costs. If the industry is experiencing positive productivity trends during the sample period, the coefficient value will likely be negative. That is, as each year passes we expect <u>real</u> costs to be decreasing, assuming all other variables remain constant. If productivity is negative, we would expect a positive coefficient sign.

3.2.4 Projected Variable Values for Hydro One

For the years 2018-2022, projected values were used for Hydro One's variables.[21]

[21] Hydro One 2017 actual capital and OM&A costs were available and used for the study. The asset information on substations, lines, transformers, and voltages use 2017 projections as the actuals were not yet available at the completion of the research.

Input prices are calculated using the same procedures as the historical data, but with inflation projections for 2018-2022.[22] Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour OM&A component is based on the Conference Board of Canada's projections for the GDP-IPI. The projections range from 1.8% in 2018 to 1.9% in 2022. The labour component uses the Conference Board of Canada's projections for average weekly earnings in Ontario. This ranges from 3.1% in 2018 to 2.3% in 2022. The capital category is set to increase using the Conference Board of Canada's projections for engineering structures, electric power generation, transmission, and distribution. This ranges from 2.3% in 2018 to 2.2% in 2022.

The plant additions for 2018-2022 are based on Hydro One projections. OM&A cost projections are set based on Hydro One projections for 2020, and then escalate by 1.98% per year from the 2020 value. This 1.98% figure is based on the inflation factor recommended weighting of 14% (labour) and 86% (non-labour) using the Conference Board of Canada's projections for Average Weekly Earnings in Ontario (labour component) and their GDP-IPI projections (non-labour component) minus the X factor and stretch factor, which are set at 0.0% each. See Section 2.2.1 for how the 14%/86% weights were determined.

The **percentage of transmission plant in total electric plant** projections are based on the historic variable value for Hydro One.

The **average substation capacity** projections are based on asset projections provided to PSE by Hydro One.

The **number of transmission substations per KM of transmission line** projections are based on asset projections provided to PSE by Hydro One.

The projections for **average voltage of transmission lines** are based on asset projections provided to PSE by Hydro One.

The projections for **percentage of underground lines** are based on asset projections provided to PSE by Hydro One.

The **construction standards index** variable is set to the same value throughout all historical and projected years for Hydro One.

3.3 Perpetual Inventory Capital Cost Method

This report evaluates Hydro One's capital costs as a component of the total cost definition. PSE's measure of capital cost is based on a service price approach. This approach has a solid basis in

[22] Input price data for 2017 was available and used in the 2017 observation for Hydro One.

economic theory, and is the same method used in the 4GIR research and PSE's research in Hydro One's distribution CIR application.[23] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period t is the product of indexes of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period t, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using data on the value of net transmission utility plant in a benchmark year, and on gross transmission plant additions in subsequent years. It also uses an assumption about service lives. We use 1989 as the benchmark year in the current study for all U.S. utilities. We use 2002 as the benchmark year for Hydro One. This is the first feasible year to use for Hydro One, due to lack of data availability in years prior to 2002.

Hydro One provided PSE with their net transmission plant and their transmission plant additions. These included an allocation for general plant. For the U.S. sample, PSE allocated a portion of net plant and general plant additions based on the ratio of transmission gross plant in service to total gross plant in service minus general and intangible plant.

Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 1989 or 2002. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. This method is used both for Hydro One and the U.S. utilities. The formulas for the capital quantity index in 2002 and in subsequent years are provided below.[24]

$$XK^i_{2002} = \frac{Net\ Plant^i_{2002}}{TWA^i_{2002}}$$

$$XK^i_t = XK^i_{t-1} * d + \frac{Add^i_t}{WKA^i_t}$$

[23] See Hall and Jorgensen (1967) for a discussion of the use of service price methods for measuring capital cost.

[24] For the U.S. utilities the formulas begin in 1989.

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all transmission utilities provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the value of 3.59% for this parameter, based on Hydro One's 2015 Depreciation Rate Study and the U.S. Bureau of Economic Analysis (BEA) declining balance rate of 1.65 for electrical transmission, distribution, and industrial apparatus.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power transmission. We compute this index using data on differences in the cost of constructing utility plants between regions, and within regions over time. In particular for U.S. transmitters, we use the Handy-Whitman indexes for total power transmission plants, which vary over time and across six geographic regions. For Hydro One, we used the Handy-Whitman index for the North Atlantic region and adjusted for the Canadian PPP.

We determined the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*. These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for both U.S. and Hydro One. The index is already adjusted for currency differences between the two countries.

3.4 Translog Cost Function

Section 3.2 above listed the variables used to benchmark transmission costs. These variables were all evaluated to quantify their effect on transmission costs. As a starting point for evaluating variables, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers" (i.e., the variables), can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

A note on terminology: We use the term "estimated" to refer to the process by which the cost function is created. As the term "estimated" implies, the resultant model is not an exact function that describes every single possible variable/output and their effect on cost with 100% certainty. Some variables will remain unknown, and some variables could have associated data that is not practically available; furthermore, even a "true" model, if such a thing exists, would have an error term that reflects random variation. Thus when we "estimate" a model, it reflects the mathematical relationship between cost and cost drivers/outputs; this relationship is based on the dataset used, the variables and outputs used, the definition of "cost," and the specified procedure and assumptions for creating the model.

In general, cost is assumed to be a function of input prices, the output produced by the firm, and other independent variables that affect cost but are outside management's control. While a function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = (\beta_o * V_0) + (\beta_1 * Y) + \varepsilon$$

In this equation, the terms C and Y, denote cost and output, respectively. The beta (β) terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost. For example, the variable V_0 is multiplied by its associated parameter β_0, which indicates the magnitude of the effect of V_0 on cost. Each explanatory variable will have an associated β magnitude. The error term ε captures random noise. The error term is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can consist of different types of observations, as follows:

- Data from a single utility with multiple time observations (time series data),
- Data from many utilities observed at a single time period (cross-sectional data), or
- Data from many utilities with multiple time observations (cross-sectional time-series or panel data).

The procedure used to estimate model parameters is affected by the type of data used to determine the model. In our present study, we have a panel dataset with cost data from multiple utilities.

3.4.1 Statistical Tests

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is “the explanatory variable in question has no statistically significant effect on cost”. This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By “plausibly signed” we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would “expect” to see costs rise as the maximum peak demand served increases (i.e. the maximum peak demand parameter would be positively signed).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark.

If a given utility’s actual cost is below the benchmark cost, its cost performance is better than average—it spent less than did an average hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

3.4.2 Model Specification

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to “explain” movement in the dependent (often called the left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues cause the coefficient values to be biased. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the statements about precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weighting the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation focus the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[25] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[26] The computer software calculates information crucial to understanding whether each relationship as described by each coefficient can be supported statistically. These statistical claims are usually reported as either t-ratios or probability values.[27]

3.5 Total Cost Econometric Model

The econometric model parameter estimates along with t-statistics are provided in the table below. All first-order variables exceed the standard threshold of a significance level of 90% (t-stat greater than 1.645). In fact, all variables exceed a 99% statistical significance threshold (t-stat greater than 2.567). The adjusted R-squared value of the model is 0.923. All variables are correctly signed according to a priori engineering theory.

[25] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[26] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

[27] See Wooldridge, J. *Introductory Econometrics, 4th Edition*, pp. 122.

Table 5 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.359	18.840	CS	0.240	6.100
KM*KM	0.120	4.670			
KM*D	-0.378	-5.370	UG	0.885	3.650
D	0.622	20.960	Trend	0.012	5.290
D*D	0.362	13.670			
			Constant	11.650	116.880
Tx	0.513	16.460			
			Adjusted R-Squared	0.923	
Cap	0.144	6.810			
			Sample Period:		2004-2022
Sub	0.104	7.300	Number of Observations		732
Volt	0.214	10.050			

4 TFP Index Methodology

In the context of electric utilities, productivity is the quantity of output produced by the utility divided by the input quantity expended by the utility. The output quantity index measures the level of output provided by the utility. The input quantity index measures the level of resources used. PSE uses indexing techniques to capture outputs and inputs, which are in turn used to create a productivity term. We then examine how this productivity ratio changes over time to determine the productivity index trend.

The input quantity index consists of economic resources, such as OM&A labour, OM&A materials, and capital stock. The output quantity index in this study includes: (1) kilometers of transmission lines, and (2) maximum peak demand. These two outputs are combined into one output index using cost elasticity weights derived from the total cost econometric model.

The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

TFP trend measurement differs from total cost benchmarking; in the latter, utilities are compared relative to the average efficiency level of other utilities within the industry. TFP measures how productivity is changing over time for that same industry or utility. TFP does not, however, provide a comparative efficiency assessment to other utilities within the industry, because we have no context for the relative efficiency level of the individual utilities. However, TFP research, when combined with total cost benchmarking (as is the case in this report), can provide that context.

4.1 TFP Sample

The sample period for the TFP research begins in 2004 and ends in 2016. We also provided projected TFP results for Hydro One through 2022. 2004 is the first viable year to begin the study, given the availability of peak demand values for the sample.

There are 48 utilities that comprise the TFP sample. The following table provides the list of utilities included in the TFP sample. This list is smaller than the one for the total cost benchmarking sample, because for the TFP analysis, utilities needed an observation in every single year of the sample period. In other words, we needed a balanced panel—we could not use any utility that had missing data in any one of the years 2004-2016. This contrasts with the benchmarking model, where a specific year for a specific utility can be omitted if that data is unavailable (while still using other years for that utility), resulting in an unbalanced panel estimation.

Table 6 Utilities in TFP Sample

List of Utilities in TFP Sample			
Company	Most Recent Peak Demand (MW)	Company	Most Recent Peak Demand (MW)
Alabama Power Company	12,328	Kentucky Utilities Company	5,370
ALLETE (Minnesota Power)	1,520	Louisville Gas and Electric Company	2,989
Arizona Public Service Company	7,906	Mississippi Power Company	2,692
Avista Corporation	2,310	Monongahela Power Company	2,053
Black Hills Power, Inc.	977	Nevada Power Company	6,996
Central Hudson Gas & Electric Corporation	1,088	New York State Electric & Gas Corporation	2,967
Cleco Power LLC	3,509	Northern States Power Company - MN	10,357
Commonwealth Edison Company	21,175	Oklahoma Gas and Electric Company	6,649
Connecticut Light and Power Company	6,087	PacifiCorp	18,583
Consolidated Edison Company of New York, Inc.	12,663	PECO Energy Company	8,364
Duke Energy Carolinas, LLC	23,622	Potomac Electric Power Company	5,786
Duke Energy Indiana, LLC	7,282	PPL Electric Utilities Corporation	7,216
Duke Energy Ohio, Inc.	5,308	Public Service Company of Colorado	7,604
Duke Energy Progress, LLC	14,355	Public Service Company of New Hampshire	2,366
Duquesne Light Company	2,826	Rochester Gas and Electric Corporation	1,601
El Paso Electric Company	1,877	San Diego Gas & Electric Co.	4,343
Empire District Electric Company	1,114	South Carolina Electric & Gas Co.	5,266
Florida Power & Light Company	25,797	Southern California Edison Company	23,687
Gulf Power Company	2,752	Southern Indiana Gas and Electric Company, Inc.	1,217
Hydro One Transmission	**23,213**	Southwestern Public Service Company	6,003
Idaho Power Co.	4,359	Tampa Electric Company	4,453
Indianapolis Power & Light Company	2,670	Tucson Electric Power Company	4,356
Kansas City Power & Light Company	3,714	Union Electric Company	7,768
Kansas Gas and Electric Company	2,604	West Penn Power Company	3,954
Sample Average Peak =	**7,160**		
Number of Utilities =	**48**		

4.2 Output Quantity Index

This section describes the TFP output quantity index calculations. PSE used the same definition of outputs for the TFP study as we did for the econometric total cost benchmarking study. There are two outputs: kilometers of transmission lines and maximum peak demand.

The two outputs need to be combined into one output quantity index. PSE accomplished this using output weights derived from the econometric total cost model. The weights are 36.6% and 63.4% for KM of line and maximum peak demand, respectively.

These two outputs are crucial components of transmission outputs. The main function of a transmission grid is to connect power supply with electric demand via distribution networks. The length of lines are constructed to connect generation with these distribution networks. Transmission systems are constructed not only to connect generation with distribution, but also to meet the electric demands of the end-use consumers. Systems are constructed to meet the maximum peak demands of these consumers.

4.2.1 Output Quantity Index Results

The two components of the output quantity index for the industry and Hydro One are provided in the following tables. After combining the components, the overall index is provided in the last column. The industry KM of line has grown by 0.49% per year over the full sample period. The industry's maximum peak demand grew at an annual rate of 1.50% over the full sample period. However, much of this growth was prior to 2009. Since 2010, the industry's maximum peak demand has only increased by 0.26% per year.[28] The overall output index grew by 1.13% per year during the full sample period, and by 0.38% per year since 2010.

Hydro One's outputs have grown at a considerably slower rate than those of the U.S. electric transmission industry. The company's KM of line and maximum peak demand have increased by 0.14% and 0.51% per year from 2004 to 2016, respectively. Hydro One's output quantity index grew by an average annual rate of 0.37% from 2004 to 2016. During the period of 2020 to 2022, both outputs are projected to essentially remain constant. We note that the maximum peak demand variable has been constant for Hydro One since 2006. The value is 27,005 MW. This is because all reported Hydro One peak demands subsequent to 2006 have been below 27,005 MW.

[28] Given the definition of the maximum peak demand variable, the growth rate has a floor of zero.

Table 7 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	269,938	322,074	1.000
2005	270,606	341,545	1.039
2006	271,519	352,957	1.062
2007	273,730	360,471	1.079
2008	274,995	373,230	1.105
2009	275,529	375,386	1.110
2010	276,661	379,747	1.120
2011	278,122	381,717	1.126
2012	281,442	381,872	1.131
2013	282,314	382,283	1.133
2014	284,859	383,462	1.139
2015	286,866	385,546	1.146
2016	286,274	385,812	1.145
Average Annual Growth Rate			
2004-2016	0.49%	1.50%	1.13%
2010-2016	0.57%	0.26%	0.38%

Table 8 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.017
2006	20,625	27,005	1.040
2007	20,624	27,005	1.040
2008	20,661	27,005	1.040
2009	20,658	27,005	1.040
2010	20,676	27,005	1.040
2011	20,694	27,005	1.041
2012	20,891	27,005	1.044
2013	20,904	27,005	1.045
2014	20,882	27,005	1.044
2015	20,948	27,005	1.045
2016	20,949	27,005	1.045
2017 (projected)	20,689	27,005	1.041
2018 (projected)	20,965	27,005	1.046
2019 (projected)	20,967	27,005	1.046
2020 (projected)	20,967	27,005	1.046
2021 (projected)	20,970	27,005	1.046
2022 (projected)	20,974	27,005	1.046
Average Annual Growth Rate			
2004-2016	0.14%	0.51%	0.37%
2010-2016	0.22%	0.00%	0.08%
2004-2018	0.12%	0.43%	0.32%
2020-2022	0.02%	0.00%	0.01%

4.3 Input Quantity Index

There are two components to the input quantity index: OM&A quantity and capital quantity. These two measures are then combined using Tornqvist indexes based on using the cost shares of each input component. Tornqvist indexes are a commonly used indexing methodology, and this is the same approach used in the 4GIR TFP research.

4.3.1 OM&A Quantity

The OM&A quantity used in the TFP calculation is derived by dividing annual OM&A expenses in year *t* by the OM&A input price index in year *t*.

$$OM\&A\ Quantity_t = \frac{OM\&A\ Expenses_t}{Input\ Price\ Index_t}$$

4.3.2 OM&A Cost and Input Price Definitions

PSE used the same cost and price definitions for both the TFP and the benchmarking research. Please see Section 3.1.4 and 3.2 for a description of both.

4.3.3 Capital Quantity: Perpetual Inventory Capital Method

PSE used the same procedures in both the benchmarking and productivity research for the capital quantity index. For a discussion on the capital quantity calculations, please see Section 3.3

4.3.4 Input Quantity Index Results

The input quantity index is provided in the tables following. The first table shows the industry capital quantity index, OM&A index, and then the combined input quantity index from 2004 to 2016. The second table shows the same results for Hydro One from 2004 to 2022. The industry's input quantities grew at a rapid pace over 2004 to 2016. This was especially true for the capital quantity index, which grew at an average annual rate of 2.61%. The OM&A quantity for the industry grew at a rate of 2.24% from 2004 to 2016.

The overall input quantity index for the industry grew at an annual rate of 2.58% from 2004 to 2016. This rate has accelerated since 2010, due to a ramp up in the capital quantity trend.

Hydro One's input quantities have grown at a much slower rate. This is the reason for Hydro One's higher productivity trend relative to the industry. Hydro One's capital quantity grew by 0.82% per year from 2004 to 2016, and the company's OM&A quantity declined from 2004 to 2016, with a growth rate of -0.84% per year. The overall input quantity index at Hydro One grew by 0.55% per year from 2004 to 2016. Over the period of 2020-2022, capital quantities are projected to grow by 1.94% per year, OM&A quantity is expected to grow by -0.10% per year, and the overall input quantity index is expected to grow by 1.70% per year. The growth rate in the overall input quantity index of Hydro One during the CIR period is far slower than the historical input quantity growth rates of the industry.

Table 9 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	819,018	2,294,607	1.000
2005	822,793	2,951,132	1.082
2006	831,662	2,751,414	1.067
2007	843,069	2,709,410	1.073
2008	862,388	2,841,232	1.105
2009	881,806	2,787,424	1.117
2010	908,558	2,908,991	1.155
2011	928,634	2,754,385	1.158
2012	957,230	2,747,615	1.184
2013	1,000,117	2,740,657	1.223
2014	1,045,506	2,692,799	1.261
2015	1,087,226	2,868,545	1.318
2016	1,120,167	3,002,205	1.363
Average Annual Growth Rate			
2004-2016	2.61%	2.24%	2.58%
2010-2016	3.49%	0.53%	2.76%

Table 10 Input Quantities for Hydro One

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	143,143	254,916	1.000
2005	142,603	234,820	0.980
2006	141,371	258,958	0.993
2007	141,803	286,106	1.017
2008	140,757	242,066	0.977
2009	142,618	278,926	1.015
2010	145,810	271,709	1.028
2011	147,863	256,117	1.028
2012	153,151	254,354	1.057
2013	154,007	263,559	1.069
2014	156,497	234,464	1.062
2015	156,324	256,381	1.077
2016	157,985	230,514	1.068
2017 (projected)	159,156	216,216	1.065
2018 (projected)	162,373	211,550	1.080
2019 (projected)	163,743	178,814	1.065
2020 (projected)	165,549	186,223	1.080
2021 (projected)	169,012	186,043	1.100
2022 (projected)	172,115	185,856	1.118
Average Annual Growth Rate			
2004-2016	0.82%	-0.84%	0.55%
2010-2016	1.34%	-2.74%	0.64%
2004-2018	0.90%	-1.33%	0.55%
2020-2022	1.94%	-0.10%	1.70%

5 Total Cost Benchmarking Results

Using a sample of 57 transmission utilities, PSE estimated a translog total cost econometric model. As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence.[29]

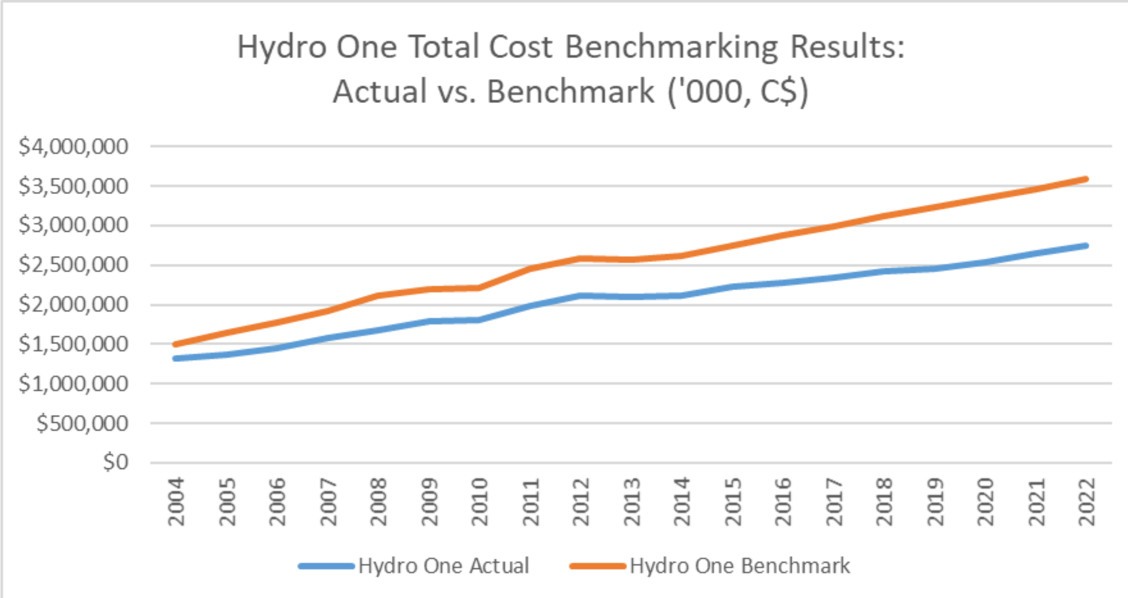
The benchmark scores are derived by calculating the logarithmic percentage between Hydro One's actual total costs and their model-predicted total costs. The model-predicted results are produced from a model that excludes Hydro One from the sample. This provides a truly external benchmark value to compare Hydro One's total costs against. A negative number implies that the company's actual costs are lower than the benchmark. The table following shows the scores for the historical and projected years.

[29] In fact, all first order variables in the model are statistically significant at the 99% confidence level.

Table 11 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,319,202	$1,500,514	-12.9%
2005	$1,372,128	$1,638,703	-17.8%
2006	$1,453,435	$1,773,126	-19.9%
2007	$1,586,919	$1,916,996	-18.9%
2008	$1,669,115	$2,108,130	-23.4%
2009	$1,783,173	$2,194,844	-20.8%
2010	$1,805,110	$2,206,257	-20.1%
2011	$1,984,174	$2,448,930	-21.0%
2012	$2,112,358	$2,584,997	-20.2%
2013	$2,097,031	$2,562,385	-20.0%
2014	$2,120,542	$2,620,081	-21.2%
2015	$2,227,713	$2,750,068	-21.1%
2016	$2,281,074	$2,876,130	-23.2%
2017 (projected)	$2,335,312	$2,995,513	-24.9%
2018 (projected)	$2,428,965	$3,118,802	-25.0%
2019 (projected)	$2,450,120	$3,229,926	-27.6%
2020 (projected)	$2,540,451	$3,344,163	-27.5%
2021 (projected)	$2,643,498	$3,462,904	-27.0%
2022 (projected)	$2,744,777	$3,586,170	-26.7%
Average % Difference			
2014-2016			**-21.8%**
2020-2022			**-27.1%**

Figure 5 Hydro One's Cost Performance 2004-2022



This table and graph illustrate Hydro One's total costs have consistently been below the benchmark value since 2004. In 2016, Hydro One is approximately $600 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to around $840 million by 2022. This assumes Hydro One's application is approved in full. Throughout the 2020-2022 period, Hydro One's projected total costs are approximately 27.1% below benchmark expectations.

6 Productivity Results

Productivity is defined as the ratio of an output quantity index to an input quantity index.

$$Productivity = \frac{Output\ Quantity\ Index}{Input\ Quantity\ Index}$$

The annual change in this index measures the TFP trend. The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

Using a sample of 48 transmission utilities, PSE calculated the TFP trend for the U.S. transmission industry from 2004 to 2016. Additionally, we calculated the TFP trend for Hydro One from 2004 to 2022.

The year over year results and average annual growth rates are provided in the table following.

Table 12 Industry and Hydro One TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate	Hydro One TFP Index	Hydro One TFP Growth Rate
2004	1.000		1.000	
2005	0.960	-4.1%	1.038	3.7%
2006	0.995	3.6%	1.047	0.8%
2007	1.006	1.1%	1.022	-2.4%
2008	1.000	-0.6%	1.064	4.0%
2009	0.994	-0.7%	1.025	-3.8%
2010	0.970	-2.4%	1.012	-1.2%
2011	0.972	0.3%	1.012	0.0%
2012	0.955	-1.8%	0.988	-2.4%
2013	0.926	-3.1%	0.978	-1.0%
2014	0.903	-2.5%	0.983	0.6%
2015	0.869	-3.9%	0.971	-1.3%
2016	0.840	-3.4%	0.979	0.8%
2017 (projected)	NA	NA	0.978	-0.1%
2018 (projected)	NA	NA	0.968	-0.9%
2019 (projected)	NA	NA	0.982	1.4%
2020 (projected)	NA	NA	0.968	-1.5%
2021 (projected)	NA	NA	0.951	-1.8%
2022 (projected)	NA	NA	0.936	-1.6%
Average Annual Growth Rate				
2004-2016	-1.45%		-0.18%	
2010-2016	-2.39%		-0.56%	
2004-2018	NA		-0.23%	
2020-2022	NA		-1.70%	

PSE calculated the total factor productivity trend for the industry from 2004 to 2016. This twelve-year period from 2004 to 2016 showed an average annual decline in industry TFP, with an annual growth rate of -1.45%. Since 2010, the industry TFP has declined at an even higher rate, with an average annual growth rate of -2.39%.

Hydro One's own TFP from the 2004 to 2016 period declined, with an average annual growth rate of -0.18%. From 2010 to 2016, Hydro One's TFP has declined, with an average annual growth rate of -0.56%. Hydro One's TFP is projected to decrease during the period of 2020 to 2022, with an average annual growth rate of -1.70%.

6.1 Interpretation of Negative TFP Growth

Changes in TFP will have tangible impacts on transmission utility costs and the value of electricity provided to end-use consumers. A negative industry TFP trend implies higher electricity costs for the industry (beyond inflationary cost increases). The OEB addressed this possibility in the Board's Decision dated November 21, 2013 in EB-2010-0379 (page 17):

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output.

TFP is a measure of the change in the outputs delivered by the utility (or industry) relative to the inputs required to deliver those outputs. However, it is important to note that a negative TFP growth rate does not <u>necessarily</u> indicate declining efficiency at either the industry or the utility level. Recall that the TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends indicate that measured outputs are growing slower than inputs.

While declining efficiency is certainly one possibility when observing negative TFP trends, there are several other possibilities. Systemic possibilities include:

1. The increasing of "outputs" that are not being measured within the TFP calculation. While PSE's output measure incorporated two key outputs of a transmission utility, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include reliability, safety, meeting increased regulatory requirements, increasing generation interconnections from wind or solar, providing enhanced environmental stewardship, and increasing other aspects of power quality.

2. External circumstances can change over time. One circumstance often found in modern western economies is slower growth. For some countries, output growth has slowed due to more energy efficient appliances and machinery, and conservation programs. This has slowed the growth in peak demands (in kW). Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP.

3. A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during that time, utilities needed to heavily invest in capital infrastructure to meet the higher peak demands (unlike the current situation, in the past utilities were able to fund much of this investment through increasing billing determinants rather than higher prices). At several utilities throughout North America, a high proportion of capital infrastructure is now past its useful life and needs replacement. However, capital expenditures may need to increase to replace this older infrastructure. Additionally, maintenance costs will also tend to increase as the grid

becomes older. The capital replacement expenditures and increasing maintenance costs will tend to cause a decline in TFP.

Unfortunately, it is impossible to empirically adjust for all the underlying causes of observed TFP trends. However, TFP measures are useful indicators of performance, assuming these other considerations are kept in mind.

7 Inflation Factor Research

In the Board's September 28, 2017 Decision for Hydro One Sault Ste. Marie, LLP (Hydro One SSM) regarding the company's application for electricity transmission, the Board stated that evidence on the appropriate input weights for the inflation factor should accompany future rate applications.[30] In the Hydro One SSM application, the company put forth the same input weights as were used for the distributors in 4GIR. The distributors' inflation factor has a 70% weight on non-labour and a 30% weight on labour. PSE was tasked with providing evidence for revising these weights to align with the electric transmission industry.

To accomplish this task, PSE started with the total cost benchmarking sample in this study. Using this sample, we gathered direct transmission salaries, administrative and general salaries, outside services employed, and electric construction salaries. We then allocated the transmission portion of the administrative and general salaries, outside services employed, and electric construction salaries and summed them with the direct transmission salaries to get a total labour cost for each observation in the benchmarking sample. We then divided this total labour cost by the total cost number in the benchmarking sample to get the labour percentage. This labour percentage was then averaged for the entire benchmarking sample.

The allocator used for administrative and general salaries and outside services employed is the same allocator as the one used in the TFP and benchmarking research to allocate all administrative and general expenses. The equation for the allocator is below.

$$Allocator^{OM\&A} = \frac{Tx\ Expenses - Tx\ of\ Electricity\ by\ Others\ Expenses}{Total\ Expenses - Fuel\ Expenses - Tx\ by\ Others - A\&G\ Expenses}$$

The allocator for the electric construction salaries is the portion of transmission plant additions for that year to total plant additions minus general plant additions. The equation is below.

$$Allocator^{capital} = \frac{Tx\ plant\ additions}{Total\ plant\ additions - General\ plant\ additions}$$

The full equation used to calculate the labour percentage in total costs is the following.

$$\frac{Tx\ Salaries + AG\ salaries * Allocator^{OM\&A} + Outside\ Services\ Employed * Allocator^{OM\&A} + Construction\ Salaries * Allocator^{Capital}}{Total\ Costs}$$

The average labour percentage for the entire benchmarking sample is 14%. The remaining costs (86%) are deemed to be non-labour costs.

[30] EB-2016-0356, Decision and Order dated September 28, 2017. Page 5.

8 PSE Recommendations

PSE used the results of this study to:

(1) Make recommendations regarding the CIR parameters that should be used in Hydro One's CIR application, and

(2) Assist the Board stakeholders in assessing the reasonableness of the cost levels contained in Hydro One's CIR application.

8.1 PSE's recommendations on CIR parameters

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch + Capital\ Factor$$

The specific parameter values for each component are as follows:

- PSE recommends an inflation factor calculated using the 4GIR calculation procedures, but with weights of 14% labour and 86% non-labour instead of the 4GIR weights. In 4GIR, the inflation factor is weighted with 30% of the growth in AWE for Ontario and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. PSE's recommendation for the electric transmission industry is to calculate the inflation factor with a 14% weight on AWE and an 86% weight on GDP-IPI FDD.

- The PSE X factor recommendation is 0.0%. This is based on the negative industry TFP finding of -1.45%. While a negative X factor could be considered, the 4GIR Decision made clear the Board does not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR.

- The PSE stretch factor recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.45%, which is due to the X factor being set at 0.0%. This "implicit stretch factor" is far higher than the 0.33% implicit stretch factor embedded in the 4GIR Decision. The second reason is the total cost benchmarking result that shows Hydro One will be 27.1% below its benchmark costs throughout the 2020-2022 CIR period. The 4GIR Decision would indicate a 0.0% stretch factor. PSE believes this strong cost performance warrants a 0.0% stretch factor.

- PSE recommends not including an output growth factor to simplify the revenue cap formula, since the expected growth rate is close to 0.0%, and due to the possible redundancy of including both an output growth factor and a capital factor.

- The capital factor is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending.

8.2 Reasonableness of Hydro One's Total Cost Levels

This study provides a total cost econometric benchmarking study and a TFP trend analysis of Hydro One's costs and productivity. These studies are conducted on both the historical outcomes and the outcomes projected by Hydro One. Both studies reveal Hydro One comparing favorably to the industry.

The graph below shows Hydro One's total cost benchmarking results for the historical time period (2004-2017) and the projected time period (2018-2022).

Figure 6 Hydro One Total Cost Benchmarking Results

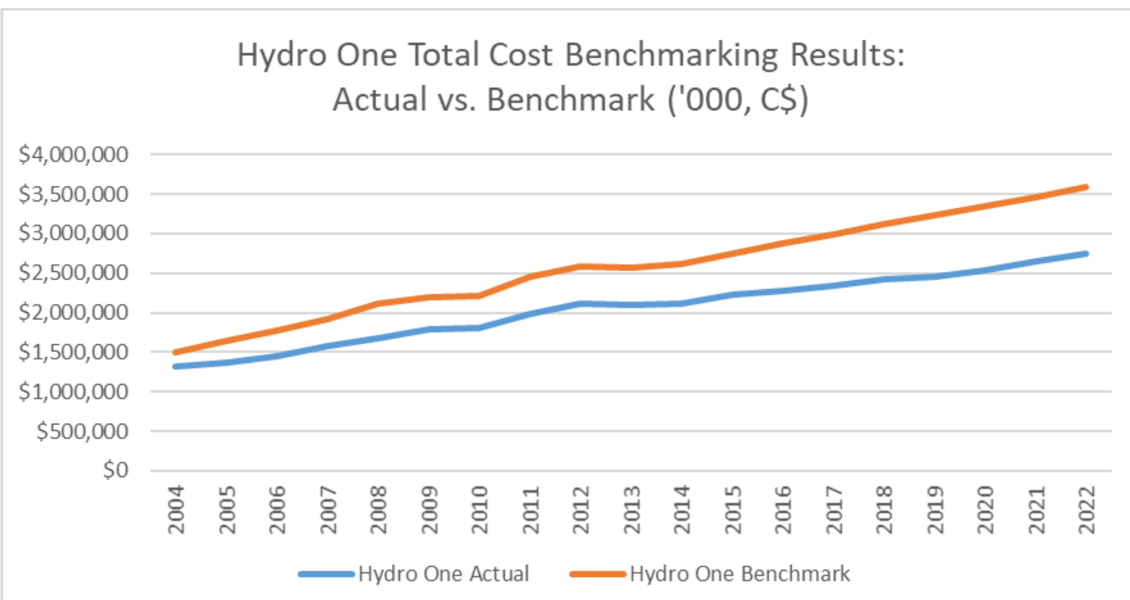
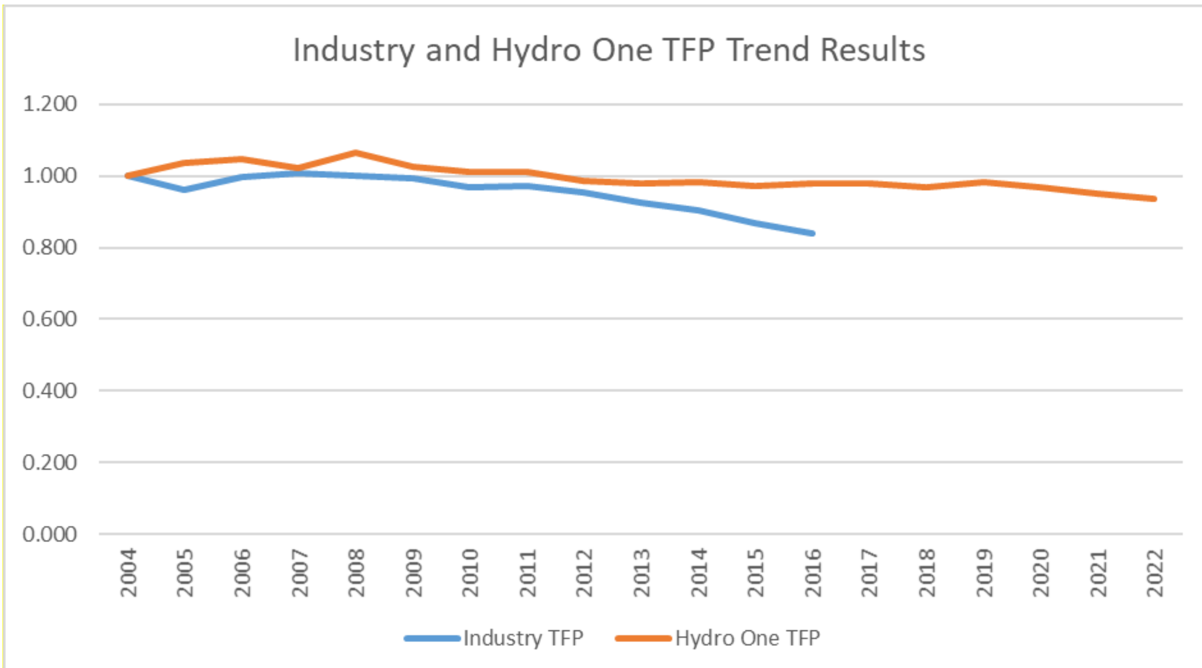


Figure 6 shows that Hydro One's total costs have consistently been below the benchmark value since 2004. In 2016, Hydro One is approximately $600 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to around $840 million by 2022. This assumes Hydro One's application is approved in full. Throughout the 2020-

2022 period, Hydro One's projected total costs are approximately 27.1% below benchmark expectations.

Hydro One's TFP results also indicate a utility whose TFP trend is higher than the industry's. Again, this is true both historically and into the future. The following figure contrasts the industry's TFP trend with Hydro One's.

Figure 7 Industry vs. Hydro One TFP



The industry's TFP has declined by 1.45% annually over the entire 2004 to 2016 period. This trend has accelerated in recent years. Since 2010, industry TFP has declined by 2.39% annually. Hydro One's TFP trend from 2004-2016 is -0.18% per year. Hydro One's projected TFP is expected to move lower, with a decline of 1.70% per year going forward to 2022.

9 Appendix A: Transmission Loading Variable

This Appendix explains the theory and data behind the transmission loading variable discussed in Section 3.2.3 (also known as the construction standards index). Per the Canadian Standards Association (CSA) and the National Electrical Safety Code (NESC), overhead transmission lines constructed throughout Ontario, Canada and the United States must withstand a minimum combination of accumulated ice and wind based on local extreme historical weather conditions. As a result, the required minimum design/build structural strength for an overhead transmission line is dependent on the physical location of the line.

This minimum structural strength requirement has a direct influence on the overall capital cost a utility must devote to its overhead transmission plant. For example, a transmission structure designed for harsher loading conditions is more expensive to construct because it may require larger diameter poles, greater setting or foundation depth, specialized insulators, and/or stronger hardware.

Furthermore, since these minimum strength requirements are developed from documented historical weather conditions, they provide an indirect indication of the severity of extreme ice and wind storms that overhead transmission lines are exposed to, which can influence operational and maintenance costs.

To account for the influence of CSA and NESC minimum overhead transmission line structure strength requirements and associated extreme weather conditions as they relate to total cost benchmarking, Power System Engineering's transmission line design engineers developed a related variable for statistical analysis. This was accomplished by evaluating the percentage of utilized strength capacity, under required CSA and NESC load cases, for a base transmission structure in different zones.

"Percentage of utilized strength capacity" is the percentage of the load resulting from specific design criteria (e.g., this line was designed to meet winds of X mph and ice of Y thickness) as a function of the overall maximum strength of the structure. The variable is a way to quantify the expense associated with transmission line construction based on local weather conditions. There were three main steps in developing the variable, as described below.

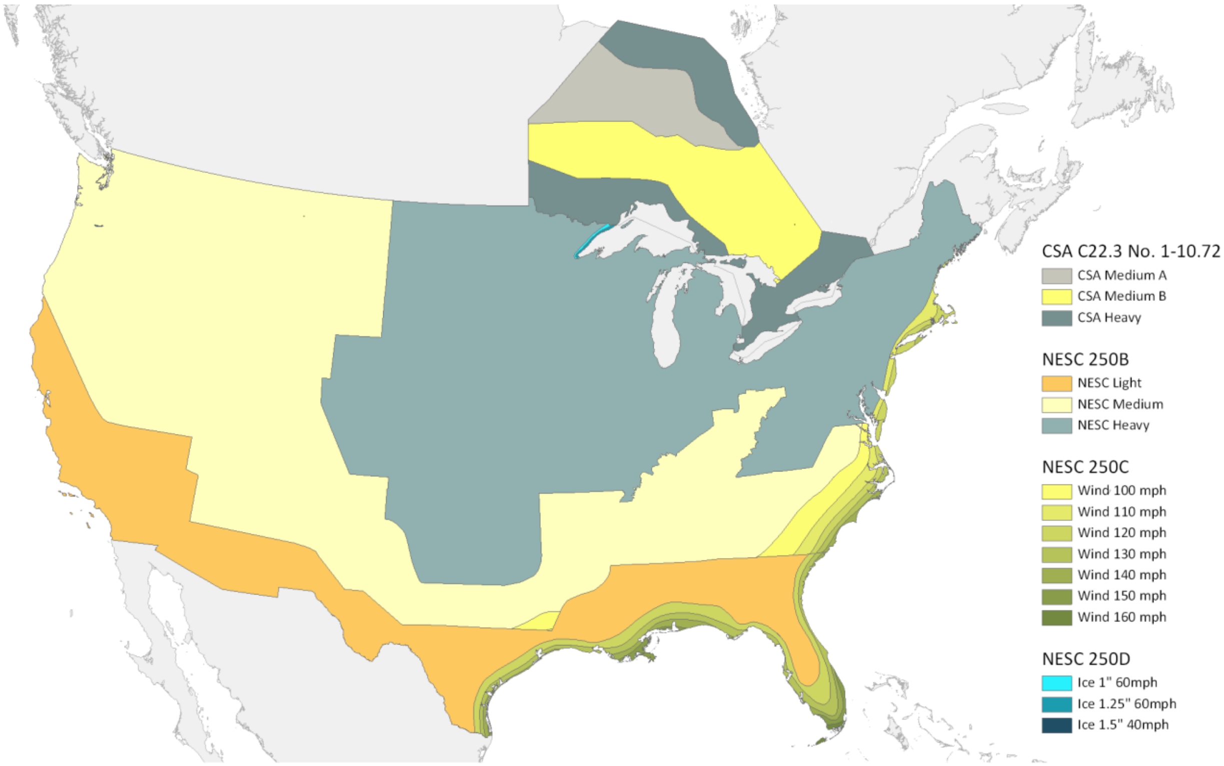
Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of transmission structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used.

The zone boundaries and the required ice and wind load cases are outlined in the Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10 for Canada, and the National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure 8.

Figure 8 CSA and NESC Loading Zones



Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

2. Loading capacity was evaluated for a base structure in each zone.

A base transmission structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table 13. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

Thus, Table 14 represents the loads as a percentage of the maximum allowable for the base transmission structure. For example, the design criteria for CSA 7.2 zone "Medium A" is 73.3% of the maximum load strength of the base structure described in Table 13. The design criteria required for a structure in CSA 7.2 zone "Severe" is 148.9% of the maximum load strength of the base structure described in Table 13, indicating that the base transmission structure would fail in those conditions.

Table 13 Base Transmission Structure Specifications

	Metric		English	
Pole Material	wood			
Pole Length	22.9	m	75	ft
Pole Class	H2			
Span Length	106.7	m	350	ft
Framing	TP-115			
Voltage	115 kV			
Construction Grade	NESC Grade B / CSA Grade 1			
Transmission Conductor Material	795 (26/7) ACSR			
Transmission Design Tension	6000	lb	26.7	kN
Shield Wire Material	3/8" EHS Steel			
Shield Wire Design Tension	2700	lb	12.0	kN

Industry best practice is to consider local historical weather data for transmission line designs, but the deterministic load cases defined by the CSA and NESC provide minimum requirements for each zone. Therefore, the load cases identified in CSA C22.3 No. 1-20 7.2 and NESC Rules 250B, 250C, and 250D were used for analysis. Loading zones with the same names in Canada and the United States are not equivalent, e.g. the CSA “Heavy” zone specifies different accumulated ice and wind loads than the NESC “Heavy” zone. Multipliers, including strength factors for structure components and load factors for ice and wind loads, are also specified in each code and were included in this analysis. PLS-CADD Lite, an engineering modeling software application for transmission and distribution structures, was used to complete nonlinear analysis of the base structure for each zonal load case, outlined in Table 14.

Table 14 Loading Capacity Usage Percentages by Loading Zone

CSA 7.2	**Zone**		**Loading [%]**
	Medium A		73.3
	Medium B		81.5
	Heavy		103.5
	Severe		148.9
NESC 250B	**Zone**		**Loading [%]**
	Light		75.3
	Medium		49.7
	Heavy		66.2
NESC 250C	**Wind [mph]**		**Loading [%]**
	85		43.1
	90		48.2
	100		59.1
	110		71.1
	120		84.1
	130		98.1
	140		113.1
	150		128.9
	160		145.5
NESC 250D	**Ice [in]**	**Wind [mph]**	**Loading [%]**
	1.5	30	33.7
	0.75	40	29.2
	1	40	36.2
	1.25	40	44.3
	1.5	40	53.7
	0.5	50	34.7
	0.75	50	43.9
	1	50	54.1
	0.5	60	48.9
	0.75	60	61.7
	1	60	75.9
	1.25	60	91.7

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2

3. Nonlinear loading models: PLS-CADD Lite Version 15.00
4. GIS mapping software: ArcGIS Pro v2.1, ArcGIS Server 10.5, SQL Server 2014
5. Utility service territories: S&P Global – Platts and Power System Engineering acquired service territories <https://www.platts.com/maps-geospatial>

PLS-CADD Lite Model Inputs

Zonal weather criteria are defined in NESC 250B and CSA 22.3 No. 1-10 7.2 and summarized in Table 15 below. The NESC set includes two additional sets of load cases which do not have counterparts in the CSA. These are Rule 250C: extreme wind loading and Rule 250D: extreme ice with concurrent wind loading. Separate zones were identified for these rules as well.

Table 15 Weather Criteria

		Wire Ice Density		Air Density Factor		Wind Pressure		Wire Ice Thickness		Ambient Temp		NESC Constant	
		[kg/m^3]	[lbs/ft^3]	[Pa/(m/s)^2]	[psf/mph^2]	[Pa]	[psf]	[mm]	[in]	[°C]	[°F]	[N/m]	[lb/ft]
NESC	Heavy	913	57.0	0.613	0.00256	190.5	4	12.7	0.5	-17.8	0	4.38	0.3
	Medium					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
	Light					428.6	9	0.0	0	-1.1	30	0.73	0.05
	Warm Islands (<9000 ft)					428.6	9	0.0	0	10.0	50	0.73	0.05
	Warm Islands (>9000 ft)					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
CSA	Severe	900	56.2	0.613	0.00256	400	8.40	19.0	0.75	-20	-4	N/A	
	Heavy					400	8.40	12.5	0.49	-20	-4		
	Medium A					400	8.40	6.5	0.26	-20	-4		
	Medium B					300	6.30	12.5	0.49	-20	-4		

Load factors and strength factors are summarized in Tables A2 and A3, respectively.

Table 16 Load Factors

	NESC Grade B	CSA Grade 1
Vertical	1.50	4.00
Tansverse - wind	2.50	2.00
Transverse - wire tensions	1.65	2.00
Longitudinal - at deadends (with terminations or tension changes)	1.65	2.00
Longitudinal - general (without terminations or tension changes)	1.10	1.30

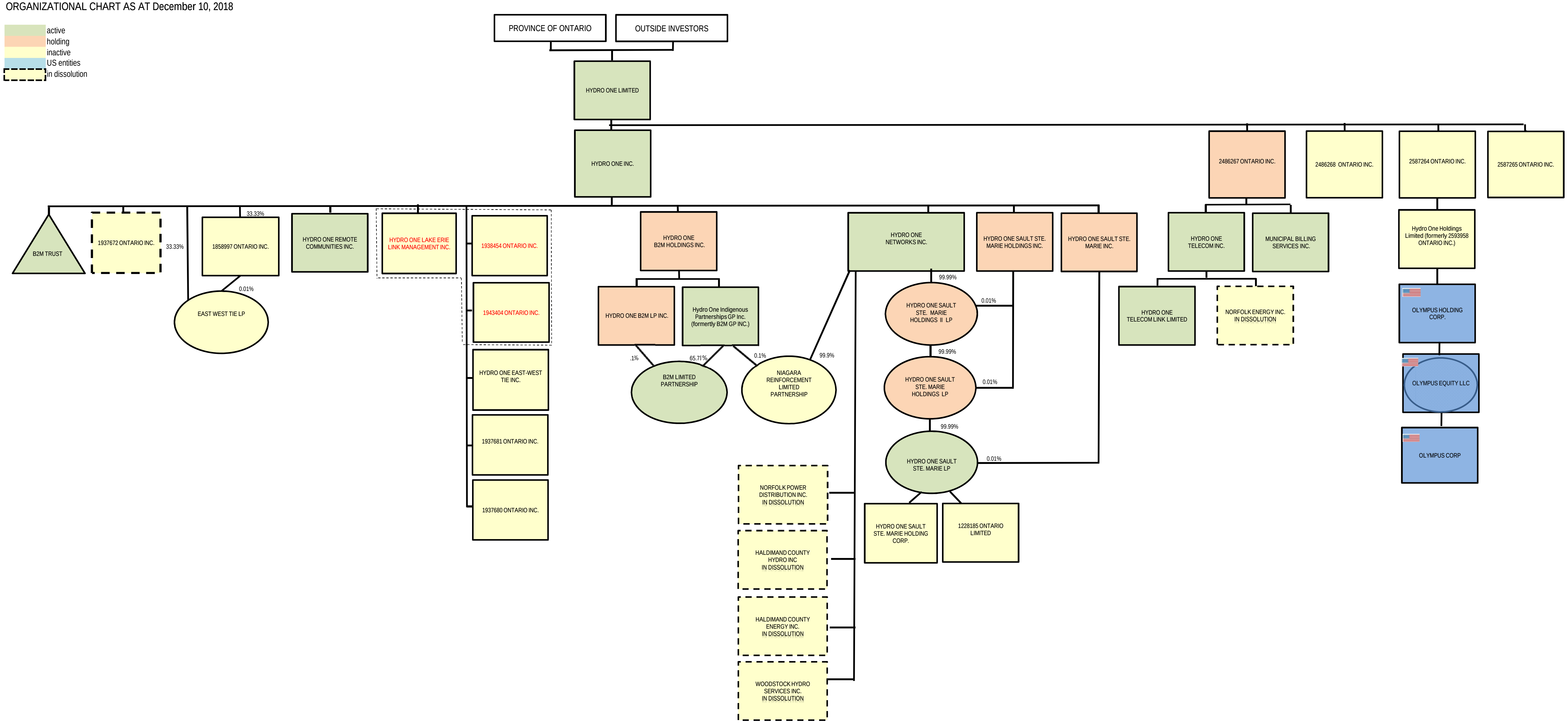
Table 17 Strength Factors

	NESC 250B Grade B	CSA Grade 1
Wood Structures	0.65	not specified - accounted for in load factors
Wood Crossarms & Braces	0.65	
Support Hardware	1.0	
Guy Wire	0.9	
Guy Anchor and Foundation	1.0	

CORPORATE ORGANIZATION CHARTS

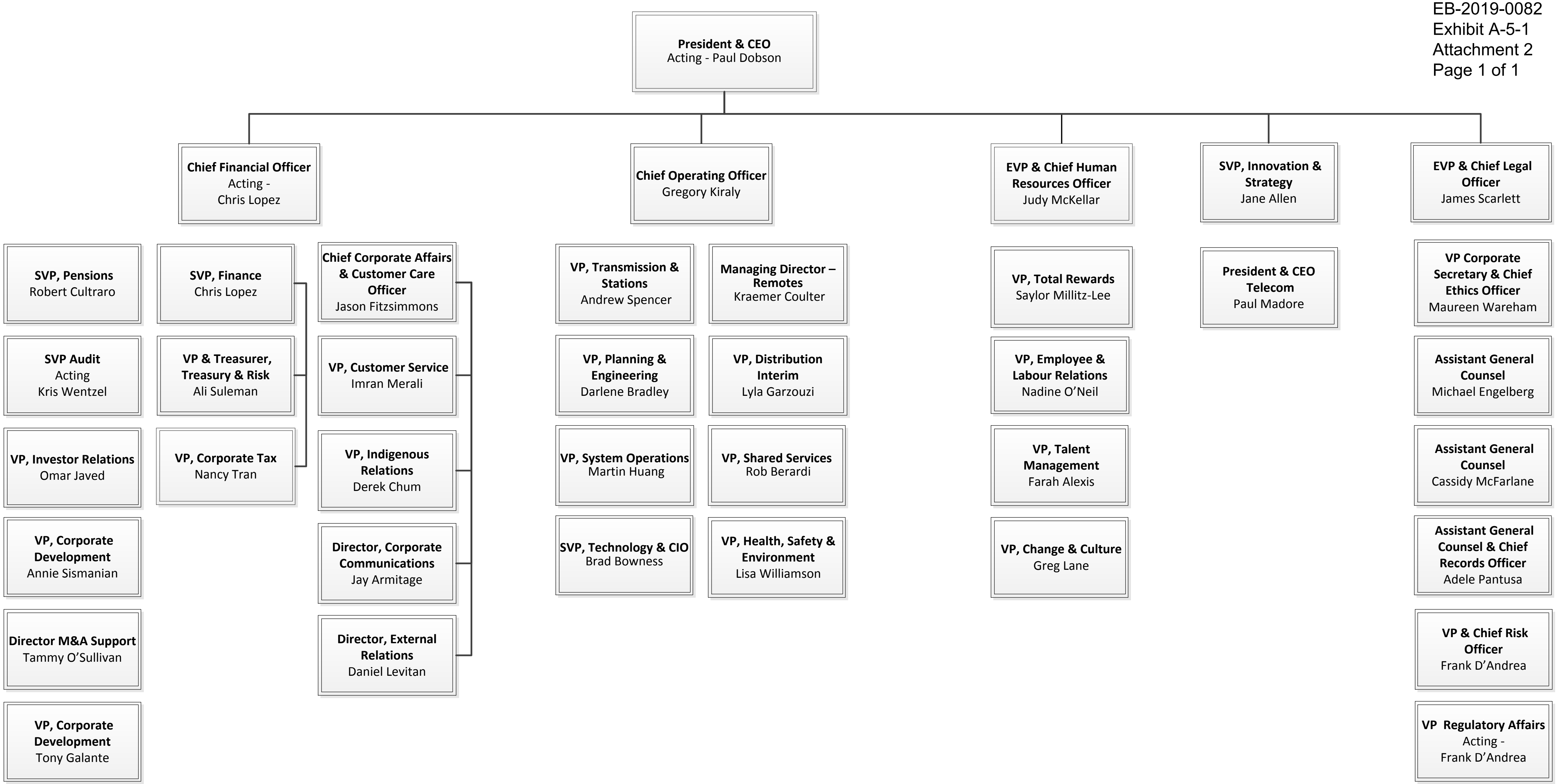
Attachment 1 sets out the corporate organizational structure for the Hydro One group of companies as at December 10, 2018. Attachment 2 sets out the executive and senior management positions within Hydro One as of January 31, 2019.

HYDRO ONE
ORGANIZATIONAL CHART AS AT December 10, 2018



Hydro One Executive Organization Structure

Filed: 2019-03-21
EB-2019-0082
Exhibit A-5-1
Attachment 2
Page 1 of 1



ACCOUNTING INFORMATION

1. ACCOUNTING STANDARD

On November 23, 2011, the OEB issued its Decision with Reasons in EB-2011-0268, granting Hydro One's request to use United States Generally Accepted Accounting Principles ("US GAAP") for regulatory purposes in its transmission business. Based on this decision, Hydro One adopted this accounting standard for regulatory purposes.

Effective January 1, 2018 Hydro One implemented the Accounting Standards Update (ASU) 2017-07 issued by the Financial Accounting Standards Board. This ASU provides guidance on the treatment of retirement benefits costs. One of the changes is that only the service cost component of retirement benefits costs are eligible for capitalization (when applicable).

Hydro One requested a deferral account as a mechanism to allow the continued capitalization of the costs no longer permissible for capitalization in ASU 2017-07, under proceeding EB-2017-0338. Further details for the Other Post-Employment Benefit (OPEB) Cost Deferral Account are provided in Exhibit H, Tab 1, Schedule 2.

On May 10, 2018, the OEB approved the establishment of the deferral account, effective January 1, 2018 until such time as the effective date of Hydro One's next transmission revenue requirement. In the deferral account Hydro One shall record the OPEB cost previously capitalized but no longer permitted to be capitalized with the issuance of ASU 2017-07. The OEB held that it could consider in Hydro One's next transmission revenue requirement proceeding (i.e. this proceeding) whether Hydro One should continue to capitalize OPEB costs, despite the new US GAAP accounting standard. Further details are provided in Exhibit H, Tab 1, Schedule 2.

In Hydro One's request for an accounting order (EB-2017-0338), Hydro One estimated that the impact of the accounting policy change to its transmission business would result in an $11 million increase to OM&A above 2018 OEB-approved levels. This impact has increased to $22 million due to the updated inputs used in the service cost calculation.

Hydro One confirms that its accounting treatment segregates any non-utility business it conducts from its rate-regulated activities.

2. CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its policies and procedures from time to time. No accounting policy changes have been made that impact the 2020-2022 rate base or revenue requirement since the OEB's review of Hydro One's transmission revenue requirements and rates for 2017 and 2018 (EB-2016-0160). The OEB approved Hydro One's application for a regulatory deferral account to maintain the capitalization of post-employment benefit related costs as part of EB-2017-0338.

3. ACCOUNTING ORDERS

With respect to the deferral accounts described in Exhibit H, Tab 1, Schedule 2, the following accounts were created subsequent to the OEB's review of Hydro One's transmission deferral accounts in EB-2016-0160:

3.1 FOREGONE TRANSMISSION REVENUE DEFERRAL ACCOUNT (EB-2016-0160)

Hydro One filed an accounting order with the OEB on October 10, 2017 pursuant to the OEB's decision on Hydro One's Transmissions rates for 2017 and 2018, which established the deferral account for the purpose of recording the differences between revenue earned by Hydro One Networks Transmission under the interim 2017 rates set at the 2016 Uniform Transmission Rates (UTR) level, and the revenues that would have been received under the approved 2017 UTR based on the OEB approved 2017 load forecast. The accounting order was approved on November 9, 2017.

3.2 OPEB COST DEFERRAL ACCOUNT (EB-2017-0338)

Hydro One Transmission proposed the establishment of a new "Other Post-Employment Benefit (OPEB) Cost Deferral Account" to record all elements of the net periodic benefit cost other than the service cost that would have been classified as capital prior to the issuance of ASU 2017-07.

The account was established as Account 1508, Other Regulatory Assets – Sub-Account "OPEB Cost Deferral Account" effective January 1, 2018 and will continue until the effective date of the transmission revenue requirement requested in this Application. Interest on any balance in the sub-account is recorded using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The accounting order was approved on June 7, 2018. Details are provided in Exhibit H, Tab 1, Schedule 2, section 3.18.2. As part of the 2019 Transmission Application before the OEB (EB-2018-0130) Hydro One requested the continuation of the deferral account for 2019.

3.3 OPEB ASYMMETRICAL CARRYING CHARGE ACCOUNT (EB-2015-0040)

In the report titled *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs* issued by the OEB on September 14, 2017 the OEB directed utilities to establish a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made. Specific details in respect of the account are provided in Exhibit H, Tab 1, Schedule 2, section 3.18.1.

3.4 REVENUE CAP INDEX PARAMETERS DIFFERENTIAL ACCOUNT (EB-2018-0130)

Hydro One filed an accounting order with the OEB on October 26, 2018 as part of Proceeding EB-2018-0130 proposing the establishment of a new “Revenue Cap Index Parameters Differential Account” to track the revenue requirement difference between proposed revenue cap index (RCI) parameters in the 2019 Transmission Application, and the final values that are approved by the OEB in EB-2018-0218. The accounting order is currently under review by the OEB.

HYDRO ONE TRANSMISSION FINANCIAL STATEMENTS - HISTORICAL YEARS 2015 - 2017

Included in this exhibit are the Historic Transmission Financial Statements:

- Attachment 1: 2015 and 2016 Audited Transmission Financial Statements
- Attachment 2: 2016 and 2017 Audited Transmission Financial Statements

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2016

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2016, the carve-out statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these carve-out financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the carve-out financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the carve-out financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the carve-out financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the carve-out financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the carve-out financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the carve-out financial statements as at and for the year ended December 31, 2016 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describes the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, and income taxes have been allocated to the Transmission Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Transmission Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 12, 2017

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2016 and 2015

Year ended December 31 *(millions of Canadian dollars)*	2016	2015
Revenues		
Transmission tariff *(Note 21)*	1,512	1,456
Other	39	35
	1,551	1,491
Costs		
Operation, maintenance and administration *(Note 21)*	409	442
Depreciation and amortization *(Note 4)*	380	366
	789	808
Income before financing charges and income taxes	**762**	**683**
Financing charges *(Notes 5, 21)*	220	216
Income before income taxes	**542**	**467**
Income taxes *(Notes 6, 21)*	76	64
Net income	**466**	**403**
Other comprehensive income	–	–
Comprehensive income	**466**	**403**

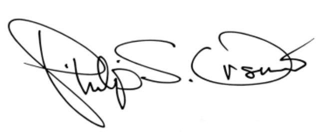
See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2016 and 2015

December 31 *(millions of Canadian dollars)*	2016	2015
Assets		
Current assets:		
Accounts receivable	38	29
Due from related parties *(Note 21)*	134	119
Other current assets *(Note 7)*	32	33
	204	181
Property, plant and equipment *(Note 8)*	11,148	10,549
Other long-term assets:		
Regulatory assets *(Note 10)*	1,256	1,174
Intangible assets *(Note 9)*	110	107
Other assets	2	2
	1,368	1,283
Total assets	**12,720**	**12,013**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 21)*	213	749
Long-term debt payable within one year *(Notes 13, 21)*	405	300
Accounts payable and other current liabilities *(Note 11)*	275	290
Due to related parties *(Note 21)*	124	59
	1,017	1,398
Long-term liabilities:		
Long-term debt *(Notes 13, 21)*	5,503	4,674
Deferred income tax liabilities *(Note 6)*	998	910
Regulatory liabilities *(Note 10)*	128	146
Other long-term liabilities *(Note 12)*	801	760
	7,430	6,490
Total liabilities	**8,447**	**7,888**
Contingencies and Commitments (Notes 23, 24)		
Subsequent Events (Note 25)		
Excess of assets over liabilities *(Notes 15, 19)*	4,273	4,125
Total liabilities and excess of assets over liabilities	**12,720**	**12,013**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:



Philip Orsino
Chair, Audit Committee

Mayo Schmidt
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2016 and 2015

Year ended December 31 *(millions of Canadian dollars)*	2016	2015
Operating activities		
Net income	466	403
Environmental expenditures	(7)	(7)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	346	336
Regulatory assets and liabilities	(8)	59
Deferred income taxes	–	(32)
Other	8	21
Changes in non-cash balances related to operations *(Note 22)*	94	63
Net cash from operating activities	899	843
Financing activities		
Long-term debt issued	1,240	–
Long-term debt retired	(300)	(330)
Payments to finance dividends and return on stated capital	(343)	(625)
Other	(5)	–
Net cash from (used in) financing activities	592	(955)
Investing activities		
Capital expenditures *(Note 22)*		
Property, plant and equipment	(955)	(925)
Intangible assets	(22)	(8)
Capital contributions received *(Note 22)*	21	64
Other	1	(2)
Net cash used in investing activities	(955)	(871)
Net change in inter-company demand facility	536	(983)
Inter-company demand facility, beginning of year	(749)	234
Inter-company demand facility, end of year	**(213)**	**(749)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB and as a result, may not be suitable for any other purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2016 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Transmission Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Transmission Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Transmission Business was a separate taxpaying entity. However, income taxes paid and the deferred tax asset recognized by the Company in relation to the Company losing its exemption from tax under the Federal Tax Regime have been excluded as they represent transactions that are not included in the rate-setting process of the Transmission Business. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 12, 2017, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See note 25 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations, asset impairments, contingencies, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

In November 2015, the OEB approved Hydro One Networks' 2016 transmission rates revenue requirement of $1,480 million.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting of future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers. Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable represents earned revenue for electricity transmitted and delivered to customers and receivable from the Independent Electricity System Operator (IESO). Trade accounts receivable are recorded at the amount reported by the IESO. No allowance for doubtful accounts is recognized with respect to trade accounts receivable as there is no risk of loss associated with such amounts.

Income Taxes

Prior to October 31, 2015, Hydro One Networks was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (Federal Tax Regime). However, under the *Electricity Act*, Hydro One Networks was required to make payments in lieu of tax (PILs) to the Ontario Electricity Financial Corporation (OEFC) (PILs Regime). The PILs were, in general, based on the amount of tax that Hydro One Networks would otherwise be liable to pay under the Federal Tax Regime if it was not exempt from taxes under those statutes. On October 31, 2015, Hydro One Networks' exemption from tax under the Federal Tax Regime ceased to apply. Upon exiting the PILs Regime, Hydro One Networks is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Transmission Business records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Transmission Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	55 years	1% – 2%	2%
Communication	17 years	1% – 7%	5%
Administration and service	17 years	1% – 20%	8%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2016 and 2015, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable to be reasonable estimates of fair value because of the short time to maturity of these instruments. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. Hydro One Networks determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with its risk management policy disclosed in note 14 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2016 or 2015.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets of Hydro One for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in note 18 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in note 18 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2016.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date share price of Hydro One Limited common shares. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Forfeitures are recognized as they occur (see note 3).

Directors' Deferred Share Unit (DSU) Plan

The Company records the liabilities associated with its Directors' DSU Plan at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures its LTIP at fair value based on the grant date share price of Hydro One Limited common shares. The related compensation expense of the Company is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Transmission Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Transmission Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. The Company reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Transmission Business expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Transmission Business' asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Impact on Hydro One
2015-01	January 2015	Extraordinary items are no longer required to be presented separately in the income statement.	January 1, 2016	No material impact upon adoption
2015-03	April 2015	Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums.	January 1, 2016	Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively. (See note 13)
2015-05	April 2015	Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software.	January 1, 2016	No material impact upon adoption
2015-17	November 2015	All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.	January 1, 2017	This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the Balance Sheet. Prior periods were not retrospectively adjusted. (See note 6)
2016-09	March 2016	Several aspects of the accounting for stock-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	January 1, 2017	This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption.

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20	May 2014 – December 2016	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	The Company has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	Under assessment

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2016	2015
Depreciation of property, plant and equipment	320	309
Asset removal costs	34	30
Amortization of intangible assets	19	20
Amortization of regulatory assets	7	7
	380	366

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2016	2015
Interest on long-term debt *(Note 21)*	248	248
Interest on inter-company demand facility *(Note 21)*	5	–
Other	9	8
Less: Interest capitalized on construction and development in progress	(42)	(37)
Gain on interest-rate swap agreements	–	(1)
Interest earned on inter-company demand facility *(Note 21)*	–	(2)
	220	216

6. INCOME TAXES

Income taxes / provision for PILs differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2016	2015
Income taxes / provision for PILs at statutory rate	144	124
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(37)	(28)
Interest capitalized for accounting but deducted for tax purposes	(11)	(9)
Overheads capitalized for accounting but deducted for tax purposes	(9)	(9)
Pension contributions in excess of pension expense	(8)	(12)
Environmental expenditures	(2)	(2)
Other	(2)	(1)
Net temporary differences	(69)	(61)
Net permanent differences	1	1
Total income taxes / provision for PILs	76	64

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2016	2015
Current income taxes / provision for PILs	76	96
Deferred income taxes / recovery of PILs	–	(32)
Total income taxes / provision for PILs	76	64
Effective income tax rate	14.0%	13.7%

The provision for current income taxes / PILs is remitted to the CRA (Federal Tax Regime) and the OEFC (PILs Regime). At December 31, 2016, $8 million (2015 – $17 million) payable to the CRA was included in accrued liabilities and $57 million (2015 – $55 million) payable to the OEFC was included in due to related parties.

The 2016 total income taxes / provision for PILs included deferred recovery of $nil (2015 – $32 million) that is not included in the rate-setting process. Deferred income tax balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2016 and 2015, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2016	2015
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,248)	(1,142)
Regulatory amounts not recognized for tax	(34)	(31)
Post-retirement and post-employment benefits expense in excess of cash payments	260	247
Environmental expenditures	30	29
Other	(6)	(5)
Total deferred income tax liabilities	(998)	(902)
Less: current portion	–	8
	(998)	(910)

7. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2016	2015
Materials and supplies	12	11
Regulatory assets *(Note 10)*	10	5
Prepaid expenses and other assets	10	9
Deferred income tax assets *(Notes 3, 6)*	–	8
	32	33

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,001	4,849	906	10,058
Communication	929	593	9	345
Administration and service	559	300	28	287
Easements	517	59	–	458
	16,006	5,801	943	11,148

[1] Includes future use assets totalling $95 million.

December 31, 2015 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,236	4,616	851	9,471
Communication	882	545	18	355
Administration and service	521	271	18	268
Easements	512	57	–	455
	15,151	5,489	887	10,549

[1] Includes future use assets totalling $96 million.

Financing charges capitalized on property, plant and equipment under construction were $41 million in 2016 (2015 – $37 million).

9. INTANGIBLE ASSETS

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	235	148	22	109
Other	4	3	–	1
	239	151	22	110

December 31, 2015 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	227	129	8	106
Other	4	3	–	1
	231	132	8	107

Financing charges capitalized to intangible assets under development were $1 million in 2016 (2015 – $nil). The estimated annual amortization expense for intangible assets is as follows: 2017 – $20 million; 2018 – $20 million; 2019 – $15 million; 2020 – $6 million; and 2021 – $6 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2016	2015
Regulatory assets:		
Deferred income tax regulatory asset	1,060	973
Post-retirement and post-employment benefits	105	104
Environmental	85	82
Stock-based compensation	14	5
Pension cost variance	–	14
Other	2	1
Total regulatory assets	1,266	1,179
Less: current portion	10	5
	1,256	1,174
Regulatory liabilities:		
External revenue variance	64	87
CDM deferral variance	54	53
Pension cost variance	4	–
Deferred income tax regulatory liability	–	9
Other	6	6
Total regulatory liabilities	128	155
Less: current portion	–	9
	128	146

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Transmission Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2016 income tax expense would have been higher by approximately $70 million (2015 – $61 million).

Post-Retirement and Post-Employment Benefits

The Transmission Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the re-measurement adjustment. In the absence of rate-regulated accounting, 2016 OCI would have been lower by $1 million (2015 – higher by $15 million).

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2016, the environmental regulatory asset increased by $5 million (2015 – decreased by $7 million) to reflect related changes in the PCB liability, and increased by $1 million (2015 – $nil) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $6 million (2015 – lower by $7 million). In addition, 2016 amortization expense would have been lower by $7 million (2015 – $6 million), and 2016 financing charges would have been higher by $4 million (2015 – $4 million).

Stock-based Compensation

The Transmission Business recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that costs associated with share grant plans will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $4 million (2015 – $2 million).

Pension Cost Variance

A pension cost variance account was established for the Transmission Business to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2016 revenue would have been higher by $10 million (2015 – lower by $3 million).

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, the Company agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirement, respectively. There were no additions to this regulatory account in 2016.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2016	2015
Accrued liabilities	110	137
Accounts payable	103	86
Accrued interest *(Note 21)*	62	58
Regulatory liabilities *(Note 10)*	–	9
	275	290

12. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2016	2015
Post-retirement and post-employment benefit liability *(Note 16)*	697	662
Environmental liabilities *(Note 17)*	75	77
Long-term accounts payable and other liabilities	14	12
Long-term inter-company payable *(Note 21)*	11	5
Asset retirement obligations *(Note 18)*	4	4
	801	760

13. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Transmission Business as at December 31, 2016 and 2015:

December 31 *(millions of dollars)*	2016	2015
Long-term debt	5,926	4,986
Add: Net unamortized debt premiums[1]	7	8
Add: Unrealized mark-to-market gain[2]	(1)	–
Less: Deferred debt issuance costs[1]	(24)	(20)
Less: Long-term debt payable within one year	(405)	(300)
Long-term debt	5,503	4,674

[1] Effective January 1, 2016, deferred debt issuance costs and net unamortized debt premiums were reclassified from other long-term assets and other long-term liabilities, respectively, as an offset to long-term debt upon adoption of ASU 2015-03 (see note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

[2] At December 31, 2016, the unrealized mark-to-market gain related to Transmission Business' $300 million notes due 2019. This gain was offset by $1 million unrealized mark-to-market loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2016, Hydro One issued $2,300 million (2015 – $350 million) of long-term debt under its MTN Program, of which $2,290 million (2015 – $30 million) was mirrored down to Hydro One Networks and $1,240 million (2015 – $nil) was allocated to the Company's Transmission Business.

In 2016, Hydro One repaid $500 million (2015 – $550 million) of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $500 million (2015 – $550 million) to Hydro One, of which $300 million (2015 – $330 million) was allocated to the Company's Transmission Business.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	405	5.2
2 years	412	2.8
3 years	437	1.6
4 years	180	4.4
5 years	250	2.1
	1,684	3.1
6 – 10 years	564	3.1
Over 10 years	3,678	5.3
	5,926	4.5

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2017	264
2018	242
2019	230
2020	220
2021	202
	1,158
2022-2026	1,004
2027 +	2,658
	4,820

14. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2016 and 2015, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Transmission Business' long-term debt at December 31, 2016 and 2015 are as follows:

December 31 *(millions of dollars)*	2016 Carrying Value	2016 Fair Value	2015 Carrying Value	2015 Fair Value
Long-term debt, including current portion				
$300 million notes due 2019	299	299	–	–
Other notes and debentures	5,609	6,393	4,974	5,729
	5,908	6,692	4,974	5,729

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2016, the Transmission Business' share of the Company's derivative instruments include $300 million (2015 – $nil) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These interest-rate swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was equal to about 5% (2015 – 0%) of its total long-term debt. At December 31, 2016, the Transmission Business' interest-rate swaps designated as fair value hedges were as follows:

- $300 million fixed-to-floating interest-rate swap agreements to convert $300 million notes maturing on November 18, 2019 into three-month variable rate debt.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2016 and 2015 is as follows:

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	213	213	213	–	–
Long-term debt, including current portion	5,908	6,692	–	6,692	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	6,122	6,906	213	6,693	–

December 31, 2015 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	749	749	749	–	–
Long-term debt, including current portion	4,974	5,729	–	5,729	–
	5,723	6,478	749	5,729	–

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2016 and 2015.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2016 or 2015.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Transmission Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2016 and 2015 was not significant.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2016 and 2015, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business did not earn a significant amount of revenue from any single customer. At December 31, 2016 and 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2016, the Transmission Business' provision for bad debts was $nil (2015 – $1 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2016, approximately 3% (2015 – 9%) of the Transmission Business' net accounts receivable were aged more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund normal operating requirements.

At December 31, 2016, accounts payable and accrued liabilities in the amount of $213 million (2015 – $223 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

15. CAPITAL MANAGEMENT

The Transmission Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB. At December 31, 2016 and 2015, the Transmission Business' capital structure was as follows:

December 31 *(millions of dollars)*	2016	2015
Long-term debt payable within one year	405	300
Inter-company demand facility	213	749
	618	1,049
Long-term debt	5,503	4,674
Excess of assets over liabilities	4,273	4,125
Total capital	10,394	9,848

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2016 and 2015:

December 31 *(millions of dollars)*	2016	2015
Excess of assets over liabilities, January 1	4,125	4,372
Net income	466	403
Payments to Hydro One to finance dividends and return of stated capital *(Note 19)*	(318)	(650)
Excess of assets over liabilities, December 31	4,273	4,125

16. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplementary pension plan, and post-retirement and post-employment benefit plans.

Defined Contribution Pension Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan is mandatory and covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One Networks contributions to the DC Plan for the year ended December 31, 2016 were less than $1 million (2015 – $nil). At December 31, 2016, Company contributions payable included in accrued liabilities on the Balance Sheets were less than $1 million (2015 – $nil).

Defined Benefit Pension Plan

The Pension Plan is a defined benefit contributory plan which covers all regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2016 of $108 million (2015 – $177 million) were based on an actuarial valuation effective December 31, 2015 (2015 – based on an actuarial valuation effective December 31, 2013) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings. Future minimum contributions beyond 2018 will be based on an actuarial valuation effective no later than December 31, 2018. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Hydro One Supplemental Pension Plan (Supplemental Plan) provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

At December 31, 2016, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,774 million (2015 – $7,683 million). The fair value of pension plan assets available for these benefits was $6,874 million (2015 – $6,731 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2016, the Transmission Business charged $19 million (2015 – $20 million) of post-retirement and post-employment benefit costs to operations, and capitalized $35 million (2015 – $29 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2016 were $19 million (2015 – $20 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was increased by $1 million (2015 – decreased by $15 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

December 31 *(millions of dollars)*	2016	2015
Accrued liabilities	26	25
Post-retirement and post-employment benefit liability	697	662
	723	687

17. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2016 and 2015:

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	71	11	82
Interest accretion	4	–	4
Expenditures	(3)	(4)	(7)
Revaluation adjustment	5	1	6
Environmental liabilities, December 31	77	8	85
Less: current portion	8	2	10
	69	6	75

Year ended December 31, 2015 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	77	14	91
Interest accretion	4	–	4
Expenditures	(3)	(3)	(6)
Revaluation adjustment	(7)	–	(7)
Environmental liabilities, December 31	71	11	82
Less: current portion	2	3	5
	69	8	77

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	85	9	94
Less: discounting accumulated liabilities to present value	8	1	9
Discounted environmental liabilities	77	8	85

December 31, 2015 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	81	11	92
Less: discounting accumulated liabilities to present value	10	–	10
Discounted environmental liabilities	71	11	82

At December 31, 2016, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017	10
2018	9
2019	9
2020	10
2021	18
Thereafter	38
	94

The Transmission Business records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 5.1%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $85 million (2015 – $81 million). These expenditures are expected to be incurred over the period from 2017 to 2024. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2016 to increase the PCB environmental liability by $5 million (2015 – decrease by $7 million).

Land Assessment and Remediation

The Transmission Business' best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $9 million (2015 – $11 million). These expenditures are expected to be incurred over the period from 2017 to 2022. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2016 to increase the land assessment and remediation environmental liability by $1 million (2015 – $nil).

18. ASSET RETIREMENT OBLIGATIONS

The Company records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligations, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2016, the Company had recorded asset retirement obligations of $4 million (2015 – $4 million) related to its Transmission Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

19. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2016 and 2015, Hydro One Networks had 207,577,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2016, Hydro One Networks declared common share dividends in the amount of $2 million (2015 – $875 million), preferred share dividends of $nil (2015 – $16 million), and made a return of stated capital of $609 million (2015 – $nil) to Hydro One. The amount allocated to the Transmission Business to finance these dividends and return of stated capital was $318 million (2015 – $650 million).

20. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

At December 31, 2016, Hydro One Limited had two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan begins on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 1,761,152 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 608,626 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The 2015 fair value of Hydro One Limited shares granted to employees of Hydro One Networks and allocated to the Transmission Business was $49 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. No shares were granted under the Share Grant Plans in 2016. Total stock-based compensation recognized during 2016 by the Transmission Business was $9 million (2015 – $5 million) and was recorded as a regulatory asset.

A summary of the Transmission Business' share grant activity under the Share Grant Plans during years ended December 31, 2016 and 2015 is presented below:

Year ended December 31, 2016	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding – January 1	2,369,778	$20.50
Granted (non-vested)	–	–
Forfeited[1]	(36,900)	$20.50
Share grants outstanding – December 31	2,332,878	$20.50

[1] Includes shares forfeited as well as shares transferred corresponding to transfer of employees between affiliate companies.

Year ended December 31, 2015	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding – January 1	–	–
Granted (non-vested)	2,369,778	$20.50
Share grants outstanding – December 31	2,369,778	$20.50

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

Year ended December 31 *(number of DSUs)*	2016	2015
DSUs outstanding – January 1	7,958	–
DSUs granted	30,458	7,958
DSUs outstanding – December 31	38,416	7,958

For the year ended December 31, 2016, an expense of $1 million (2015 – less than $1 million) was recognized in earnings by the Transmission Business with respect to the DSU Plan. At December 31, 2016, a liability of $1 million (2015 – less than $1 million), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $23.58.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. Hydro One Networks matches 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. In 2016, contributions made by the Transmission Business under the ESOP were $1 million (2015 – $nil).

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other stock-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2016, Hydro One Limited granted awards under its LTIP, consisting of PSUs and RSUs, all of which are equity settled in Hydro One Limited shares. A summary of the Transmission Business' share is as follows:

	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2016	–	–
Units granted	86,487	97,618
Units forfeited	(1,535)	(1,535)
Units outstanding – December 31, 2016	84,952	96,083

The grant date total fair value of the awards was $5 million (2015 – $nil). The compensation expense recognized by the Transmission Business relating to these awards during 2016 was $1 million (2015 – $nil).

21. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The IESO, Ontario Power Generation Inc. (OPG), OEFC, OEB, Hydro One Brampton and Hydro One Telecom are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province or by Hydro One Limited.

		Year ended December 31	
		2016	2015
Related Party	Transaction	*(millions of dollars)*	
IESO	Transmission services – amounts received[1]	1,510	1,508
OPG	Revenues related to provision of construction and equipment maintenance services	4	6
	Costs expensed related to the purchase of services	1	–
OEFC	Payments in lieu of corporate income taxes	–	36
	Indemnification fee paid (terminated effective October 31, 2015)	–	7
OEB	OEB fees	4	5
Hydro One Brampton[2]	Capital contributions received	–	8
Hydro One Limited and its subsidiaries	Revenues for services provided	3	3
	Services received – costs expensed	20	20
	Services received – costs capitalized	12	11
	Interest expense on long-term debt	248	248
	Interest expense (income) on inter-company demand facility	5	(2)
	Payments to finance dividends and return of stated capital	318	650
	Stock-based compensation costs	10	5

[1] Consistent with the Company's revenue recognition policy, the Transmission Business recognized revenues of $1,512 million in 2016 (2015 – $1,456 million).

[2] On February 28, 2017, Hydro One Brampton was acquired by Alectra Inc. from the Province, and as such, effective this date, Hydro One Brampton is no longer a related party to Hydro One.

The amounts due to and from related parties at December 31, 2016 and 2015 are as follows:

December 31 *(millions of dollars)*	2016	2015
Inter-company demand facility	(213)	(749)
Due from related parties	134	119
Due to related parties	(124)	(59)
Accrued interest	(62)	(58)
Long-term inter-company payable	(11)	(5)
Long-term debt, including current portion	(5,908)	(4,974)

22. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2016	2015
Accounts receivable	(7)	19
Due from related parties	(15)	16
Materials and supplies	(1)	2
Other assets	(1)	(1)
Accounts payable	19	–
Due to related parties	65	34
Accrued liabilities	(6)	(32)
Accrued interest	4	(2)
Long-term accounts payable and other liabilities	2	(1)
Post-retirement and post-employment benefit liability	34	28
	94	63

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amount presented on the Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2016	2015
Capital investments in property, plant and equipment	(965)	(934)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	10	9
Capital expenditures – property, plant and equipment	(955)	(925)

The following table reconciles investments in intangible assets and the amount presented in the Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2016	2015
Capital investments in intangible assets	(22)	(9)
Net change in accruals included in capital investments in intangible assets	–	1
Capital expenditures – intangible assets	(22)	(8)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2016, capital contributions to the Transmission Business from these reassessments totalled $21 million (2015 – $64 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2016	2015
Net interest paid	244	250
Income taxes / PILs paid	14	38

23. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

24. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

25. SUBSEQUENT EVENTS

Payments to Finance Dividends and Return of Stated Capital

On February 9, 2017, Hydro One Networks declared common share dividends in the amount of $2 million, and a return of stated capital in the amount of $124 million was approved. The amount allocated to the Transmission Business to finance these payments was $76 million.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2017

INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2017, the carve-out statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these carve-out financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the carve-out financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the carve-out financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the carve-out financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the carve-out financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the carve-out financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the carve-out financial statements as at and for the year ended December 31, 2017 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describes the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, and income taxes have been allocated to the Transmission Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Transmission Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 27, 2018

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Revenues		
Transmission tariff *(Note 21)*	1,489	1,512
Other	30	39
	1,519	1,551
Costs		
Operation, maintenance and administration *(Note 21)*	386	409
Depreciation and amortization *(Note 4)*	403	380
	789	789
Income before financing charges and income taxes	**730**	**762**
Financing charges *(Notes 5, 21)*	230	220
Income before income taxes	**500**	**542**
Income taxes *(Note 6)*	67	76
Net income	**433**	**466**
Other comprehensive income	—	—
Comprehensive income	**433**	**466**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Accounts receivable	40	38
Due from related parties *(Note 21)*	158	134
Other current assets *(Note 7)*	60	32
	258	204
Property, plant and equipment *(Note 8)*	11,719	11,148
Other long-term assets:		
Regulatory assets *(Note 10)*	1,297	1,256
Intangible assets *(Note 9)*	117	110
Other assets	1	2
	1,415	1,368
Total assets	**13,392**	**12,720**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 21)*	1,071	213
Long-term debt payable within one year *(Notes 13, 14, 21)*	413	405
Accounts payable and other current liabilities *(Note 11)*	264	275
Due to related parties *(Note 21)*	179	124
	1,927	1,017
Long-term liabilities:		
Long-term debt *(Notes 13, 14, 21)*	5,087	5,503
Deferred income tax liabilities *(Note 6)*	1,128	998
Regulatory liabilities *(Note 10)*	39	128
Other long-term liabilities *(Note 12)*	753	801
	7,007	7,430
Total liabilities	**8,934**	**8,447**
Contingencies and Commitments (Notes 23, 24)		
Subsequent Events (Note 25)		
Excess of assets over liabilities *(Notes 15, 19)*	4,458	4,273
Total liabilities and excess of assets over liabilities	**13,392**	**12,720**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Philip Orsino
Chair, Audit Committee

Mayo Schmidt
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	433	466
Environmental expenditures	(8)	(7)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	364	346
Regulatory assets and liabilities	(66)	(8)
Deferred income taxes	17	—
Other	5	8
Changes in non-cash balances related to operations *(Note 22)*	(19)	94
Net cash from operating activities	**726**	**899**
Financing activities		
Long-term debt issued	—	1,240
Long-term debt repaid	(405)	(300)
Payments to finance dividends and return on stated capital	(248)	(343)
Other	—	(5)
Net cash from (used in) financing activities	**(653)**	**592**
Investing activities		
Capital expenditures *(Note 22)*		
Property, plant and equipment	(917)	(955)
Intangible assets	(24)	(22)
Capital contributions received *(Note 22)*	9	21
Other	1	1
Net cash used in investing activities	**(931)**	**(955)**
Net change in inter-company demand facility	(858)	536
Inter-company demand facility, beginning of year	(213)	(749)
Inter-company demand facility, end of year	**(1,071)**	**(213)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The Transmission Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB and as a result, may not be suitable for any other purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2017 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Transmission Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company’s Transmission Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company’s long-term debt is allocated based on the respective borrowing requirements of the Company’s transmission and distribution businesses. A portion of the Company’s shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Transmission Business was a separate taxpaying entity. However, income taxes paid and the deferred tax asset recognized by the Company in relation to the Company losing its exemption from tax under the Federal Tax Regime have been excluded as they represent transactions that are not included in the rate-setting process of the Transmission Business. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 27, 2018, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See note 25 - Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations, asset impairments, contingencies, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

In November 2017, the OEB approved Hydro One Networks’ 2017 transmission rates revenue requirement of $1,438 million. See Note 10 - Regulatory Assets and Liabilities for additional information.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers. Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable represents earned revenue for electricity transmitted and delivered to customers and receivable from the Independent Electricity System Operator (IESO). Trade accounts receivable are recorded at the amount reported by the IESO. No allowance for doubtful accounts is recognized with respect to trade accounts receivable as there is no risk of loss associated with such amounts.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Transmission Business records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

The Transmission Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company’s weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2017 for Hydro One Networks' transmission business. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	55 years	1% - 2%	2%
Communication	17 years	1% - 7%	5%
Administration and service	20 years	1% - 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2017 and 2016, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 14 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2017 or 2016.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with the Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under Hydro One Limited's LTIP, at fair value based on the grant date Hydro One Limited common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Transmission Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Transmission Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Transmission Business expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Transmission Business' asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One Networks has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One Networks has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	335	320
Asset removal costs	39	34
Amortization of intangible assets	21	19
Amortization of regulatory assets	8	7
	403	380

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt *(Note 21)*	259	248
Interest on inter-company demand facility *(Note 21)*	8	5
Other	8	9
Less: Interest capitalized on construction and development in progress	(45)	(42)
	230	220

6. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	500	542
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	133	144
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(34)	(37)
Pension contributions in excess of pension expense	(7)	(8)
Overheads capitalized for accounting but deducted for tax purposes	(10)	(9)
Interest capitalized for accounting but deducted for tax purposes	(12)	(11)
Environmental expenditures	(2)	(2)
Other	(2)	(2)
Net temporary differences	(67)	(69)
Net permanent differences	1	1
Total income taxes	67	76

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	50	76
Deferred income taxes	17	—
Total income taxes	67	76
Effective income tax rate	13.4%	14.0%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,370)	(1,248)
Regulatory amounts that are not recognized for tax purposes	(17)	(34)
Post-retirement and post-employment benefits expense in excess of cash payments	241	260
Environmental expenditures	28	30
Other	(7)	(6)
	(1,125)	(998)
Less: valuation allowance	(3)	—
Total deferred income tax liabilities	(1,128)	(998)

7. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 10)*	14	10
Prepaid expenses and other assets	35	10
Materials and supplies	11	12
	60	32

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,807	5,135	986	10,658
Communication	938	642	21	317
Administration and service	554	292	20	282
Easements	523	61	—	462
	16,822	6,130	1,027	11,719

[1] Includes future use assets totalling $97 million.

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,001	4,849	906	10,058
Communication	929	593	9	345
Administration and service	559	300	28	287
Easements	517	59	—	458
	16,006	5,801	943	11,148

[1] Includes future use assets totalling $95 million.

Financing charges capitalized on property, plant and equipment under construction were $44 million in 2017 (2016 - $41 million).

9. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	268	169	17	116
Other	4	3	—	1
	272	172	17	117

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	235	148	22	109
Other	4	3	—	1
	239	151	22	110

Financing charges capitalized to intangible assets under development were $1 million in 2017 (2016 - $1 million). The estimated annual amortization expense for intangible assets is as follows: 2018 - $23 million; 2019 - $18 million; 2020 - $10 million; 2021 - $9 million; and 2022 - $8 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Transmission Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	1,172	1,060
Environmental	78	85
Stock-based compensation	20	14
Post-retirement and post-employment benefits	16	105
Foregone revenue deferral	22	—
Other	3	2
Total regulatory assets	1,311	1,266
Less: current portion	(14)	(10)
	1,297	1,256
Regulatory liabilities:		
External revenue variance	46	64
CDM deferral variance	28	54
Pension cost variance	10	4
Other	1	6
Total regulatory liabilities	85	128
Less: current portion	(46)	—
	39	128

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Transmission Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2017 income tax expense would have been higher by approximately $81 million (2016 - $70 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $515 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company’s Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Post-Retirement and Post-Employment Benefits

The Transmission Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2017 OCI would have been higher by $89 million (2016 - lower by $1 million).

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2017, the environmental regulatory asset decreased by $1 million (2016 - increased by $5 million) to reflect related changes in the Company's PCB liability, and decreased by $1 million (2016 - increased by $1 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Transmission Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been lower by $2 million (2016 - higher by $6 million). In addition, 2017 amortization expense would have been lower by $8 million (2016 - $7 million), and 2017 financing charges would have been higher by $3 million (2016 - $4 million).

Stock-Based Compensation

The Transmission Business recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $3 million (2016 - $4 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The balance of this account will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Pension Cost Variance

A pension cost variance account was established for the Transmission Business to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the deficit of pension costs paid as compared to OEB-approved amounts. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $3 million (2016 - $10 million).

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accrued liabilities	66	110
Accounts payable	94	103
Accrued interest *(Note 21)*	58	62
Regulatory liabilities *(Note 10)*	46	—
	264	275

12. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 16)*	646	697
Environmental liabilities *(Note 17)*	69	75
Long-term inter-company payable *(Note 21)*	18	11
Long-term accounts payable and other liabilities	16	14
Asset retirement obligations *(Note 18)*	4	4
	753	801

13. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Transmission Business outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
Long-term debt	5,521	5,926
Add: Net unamortized debt premiums	6	7
Add: Unrealized mark-to-market gain[1]	(5)	(1)
Less: Deferred debt issuance costs	(22)	(24)
Less: Long-term debt payable within one year	(413)	(405)
Long-term debt	5,087	5,503

[1] The unrealized mark-to-market net gain relates to $300 million notes due in 2019. The unrealized mark-to-market net gain is offset by a $5 million (2016 - $1 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreement, which is accounted for as fair value hedge.

In 2017, Hydro One did not issue any long-term debt. In 2016, Hydro One issued $2,300 million of long-term debt under its MTN Program, of which $2,290 million was mirrored down to Hydro One Networks and $1,240 million was allocated to the Company's Transmission Business.

In 2017, Hydro One repaid $600 million (2016 – $500 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $600 million (2016 – $500 million) to Hydro One, of which $405 million (2016 – $300 million) was allocated to the Company's Transmission Business.

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	413	2.8
2 years	437	1.8
3 years	180	4.4
4 years	250	2.1
5 years	319	3.2
	1,599	2.7
6 – 10 years	245	3.0
Over 10 years	3,677	5.3
	5,521	4.4

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments (millions of dollars)
2018	244
2019	230
2020	220
2021	213
2022	206
	1,113
2023-2027	992
2028+	2,464
	4,569

14. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2017 and 2016, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Transmission Business' long-term debt at December 31, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$300 million notes due 2019	295	295	299	299
Other notes and debentures	5,205	6,096	5,609	6,393
Long-term debt, including current portion	5,500	6,391	5,908	6,692

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

At December 31, 2017, the Transmission Business' share of the Company's derivative instruments include a $300 million (2016 – $300 million) interest-rate swap that was used to convert fixed-rate debt to floating-rate debt. This swap is classified as a fair value hedge. The Transmission Business' fair value hedge exposure was approximately 5% (2016 – 5%) of its total long-term debt. At December 31, 2017, the Transmission Business' interest-rate swap designated as a fair value hedge was as follows:

- a $300 million fixed-to-floating interest-rate swap agreement to convert $300 million notes maturing on November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	1,071	1,071	1,071	—	—
Long-term debt, including current portion	5,500	6,391	—	6,391	—
Derivative instruments					
Fair value hedge – interest-rate swap	5	5	—	5	—
	6,576	7,467	1,071	6,396	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	213	213	213	—	—
Long-term debt, including current portion	5,908	6,692	—	6,692	—
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	—	1	—
	6,122	6,906	213	6,693	—

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Transmission Business' net income for the years ended December 31, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Transmission Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business' revenue is earned from a broad base of customers. As a result, the Transmission Business did not earn a material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 3% (2016 – 3%) of the Transmission Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on the Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund normal operating requirements.

15. CAPITAL MANAGEMENT

The Transmission Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. At December 31, 2017 and 2016, the Transmission Business' capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	413	405
Inter-company demand facility	1,071	213
	1,484	618
Long-term debt	5,087	5,503
Excess of assets over liabilities	4,458	4,273
Total capital	11,029	10,394

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Excess of assets over liabilities - beginning	4,273	4,125
Net income	433	466
Payments to Hydro One to finance dividends and return of stated capital	(248)	(318)
Excess of assets over liabilities - ending	4,458	4,273

16. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One Networks contributions to the DC Plan for the year ended December 31, 2017 were less than $1 million (2016 - less than $1 million). At December 31, 2017 and 2016, Company contributions payable included in accrued liabilities on the Balance Sheets were not significant.

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 - $108 million) were based on an actuarial valuation effective

December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

At December 31, 2017, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,258 million (2016 - $7,774 million). The fair value of pension plan assets available for these benefits was $7,277 million (2016 - $6,874 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2017, the Transmission Business charged $20 million (2016 - $19 million) of post-retirement and post-employment benefit costs to operation, and capitalized $35 million (2016 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2017 were $18 million (2016 - $19 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $89 million (2016 - increased by $1 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Accrued liabilities	25	26
Post-retirement and post-employment benefit liability	646	697
Net unfunded status	671	723

17. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	77	8	85
Interest accretion	3	—	3
Expenditures	(6)	(2)	(8)
Revaluation adjustment	(1)	(1)	(2)
Environmental liabilities - ending	73	5	78
Less: current portion	(8)	(1)	(9)
	65	4	69

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	71	11	82
Interest accretion	4	—	4
Expenditures	(3)	(4)	(7)
Revaluation adjustment	5	1	6
Environmental liabilities - ending	77	8	85
Less: current portion	(8)	(2)	(10)
	69	6	75

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	78	5	83
Less: discounting environmental liabilities to present value	(5)	—	(5)
Discounted environmental liabilities	73	5	78

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	85	9	94
Less: discounting environmental liabilities to present value	(8)	(1)	(9)
Discounted environmental liabilities	77	8	85

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	9
2019	12
2020	12
2021	16
2022	18
Thereafter	16
	83

The Transmission Business records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 3.8%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' environmental liabilities represent management’s best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company’s current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One’s PCBs have to be disposed of by the end of 2024, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $78 million (2016 - $85 million). These expenditures are expected to be incurred over the period from 2018 to 2024. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2017 to reduce the PCB environmental liability by $1 million (2016 - increase by $5 million).

Land Assessment and Remediation

The Transmission Business' best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $5 million (2016 - $9 million). These expenditures are expected to be incurred over the period from 2018 to 2022. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2017 to reduce the land assessment and remediation environmental liability by $1 million (2016 - increase by $1 million).

18. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2017, Hydro One Networks had recorded asset retirement obligations of $4 million (2016 - $4 million) related to its Transmission Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

19. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2017 and 2016, Hydro One Networks had 207,577,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2017, Hydro One Networks declared common share dividends in the amount of $2 million (2016 – $2 million) and made a return of stated capital of $509 million (2016 – $609 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends and return of stated capital was $248 million (2016 – $318 million).

20. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015,1,761,152 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by the Transmission Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 608,626 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by the Transmission Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Transmission Business was $49 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2017, 179,175 common shares were granted under the Share Grant Plans (2016 - $nil) to eligible employees of Hydro One Networks and allocated to the Transmission Business. Total stock-based compensation recognized by the Transmission Business during 2017 was $8 million (2016 - $9 million) and was recorded as a regulatory asset.

A summary of the Transmission Business' share grant activity under the Share Grant Plans during 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,332,878	$20.50
Vested and issued[1]	(179,175)	—
Forfeited	(64,777)	$20.50
Share grants outstanding - ending	2,088,926	$20.50

[1] On April 1, 2017, Hydro One Limited issued from treasury 179,175 common shares to eligible Hydro One Networks employees, which were allocated to the Transmission Business, in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,369,778	$20.50
Forfeited[1]	(36,900)	$20.50
Share grants outstanding - ending	2,332,878	$20.50

[1]Includes shares forfeited as well as shares transferred corresponding to transfer of employees between affiliate companies.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one Hydro One Limited common share and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

During 2017 and 2016, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	38,416	7,958
DSUs granted	32,492	30,458
DSUs outstanding - ending	70,908	38,416

For the year ended December 31, 2017, an expense of $1 million (2016 - $1 million) was recognized in earnings by the Transmission Business with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $2 million (2016 - $1 million), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

During 2017 and 2016, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	27,970	—
Paid	(629)	—
DSUs outstanding - ending	27,341	—

For the year ended December 31, 2017, an expense of $1 million (2016 - $nil) was recognized in earnings by the Transmission Business with respect to the Management DSU Plan. At December 31, 2017, a liability of $1 million (2016 - $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP for the Transmission Business were $1 million (2016 - $1 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other stock-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2017 and 2016, LTIP awards granted by Hydro One Limited that related to Hydro One Networks' Transmission Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	84,952	—	96,083	—
Units granted	119,062	86,487	97,341	97,618
Units vested	(291)	—	(6,983)	—
Units forfeited	(23,797)	(1,535)	(22,050)	(1,535)
Units outstanding - ending	179,926	84,952	164,391	96,083

The grant date total fair value of the awards granted in 2017 was $5 million (2016 - $5 million). The compensation expense related to these awards recognized by the Transmission Business during 2017 was $2 million (2016 - $1 million).

21. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province.

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Transmission services – amounts received[1]	1,450	1,510
OPG	Revenues related to provision of construction and equipment maintenance services	2	4
	Costs related to the purchase of services	1	1
OEB	OEB fees	3	4
Hydro One Limited and its subsidiaries	Revenues for services provided	9	3
	Services received - costs expensed	19	20
	Services received - costs capitalized	—	12
	Interest expense on long-term debt	259	248
	Interest expense on inter-company demand facility	8	5
	Payments to finance dividends and return of stated capital	248	318
	Stock-based compensation costs	10	10

[1] Consistent with the Company's revenue recognition policy, the Transmission Business recognized revenues of $1,489 million in 2017 (2016 – $1,512 million).

The amounts due to and from related parties at December 31, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017	2016
Inter-company demand facility	(1,071)	(213)
Due from related parties	158	134
Due to related parties	(179)	(124)
Accrued interest	(58)	(62)
Long-term inter-company payable	(18)	(11)
Long-term debt, including current portion	(5,500)	(5,908)

22. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	(9)	(7)
Due from related parties	(24)	(15)
Materials and supplies	1	(1)
Other assets	(24)	(1)
Accounts payable	(9)	19
Accrued liabilities	(40)	(6)
Due to related parties	55	65
Accrued interest	(4)	4
Long-term accounts payable and other liabilities	(3)	2
Post-retirement and post-employment benefit liability	38	34
	(19)	94

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(928)	(965)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	11	10
Cash outflow for capital expenditures – property, plant and equipment	(917)	(955)

The following table reconciles investments in intangible assets and the amounts presented in the Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(26)	(22)
Net change in accruals included in capital investments in intangible assets	2	—
Cash outflow for capital expenditures – intangible assets	(24)	(22)

Capital Contributions

Hydro One Networks enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One Networks based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One Networks. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One Networks will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2017, capital contributions from these reassessments totalled $9 million (2016 - $21 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	263	244
Income taxes paid	60	14

23. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

24. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

25. SUBSEQUENT EVENTS

Payments to Finance Dividends and Return of Stated Capital

On February 12, 2018, Hydro One Networks declared common share dividends in the amount of $1 million, and a return of stated capital in the amount of $131 million was approved. The amount allocated to the Transmission Business to finance these payments was $51 million.

RATING AGENCY REPORTS

This Exhibit includes copies of the most recent rating agency reports performed by Dominion Bond Rating Service ("DBRS"), Moody's Investor Service, and Standard & Poor's.

- Attachment 1: DBRS Report, dated: April 9, 2018
- Attachment 2: DBRS Rating Confirmation, dated: April 9, 2018
- Attachment 3: Moody's Investor Service, Credit Opinion, dated: June 29, 2018
- Attachment 4: Moody's Investor Service, Rating Action, dated: June 20, 2018
- Attachment 5: Standard & Poor's Research, dated: September 13, 2018
- Attachment 6: Standard & Poor's Research, dated: December 10, 2018

Hydro One Inc.

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DBRS
Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 9, 2018, DBRS Limited (DBRS) confirmed the Issuer Rating and the Senior Unsecured Debentures rating of Hydro One Inc. (HOI or the Company) at A (high) and the Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmations reflect the Company's relatively low risk business profile supported by a transparent regulatory framework, a strong franchise of electricity power transmission and distribution services and a reasonable financial profile sustained by predictable earnings and cash flow. The Stable trends assume that the regulatory regime will continue to remain supportive, allowing the Company to earn a fair rate of return while recovering costs on a timely basis. DBRS rates HOI as a stand-alone entity and does not assume any credit support from its owner, Hydro One Limited (HOL; not rated by DBRS), which is approximately 47% owned by the Province of Ontario (the Province; rated AA (low) with a Stable trend by DBRS). The Company's transmission business (approximately 61% of 2017 earnings before interest and tax (EBIT)) owns and operates approximately 98% of the transmission network in the Province while the distribution business (approximately 39% of 2017 EBIT) serves nearly 25% of the Province's customers.

In July 2017, HOL announced that it will acquire Avista Corporation (Avista), a regulated electric and gas utilities holding company operating in the U.S. Pacific Northwest, for an all-cash purchase price of approximately USD 5.3 billion ($6.7 billion), including the assumption of approximately USD 1.9 billion ($2.7 billion) of debt. Avista is expected to continue operating as a stand-alone utility following the closing of the transaction in the second half of 2018. DBRS believes that should the acquisition be financed as contemplated in the announcement, it will have no impact on HOI's credit profile as no debt is proposed to be issued at HOI. Please refer to DBRS's press release, "DBRS Comments on Hydro One Limited Acquiring Avista Corporation" dated July 20, 2017, for more details.

HOI's transmission and distribution businesses currently operate under cost-of-service (COS) regulation. HOI's transmission business is expected to file a four-year rate application under a Custom Incentive Rate-Setting (CIR) approach for 2019-2022 in Q2 2018. In March 2017, Hydro One Networks Inc. (HONI) filed an application for 2018-2022 distribution rates under CIR and a decision is expected in Q2 2018. DBRS does not expect HOI's transition to a CIR model to have a material impact on the Company's credit profile as it provides greater clarity with respect to HOI's ability to recover high and variable capital expenditure (capex) requirements. Additionally, HOI is appealing a October 2017 Ontario Energy Board (OEB) decision that the tax savings from the net deferred tax asset recorded by the Company's transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to the federal and provincial tax regime in 2016, should not accrue entirely to HOI's shareholders and that a portion should be shared with ratepayers. HOI has estimated that should the decision be upheld, there could be a one-time decrease in net income of approximately $885 million and an annual reduction in operating cash flow

Continued on P.2

Financial Information

(CAD millions where applicable)	For the year ended December 31 2017	2016	2015	2014	2013
Cash flow/Total debt	13.2%	13.6%	13.3%	15.5%	15.3%
Total debt in capital structure 1	53.3%	53.0%	51.1%	53.0%	55.2%
DBRS adjusted debt in capital structure 1, 2	55.6%	57.3%	55.5%	53.0%	55.3%
EBIT gross interest coverage (times) 1	2.65	2.77	2.74	2.83	2.94

1 Includes operating leases. 2 DBRS adjusted, excludes deferred tax assets 2017: $885 million.

Issuer Description

HOI is the largest electricity transmission and distribution company in Ontario. The Company owns and operates over 30,000 circuit kilometres (km) of high-voltage transmission lines and approximately 123,000 circuit km of primary low-voltage distribution lines.

Rating Considerations

by around $50 million to $60 million. A decision is expected by Q2 2018, and DBRS will review the outcome of the appeal to assess its impact on the credit profile of the Company.

DBRS notes that HOI's credit metrics continue to be pressured because of the incremental debt used to fund free cash flow deficits resulting from high capex and dividends. HOI's capex program is expected to total approximately $10.0 billion for the 2018-2022 term (transmission: $6.4 billion; distribution: $3.6 billion) largely to refurbish and replace aging infrastructure. However, as projects are placed in service and added to the Company's rate base, incremental cash flows should help ease the pressure on metrics. HOI's dividend payout ratio is expected to remain high in order to meet HOL's dividend objectives to pay out approximately 70% to 80% of its consolidated net income. HOI's ratings could be impacted should its cash flow-to-debt ratio weaken below 13% and its DBRS adjusted debt-to-capital ratio exceed 60% on a sustained basis. HOI expects any potential acquisitions of unregulated businesses to be carried out at the HOL level. DBRS believes that acquisitions by HOI of regulated utility assets in less supportive regulatory regimes or acquisition of regulated assets with some exposure to unregulated operations could weaken the business profile of the Company and have an impact on the current ratings.

Rating Considerations

Strengths

1. Reasonable regulatory environment
HOI's earnings are contributed by its low-risk regulated transmission and distribution businesses that operate under a reasonable regulatory framework. The regulatory regime under the OEB permits HOI a reasonable opportunity to recover operating and capital costs and earn the approved rates of return. The Company's deemed capital structure (debt-to-equity of 60%:40%) has remained unchanged for several years. DBRS views the utility regulatory framework in Ontario as transparent and supportive for regulated transmission and distribution operators.

2. Extensive franchise area
HOI owns the largest transmission and distribution businesses in Ontario. The Company operates approximately 98% of the Province's transmission infrastructure based on revenues approved by the OEB, is connected to more than 70 local distribution companies (including HOI's own distribution business) and certain large directly connected industrial customers. The Company's transmission system is also interconnected to systems in Manitoba, Michigan, Minnesota, New York and Québec through the use of interties. Load growth is expected to be modest and in line with economic growth in the Province. The distribution business spans approximately 75% of the Province, serving over 1.3 million customers, or approximately 25% of the total customers in Ontario.

3. Reasonable financial profile
HOI continues to maintain a reasonably healthy balance sheet. Although the cash flow-to-debt metrics have been pressured in recent years, overall key credit metrics have remained reasonable for the current rating category (DBRS-adjusted debt-to-capital ratio at 55.6%, EBIT interest coverage at 2.65 times (x) and cash flow-to-debt at 13.2% for 2017).

Challenges

1. High level of planned capex
The Company is currently in the midst of an aggressive buildout program that will continue over the next several years which could pressure credit metrics. Capex was approximately $1.6 billion for 2017 (approximately $968 million for transmission and approximately $588 million for distribution), with a plan for approximately $10.1 billion in the next five years based on HOI's current regulatory filings.

2. High dividend payouts
Compared with pre-2015 levels, DBRS expects the Company to pay out a higher portion of its earnings as dividends to support HOL's dividend policy (payout approximately 70% to 80% of consolidated net income). DBRS expects the Company's dividend payout ratio to remain high in order to meet HOL's dividend objectives, and consequently, HOI will need to access significant external funding to finance the potentially sizable free cash flow deficits because of the dividends and capex commitments expected over the medium term.

3. Earnings sensitive to volume and costs
Earnings and cash flows for electricity distribution companies are partially dependent on the volume of electricity sold. Weather patterns, seasonality and economic conditions directly affect the volume of electricity sold and, therefore, earnings. The OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, earnings of these businesses could be adversely affected. Furthermore, current revenue requirements are approved based on cost assumptions that could materially differ from actual costs. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in costs. However, this risk is expected to be gradually mitigated as the OEB implemented the new distribution rate design for all local distribution companies beginning in 2016, and HOI is allowed to phase in a higher fixed monthly rate and lower volumetric rate for its residential customers over the next eight years. Consequently, by 2023, all residential customers will be charged a fully fixed monthly fee for distribution services.

Earnings and Outlook

(CAD millions where applicable)	2017	2016	2015	2014	2013
	For the year ended December 31				
Net Revenue	3,072	3,075	3,079	3,129	3,054
EBITDA	2,058	2,016	1,949	1,985	1,905
EBIT	1,248	1,247	1,192	1,263	1,229
Gross interest expense	468	448	433	444	416
Earning before taxes	837	855	814	874	858
Income taxes	(120)	(131)	(113)	(86)	(106)
Minority interest	(6)	(6)	(10)	2	0
Net income before non-recurring items	711	718	691	790	752
Non-recurring items 1	0	12	1	(41)	51
Reported net income	711	730	692	749	803
Return on equity	9.1%	9.7%	9.0%	10.3%	10.6%
Transmission rate base (CAD billions) 2	11.25	10.78	10.17	9.93	9.35
Distribution rate base (CAD billions)	7.39	7.06	6.59	5.03	5.03
Allowed ROE - Transmission (Hydro One Network)	8.78%	9.19%	9.30%	9.36%	8.93%
Allowed ROE - Transmission (B2M LP)	8.78%	9.19%	9.30%	N/A	N/A
Allowed ROE - Transmission (Hydro One Ste. Marie LP)	9.19%	9.19%	N/A	N/A	N/A
Allowed ROE - Distribution	8.78%	9.19%	9.30%	9.66%	9.66%
Deemed Equity (Transmission & Distribution)	40%	40%	40%	40%	40%

1 DBRS adjustment of $48 million for customer service recovery project costs in 2014 and $43 million property tax recovery in 2013.
2 Includes Hydro One Networks, B2M LP and Hydro One Ste. Marie LP.

2017 Summary

- HOI's earnings are relatively stable and are supported by a reasonable regulatory environment, extensive franchise area and a diverse customer base that is growing at a steady rate.
- The Company's net earnings were slightly lower in 2017, compared with 2016, resulting from lower electricity consumption as a result of milder weather, lower return on equity (ROE) of 8.78% (down from 9.19%) and modestly higher operating costs.

2018 Outlook

- EBIT for 2018 is expected to be modestly higher because of the higher allowed ROE approved by the OEB (9.00% in 2018, versus 8.78% in 2017) and a higher rate base for both the transmission and distribution segments.

Financial Profile

(CAD millions where applicable)	2017	2016	2015	2014	2013
	For the year ended December 31				
Net income before non-recurring items	711	718	691	790	752
Depreciation & amortization	720	679	667	641	597
Deferred income taxes and other	88	119	(3)	(51)	41
Cash flow from operations	**1,519**	**1,516**	**1,355**	**1,380**	**1,390**
Dividends	(550)	(611)	(888)	(287)	(218)
Capital expenditures	(1,527)	(1,634)	(1,569)	(1,504)	(1,387)
Free cash flow (bef. working cap. changes)	**(558)**	**(729)**	**(1,102)**	**(411)**	**(215)**
Changes in non-cash work. capital	63	168	187	(55)	11
Changes in regulatory assets	112	(16)	(3)	(69)	3
Deferred income tax asset 1	0	0	(2,798)	0	0
Net Free Cash Flow	**(383)**	**(577)**	**(3,716)**	**(535)**	**(201)**
Acquisitions	0	(224)	(143)	(66)	0
Short-term investments	0	0	0	0	0
Long-term investments 2	0	0	0	250	0
Amount to be financed	**(383)**	**(801)**	**(3,859)**	**(351)**	**(201)**
Net equity change	0	0	2,600	72	0
Net debt change 3	344	776	1,254	(177)	574
Other	(9)	(16)	(6)	(9)	(3)
Change in cash	**(48)**	**(41)**	**(11)**	**(465)**	**370**
Total debt	11,482	11,149	10,198	8,927	9,088
Cash and equivalents	0	48	89	100	565
Cash flow-to-total debt	13.2%	13.6%	13.3%	15.5%	15.3%
Total debt in capital structure 4	53.3%	53.0%	51.1%	53.0%	55.2%
DBRS adjusted debt in capital structure 5	55.6%	57.3%	55.5%	53.0%	55.3%
EBIT gross interest coverage (times)	2.67	2.78	2.75	2.84	2.95
Debt-to-rate base	61.6%	62.5%	60.8%	59.7%	63.2%
Dividend payout ratio 6	77.4%	85.1%	128.6%	36.3%	29.0%

1 2015 deferred income tax asset recorded on revaluation of assets upon switching from PILs regime to the federal tax regime. 2 Proceeds of $250 million Province of Ontario FRNs redeemed in 2014. 3 Includes preferred shares of $486 million in 2017 that DBRS has treated as debt as it will be redeemed in 2018. 4 Includes operating leases. 5 Excludes deferred income tax assets 2017: $885 million. 6 2015 dividends includes dividends paid to the Province for recapitalization pre-IPO.

2017 Summary

- Overall, HOI's key credit metrics remained reasonable for the current rating category.
- Operating cash flow was comparable to 2016. The Company continued to generate a free cash flow deficit due to its capex program and dividends to HOL.
- As a result of HOI's switch from the payment in lieu of taxes regime to the federal tax regime in 2015, HOI recorded a deferred tax asset representing the revaluation of the tax basis of the Company's fixed assets at their fair market value and recognition of eligible capex. In its decision of the Company's 2017-2018 transmission rates application, the OEB approved for the tax savings resulting from the deferred tax asset to be allocated between HOI and ratepayers. This would result in the impairment of the deferred tax asset by $885 million (non-cash) and a decrease to the Company's annual operating cash flow by around $50 to $60 million.
  - HOI has filed a motion to review and vary this decision with the OEB. The Company has also filed an appeal with the Ontario Divisional Court.
  - DBRS has reduced the potential impairment of $885 million from HOI's equity in calculating the debt-to-capital ratio.

2018 Outlook

- DBRS expects free cash flow deficits to persist in the medium term as the Company has planned capex averaging approximately $2.0 billion annually during the 2018-2022 term (approximately 64% for transmission and 36% for distribution) largely to sustain HOI's aging power systems and also to build critical infrastructure to meet growth in the customer base.
- DBRS expects the Company to support HOL's dividend policy (annual dividends of approximately 70% to 80% of consolidated net income) to the extent that such dividend payouts maintain HOI's regulatory capital structure. Consequently, DBRS expects the Company to pay a higher portion of its earnings as dividends compared with pre-2015 levels.
- Cash flow from operations is expected to grow over the medium to long term as capital projects are placed into service and included in the rate base. As a result, DBRS expects key credit metrics to gradually improve and remain reasonable for the current rating.

Debt and Liquidity

(CAD millions - as at December 31, 2017)	Amount	Draw/LOCs	Available	Maturity
Cash & Cash Equivalents	-		-	
Revolving standby credit facility	2,300	926	1,374	June 2022
Total	**2,300**	**926**	**1,374**	

- The Company's liquidity profile remains reasonable and adequate for its normal operating requirements.
- The Company has a revolving credit facility of $2.3 billion maturing in June 2022. The Company's $1.5 billion commercial paper program is backstopped by this facility. As of December 31, 2017, approximately $926 million of commercial paper was outstanding.

Long-term Debt Maturities

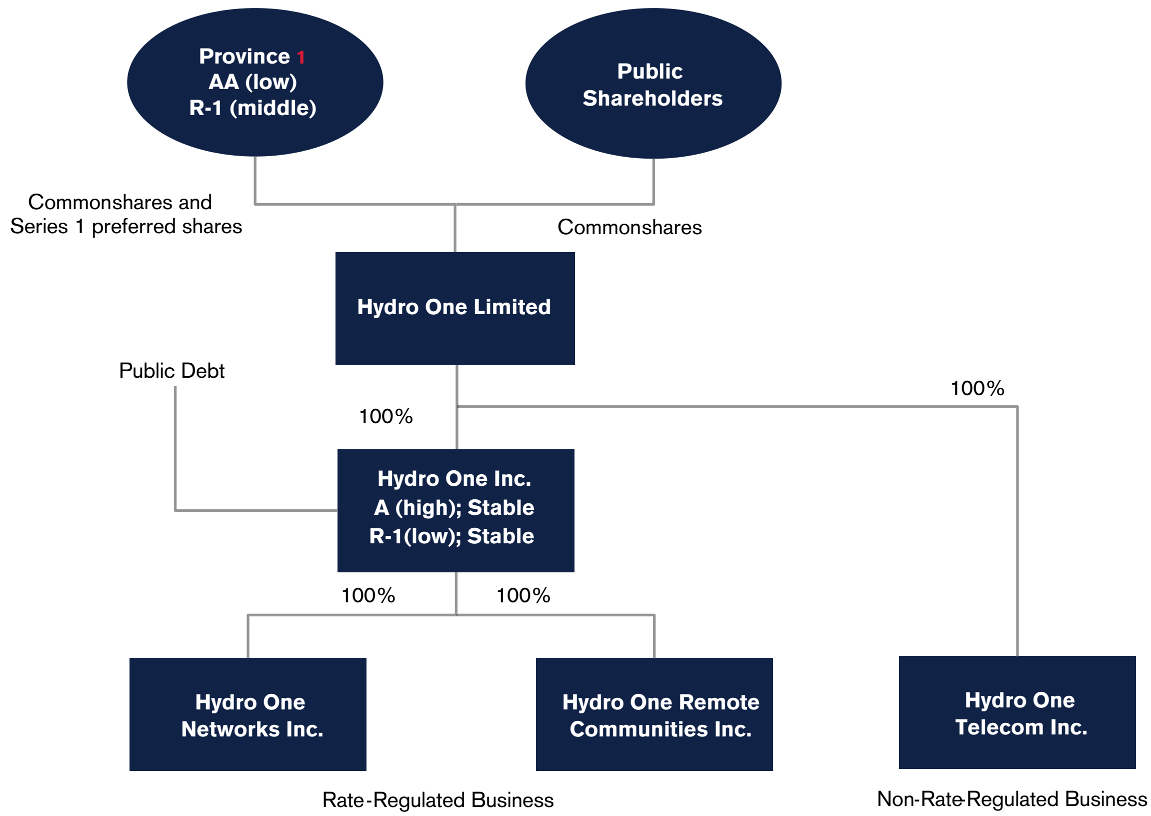
(CAD millions - as at December 31, 2017)	2018	2019	2020	2021	2022	Thereafter	Total
Principal Repayments	752	731	653	503	604	6,826	10,069
% of Total	**7%**	**7%**	**6%**	**5%**	**6%**	**68%**	**100%**

- HOI's refinancing risk remains manageable with maturities well spread-out.
- HOI has adequate access to debt markets and access to the equity market through its parent, HOL. HOI filed a new $4.0 billion shelf prospectus in March 2018.
- HOI has covenants limiting the permissible debt to 75% of its total capitalization and limiting the ability to sell assets and impose negative pledge provisions, subject to customary exceptions. As of December 31, 2017, the Company was in compliance with all of these covenants and limitations.

Major Projects and Acquisitions

- Major transmission development projects include: (1) the $267 million Clarington Transmission Station Project to install additional autotransformer capacity in the east Greater Toronto Area, expected to be in service in 2018; (2) the $57 million Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region, expected to be in service by 2018; (3) the $350 million Northwest Ontario Bulk Transmission Line Project, a new transmission line in the west Thunder Bay area, expected to be in service by 2024; and (4) the $157 million East-West Tie Station Expansion Project, expected to be in service in 2021.
- In August 2016, HOI reached an agreement to acquire Orillia Power Distribution Corporation, an electricity distribution company located in Simcoe County, Ontario, for approximately $41 million, including the assumption of $15 million in outstanding indebtedness and regulatory liabilities and subject to other closing adjustments. Closing is subject to OEB approval.
- In October 2016, the Company completed the acquisition of Hydro One Sault Ste. Marie LP (HOSSM, formerly Great Lakes Power Transmission LP) for $226 million in cash and the assumption of approximately $150 million in debt. The asset had a rate base of approximately $218 million in 2017, with 15 transmission stations and 560 km of high and medium voltage 44-230 kilovolt transmission lines covering a service area of approximately 12,000 square km.

Simplified Ownership Structure



Notes:
1 As of December 31, 2017, the Province owned approximately 47.4% of Hydro One Limited's outstanding common shares and 100% of the outstanding Series 1 preferred shares.

- In November 2015, HOL and the Province completed an initial public offering on the Toronto Stock Exchange of approximately 89.3 million common shares of HOL. In April 2016, the Province completed a secondary offering of 83.3 million common shares of HOL.
- HOI is 100% owned by HOL, which is in turn 47.4% owned by the Province, with the remaining held by public shareholders.
- HOI owns two regulated utilities, Hydro One Networks Inc. and Hydro One Remote Communities Inc.
- Hydro One Networks Inc. carries on rate-regulated transmission and distribution businesses.
- Hydro One Remote Communities Inc. generates and supplies electricity to remote communities in northern Ontario.

Regulation

Regulatory Overview

- HOI has a good track record of prudently managing its regulatory risk. The Company's transmission and distribution businesses are licensed and regulated by the OEB. DBRS has assessed the regulatory environment to be reasonable. (Refer to the Assessment of HOI's Regulatory Environment on page 8).
- The OEB uses a deemed debt-to-common equity structure of 60% to 40% for both the transmission and distribution business segments.
- HOI's distribution and transmission operations both currently operate under COS, but will be transitioning to CIR in 2018 for distribution and 2019 for transmission.
- Under both COS and CIR, HOI can charge rates that allow it to recover the costs of providing its services and earn an allowed ROE. CIR encourages the Company to improve efficiency over time, resulting in lower costs to provide the same service.

Transmission

- In May 2016, HOI submitted its 2017-2018 transmission rate application based on the COS model. The application sought approval of a revenue requirement of $1,505 million for 2017, and $1,586 million for 2018, reflecting a required rate base of $10,554 million for 2017, and $11,226 million for 2018. In December 2016, HOI filed an application to update its revenue requirement to $1,487 million for 2017, and to $1,558 million for 2018, excluding the Bruce to Milton LP (B2M LP) transmission network, based on OEB's updated 2017 cost of capital parameters. In November 2017, the OEB approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. In December 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amounts based on updated cost of capital parameters.
- Hydro One Networks is expected to file a four-year rate application under a CIR approach for 2019-2022 in Q2 2018.
- In December 2016, HOSSM (Great Lakes Power) filed an application seeking approval of a revenue requirement of $41 million for 2017. In September 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. The 2016 approved revenue requirement of $41 million remained in effect in 2017.

Distribution

- The Company's distribution business continues to operate under a COS framework in 2018.
- In December 2013, the Company filed a five-year distribution custom rate application (for 2015-2019) with the OEB. The OEB did not consider the Company's custom COS application as sufficiently aligned with its performance-based framework for setting rates and approved rates for a shorter three-year period (2015-2017) based on the COS methodology with the allowed ROE to be updated annually. However, the OEB approved the rate base and capex for 2015-2017, as applied for by HOI.
- In March 2015, the OEB approved the Company's distribution rates revenue requirement of $1,326 million for 2015; $1,430 million for 2016; and $1,486 million for 2017. In January 2016, the OEB revised the revenue requirement for 2016 to $1,410 million based on an updated 2016 allowed ROE of 9.19%. In December 2016, the OEB revised the revenue requirement for 2017 to $1,415 million based on an updated 2017 allowed ROE of 8.78%.
- In March 2017, Hydro One Networks filed a distribution application for 2018–2022 rates based on the CIR approach. The application sought approval of a revenue requirement of $1,505 million for 2018, reflecting an increase of 3.5% over 2017, and rate base of $7,672 million. The revenue requirement for 2018 is determined using a COS forward test year approach. To establish the annual revenue requirements from 2019 to 2022, HOI has proposed a revenue cap index that allows for an annual increase in distribution rates based on an inflation, a productivity and a custom capital factor to recover incremental revenue associated with capex. The Company has also proposed for equity thickness to remain unchanged at 40% and the ROE of 9.00%.
- In November 2017, HOI filed a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. In December 2017, the OEB denied the request and set the interim rates with no adjustments. In December 2017, HOI updated its application with updated cost of capital parameters and inflation factor for 2018, and reduced the 2018 OM&A forecast and 2018-2022 capital forecasts.

Regulation

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows HOI's transmission and distribution business to have a deemed equity of 40%, which has been consistent historically.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	The cost of capital parameters are updated annually by the OEB. The OEB has set ROE for the transmission and distribution business at 9.00% for 2018 (8.78% for 2017).
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk, as HOI is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to ratepayers and HOI collects the payments from its customers on a monthly basis.
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the OEB and added to the rate base after project completion. In addition, the OEB can approve rate riders to allow for the recovery or disposition of specific regulatory accounts over specified time frames.
5. COS versus IRM	Excellent **Good** Satisfactory Below Average Poor	HOI's distribution business has opted to use the five-year CIR option. However, the distribution business has been allowed to operate under a COS rate-setting methodology by the OEB until 2018. Transmission rates are based on COS application rate orders approved by the OEB every two years, but will also be transitioning to CIR beginning 2019.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	After years of a relatively stable political and regulatory environment, the utility sector in Ontario could face growing challenges. As generation costs potentially rise above and ultimately test the political ceiling (10% increase in the total bill annually), it may be difficult for the utilities to pass costs onto ratepayers.
7. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	HOI has a limited history of stranded costs. Most prudently incurred or budgeted capex are approved by the OEB.
8. Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	From 2002 to 2005, because of rising rates during Ontario's experimental utility deregulation phase, a distribution rate freeze was imposed. There have been no subsequent province-wide rate freezes.

Hydro One Inc.

Balance Sheet

(CAD millions)

	December 31				December 31		
	2017	2016	2015		2017	2016	2015
Assets				**Liabilities & Equity**			
Cash & equivalents	0	48	89	S.T. borrowings	929	469	1,491
Accounts receivable	635	833	772	Accounts payable	736	828	743
Inventories	18	19	21	Current portion L.T.D.	752	602	500
Prepaid expenses & other	525	302	263	Other current liab.	499	358	247
Total Current Assets	**1,178**	**1,202**	**1,145**	**Total Current Liab.**	**2,916**	**2,257**	**2,981**
Net fixed assets	19,871	19,068	17,893	Long-term debt	9,315	10,078	8,207
Future income tax assets	954	1,213	1,610	Deferred income taxes	70	60	206
Goodwill & intangibles	694	676	499	Pension and other liabilities	2,665	2,714	2,687
Regulatory assets	3,049	3,145	3,015	Regulatory liabilities	128	209	236
Investments & others	5	6	7	L.T. Payables & Other L.T. liab.	69	51	27
				Minority interest	72	72	75
				Preferred Shares	486	0	0
				Common equity	4,856	5,391	6,000
				Retained earnings	5,183	4,487	3,759
				Accumulated OCI	(9)	(9)	(9)
Total Assets	**25,751**	**25,310**	**24,169**	**Total Liab & SE**	**25,751**	**25,310**	**24,169**

Balance Sheet & Liquidity & Capital Ratios	For the year ended December 31				
	2017	2016	2015	2014	2013
Current ratio	0.40	0.53	0.38	0.85	1.03
Cash flow/Total debt	13.2%	13.6%	13.3%	15.5%	15.3%
Total debt in capital structure 1	53.3%	53.0%	51.1%	53.0%	55.2%
(Cash flow-dividends)/Capex (times)	0.63	0.55	0.30	0.73	0.84
Dividend payout ratio 2	77.4%	85.1%	128.6%	36.3%	29.0%
Coverage Ratios (times)					
EBIT gross interest coverage	2.67	2.78	2.75	2.84	2.95
EBITDA gross interest coverage	4.40	4.50	4.50	4.47	4.58
Fixed-charges coverage	2.65	2.77	2.74	2.83	2.94
Profitability Ratios					
EBITDA margin	67.0%	65.6%	63.3%	63.4%	62.4%
EBIT margin	40.6%	40.6%	38.7%	40.4%	40.2%
Profit margin	23.1%	23.4%	22.4%	25.2%	24.6%
Return on equity	9.1%	9.7%	9.0%	10.3%	10.6%
Return on capital	4.8%	5.1%	5.1%	5.5%	5.6%

1 Including operating leases. 2 2015 dividends includes dividends paid to Province for recapitalization.

Rating History

	Current	2017	2016	2015	2014	2013	2012	2011
Issuer Rating	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Previous Action

- DBRS Confirms Ratings of Hydro One Inc. at A (high) and R-1 (low), April 7, 2017.

Previous Report

- Hydro One Inc.: Rating Report, April 13, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings Limited (England and Wales) (CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings México, Institución Calificadora de Valores S.A. de C.V. (Mexico)(CRA, NRSRO affiliate, DRO affiliate). Please note that DBRS Ratings Limited was registered as an NRSRO affiliate on July 14, 2017. For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/225752/highlights.pdf.

Date of Release: April 9, 2018

DBRS Confirms Ratings of Hydro One Inc., Stable Trends

Bloomberg: DBRS Confirms Ratings of Hydro One Inc., Stable Trends
Industry Group: Corporate Finance
Sub-Industry: Energy
Region: Canada

DBRS Limited (DBRS) confirmed the Issuer Rating and the Senior Unsecured Debentures rating of Hydro One Inc. (HOI or the Company) at A (high) and the Commercial Paper rating at R-1 (low). All trends are Stable. The rating confirmations reflect the Company's relatively low risk business profile supported by a transparent regulatory framework, a strong franchise of electricity power transmission and distribution services and a reasonable financial profile sustained by predictable earnings and cash flow. The Stable trends assume that the regulatory regime will continue to remain supportive, allowing the Company to earn a fair rate of return while recovering costs on a timely basis. DBRS rates HOI as a stand-alone entity and does not assume any credit support from its owner, Hydro One Limited (HOL; not rated by DBRS), which is approximately 47% owned by the Province of Ontario (the Province; rated AA (low) with a Stable trend by DBRS). The Company's transmission business (approximately 61% of 2017 EBIT) owns and operates approximately 98% of the transmission network in the Province while the distribution business (approximately 39% of 2017 EBIT) serves nearly 25% of the Province's customers.

In July 2017, HOL announced that it will acquire Avista Corporation (Avista), a regulated electric and gas utilities holding company operating in the U.S. Pacific Northwest, for an all-cash purchase price of approximately USD 5.3 billion ($6.7 billion), including the assumption of approximately USD 1.9 billion ($2.7 billion) of debt. Avista is expected to continue operating as a stand-alone utility following the closing of the transaction in the second half of 2018. DBRS believes that should the acquisition be financed as contemplated in the announcement, it will have no impact on HOI's credit profile as no debt is proposed to be issued at HOI. Please refer to DBRS's press release, "DBRS Comments on Hydro One Limited Acquiring Avista Corporation" dated July 20, 2017, for more details.

HOI's transmission and distribution businesses currently operate under cost-of-service regulation. HOI's transmission business is expected to file a four-year rate application under a Custom Incentive Rate-Setting (CIR) approach for 2019-2023 in Q2 2018. In March 2017, Hydro One Networks Inc. filed an application for 2018-2022 distribution rates under CIR and a decision is expected in Q2 2018. DBRS does not expect HOI's transition to a CIR model to have a material impact on the Company's credit profile as it provides greater clarity with respect to HOI's ability to recover high and variable capital expenditure (capex) requirements. Additionally, HOI is appealing a October 2017 Ontario Energy Board decision that the tax savings from the net deferred tax asset recorded by the Company's transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to the federal and provincial tax regime in 2016, should not accrue entirely to HOI's shareholders and that a portion should be shared with ratepayers. HOI has estimated that should the decision be upheld, there could be a one-time decrease in net income of approximately $885 million and an annual reduction in operating cash flow by around $50 million to $60 million. A decision is expected by Q2 2018, and DBRS will review the outcome of the appeal to assess its impact on the credit profile of the Company.

DBRS notes that HOI's credit metrics continue to be pressured because of the incremental debt used to fund free cash flow deficits resulting from high capex and dividends. HOI's capex program is expected to total approximately $10.0

billion for the 2018-2022 term (transmission: $6.4 billion; distribution: $3.6 billion) largely to refurbish and replace aging infrastructure. However, as projects are placed in service and added to the Company's rate base, incremental cash flows should help ease the pressure on metrics. HOI's dividend payout ratio is expected to remain high in order to meet HOL's dividend objectives to pay out approximately 70% to 80% of its consolidated net income. HOI's ratings could be impacted should its cash flow-to-debt ratio weaken below 13% and its DBRS adjusted debt-to-capital ratio exceed 60% on a sustained basis. HOI expects any potential acquisitions of unregulated businesses to be carried out at the HOL level. DBRS believes that acquisitions by HOI of regulated utility assets in less supportive regulatory regimes or acquisitions of regulated assets with some exposure to unregulated operations could weaken the business profile of the Company and have an impact on the current ratings.

Notes:
All figures are in Canadian dollars unless otherwise noted.

The principal methodologies are Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry Methodology (September 2017) and DBRS Criteria: Commercial Paper Liquidity Support for Non-Bank Issuers (April 2018), which can be found on dbrs.com under Methodologies.

The related regulatory disclosures pursuant to the National Instrument 25-101 *Designated Rating Organizations* are hereby incorporated by reference and can be found by clicking on the link under Related Documents or by contacting us at info@dbrs.com.

The rated entity or its related entities did participate in the rating process for this rating action. DBRS had access to the accounts and other relevant internal documents of the rated entity or its related entities in connection with this rating action.

DBRS will publish a full report shortly that will provide additional analytical detail on this rating action. If you are interested in receiving this report, contact us at info@dbrs.com.

For more information on this credit or on this industry, visit www.dbrs.com or contact us at info@dbrs.com.

Issuer	Debt Rated	Rating Action	Rating	Trend
Hydro One Inc.	Issuer Rating	Confirmed	A (high)	Stable
Hydro One Inc.	Senior Unsecured Debentures	Confirmed	A (high)	Stable
Hydro One Inc.	Commercial Paper	Confirmed	R-1 (low)	Stable

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MOODY'S
INVESTORS SERVICE

CREDIT OPINION
29 June 2018

Update

Rate this Research

RATINGS

Hydro One Inc.

Domicile	Toronto, Ontario, Canada
Long Term Rating	Baa1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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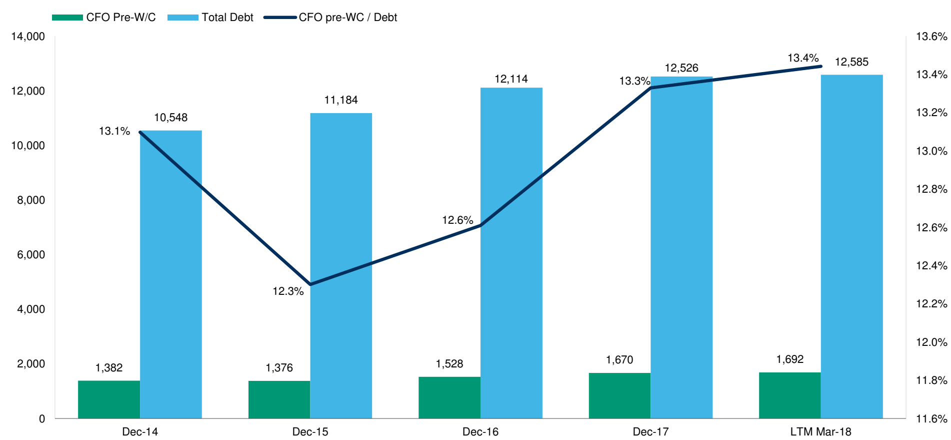
Hydro One Inc.

Update following downgrade and outlook change to stable

Summary

Hydro One Inc.'s (HOI) credit quality reflects its low business risk profile, where roughly 60% of the rate base is transmission and 40% is distribution, driven by a supportive regulatory environment under the Ontario Energy Board (OEB). We expect cash flow from operations to remain predictable but financial metrics to remain weak. Moody's acknowledges that HOI's lower financial metrics are primarily a result of the existing allowed return on equity (currently 9%) and authorized equity layer in the capital structure (currently 40%) that are established by the regulator, and low depreciation rates that are a function of long-life T&D assets.

Exhibit 1
Historical CFO pre-W/C, Debt and CFO pre-W/C to Debt (CAD million)



Source: Moody's Financial Metrics™

Credit strengths

» Supportive regulatory environment

» Predictable cash flow and stable but weak financial metrics

Credit challenges

» High leverage

Rating outlook

The stable rating outlook reflects Moody's expectation that HOI will continue to deliver a consistent underlying financial performance, including a ratio of cash flow to debt in the 11-13% range over the next several years and that the regulatory relationship with the OEB will remain constructive and supportive.

Factors that could lead to an upgrade

An upgrade is possible with improved financial metrics, for example if the ratio of CFO pre-W/C to debt rose to the mid-teens range for a sustained period of time (the ratio was 12.4% at 03/31/2018). We could also upgrade the company with improved regulatory outcomes.

Factors that could lead to a downgrade

We could downgrade the company if CFO pre-W/C to debt is below 11% or if the company experienced a deterioration in its regulatory outcomes.

Key indicators

Exhibit 2

Hydro One Inc.

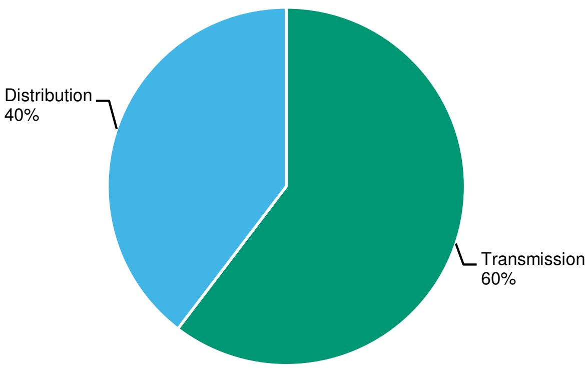
	Dec-14	Dec-15	Dec-16	Dec-17	LTM Mar-18
CFO pre-WC + Interest / Interest	3.9x	3.9x	4.3x	4.4x	4.5x
CFO pre-WC / Debt	13.1%	12.3%	12.6%	13.3%	13.4%
CFO pre-WC – Dividends / Debt	10.5%	4.4%	7.5%	8.9%	9.1%
Debt / Capitalization	54.3%	52.8%	55.0%	55.4%	55.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

HOI is an electricity transmission and distribution company 47.4% indirectly owned by the Province of Ontario; however, its ownership position in HOI will likely decline to about 40% over the next several years. Hydro One Limited (HOL) is the publicly traded vehicle that owns 100% of HOI. HOI is regulated by the Ontario Energy Board (OEB) under cost-of-service and incentive rate frameworks. The transmission business owns and operates virtually all of Ontario's electricity transmission system representing 53% of HOI's total assets of $25.8 billion as at 31 March 2018. The distribution business serves about 1.3 million customers and owns a substantial portion of the province's electricity distribution system representing 36% of HOI's total assets. The remaining assets include the company's telecommunications business and other corporate activities that make a negligible contribution to revenue. HOI began operations in 1999, pursuant to the Electricity Act 1998, when the former Ontario Hydro was restructured into five entities: Ontario Power Generation Inc. (OPG), the Independent Electricity System Operator (IESO), Ontario Electricity Financial Corporation (OEFC), the Electricity Safety Authority and HOI. The Province does not guarantee HOI's debt obligations.

Exhibit 3
HOI's 2017 rate base by segment



Source: HOI's MD&A for the year ended December 31, 2017

Detailed credit considerations

Supportive regulatory environment

The supportive regulatory environment is a key driver of HOI's credit quality. Supporting our view, HOI has a monopoly position as a transmission and distribution (T&D) company with no commodity price risk that underpins its credit strength. We expect the regulatory environment to remain relatively transparent, predictable and broadly credit supportive. The legislative and judicial underpinnings are well developed and we expect them to remain unchanged. Rates for the transmission business are established using cost of service principles with frequent cost of service rate resets, although this business is transitioning to a performance based framework in 2019. Distribution rates are currently established based on an incentive rate mechanism, with periodic cost of service rate resets. The company has a pending performance based rate decision for the distribution business for the period 2018-2022. The company does not have any direct commodity risk exposure since commodity costs are a pass through for the distribution business. However it does have some exposure to volume risk that is typically driven by weather variability and the underlying performance of the economies in its service territories. The company has inherently lower business risk as a T&D business compared to the price, volume, operational or environmental risks typically associated with generation activities. HOI does not have any supply obligations.

Predictable cash flow and stable, albeit weak financial metrics

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of HOI's rate base, its deemed capital structure of 40% equity that is established by the regulator, the allowed return on equity that is currently set at 9% for 2018 and depreciation. We have assumed that the company continues to perform broadly in line with the levels established by the regulator and delivers financial metrics at the low end of an 11-13% range.

Exhibit 4
Summary of key regulatory elements

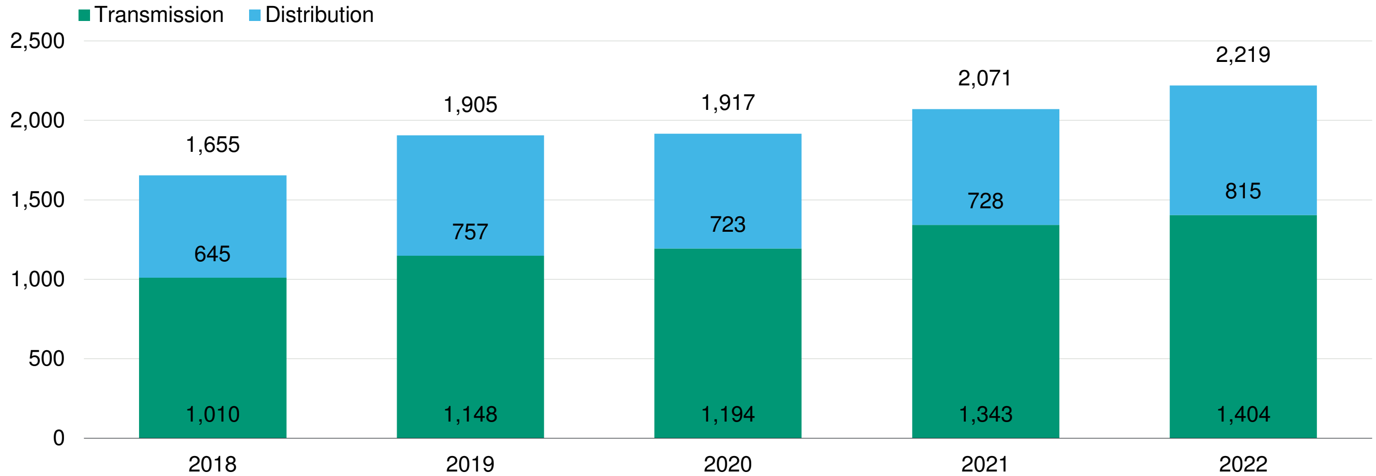
Segment	2017 Rate base, CAD million	Equity Thickness	Allowed ROE	Next Regulatory Decision
Transmission	11,251	40%	9%	TX filing for period 2019-2022 expected in 2018
Distribution	7,389	40%	9%	DX decision for period 2018-2022 expected in 2018

Source: Company filings

HOI continues to move forward with a large capital program of about $5 billion over the period 2018-2020. Historically the company has benefited from a combination of frequent cost of service rate resets in the transmission business. On the distribution side, the capital program has been supported by an approved rate base over its performance based regulation period (2015-2017), mitigating the downward pressure the large capital program would otherwise place on financial metrics. The capital program consists of a series of smaller projects and the company is not exposed to material execution risk that is often associated with larger, more complex projects.

A September 2017 transmission decision included a sharing mechanism for HOI's large deferred tax asset. While HOI is contesting this aspect of the decision, the financial implications are limited as the downside case, including a similar tax sharing mechanism in the distribution business, appears to be an annual reduction in cash flow in the C$50-60 million range, or about 3% of cash flow.

Exhibit 5
Projected capital expenses by segment
(CAD million)



Source: Company

Relationship with the Province of Ontario

We no longer view Hydro One Inc as a government related issuer (GRI) under our methodology and as a result we do not assign any probability of extraordinary support in our credit analysis. We previously viewed HOI as a GRI because HOL was effectively a shell holding company with only a small amount of preferred shares that were held by the government. Since we no longer view HOI as a GRI we no longer assign a Baseline Credit Assessment (BCA), a default dependence or a probability of extraordinary support. We view HOI as comparable to other investor-owned utilities that have no government ownership. Though other investor-owned utilities own equally important assets, we do not incorporate any probability of extraordinary support in their credit analysis. We also do not expect the highly levered planned acquisition of Avista Corp (Baa1 negative) by parent HOL to constrain the ratings of HOI.

Liquidity analysis

HOI maintains adequate liquidity and has demonstrated its ability to readily access capital markets. Up to $1.5 billion can be issued under its commercial paper (CP) program which is backstopped by a bank syndicated committed revolver of $2.3 billion maturing in June 2022. At 31 March 2018, HOI had $989 million in CP borrowings and no revolver borrowings outstanding. HOL has its own $250 million committed credit facility that expires in November of 2021.

HOI relies in part on debt to finance its ongoing capex. The company including parent HOL has a cash and cash equivalents balance of $28 million as of March 31, 2018. The available credit facilities and estimated operating cash flows of around $1.6-1.8 billion in the next 12 months are sufficient to cover capex of around $1.7 billion and dividends of about $600 million. We expect that HOI will refinance $750 million of notes due in October 2018 and $228 million of notes due in March 2019.

Rating methodology and scorecard factors

Exhibit 6

Hydro One Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.2x	Baa	3.7x - 4.2x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	12.4%	Baa	11% - 13%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	6.4%	Ba	6% - 8%	Baa
d) Debt / Capitalization (3 Year Avg)	54.8%	Baa	57% - 61%	Ba
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2018 (LTM);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 7

Peer Comparison Table [1]

	Hydro One Inc. Baa1 Stable			FortisAlberta Inc. Baa1 Stable			FortisBC Inc. Baa1 Stable			Newfoundland Power Inc. Baa1 Stable		
(in CAD millions)	FYE Dec-16	FYE Dec-17	LTM Mar-18	FYE Dec-16	FYE Dec-17	LTM Mar-18	FYE Dec-16	FYE Dec-17	LTM Mar-18	FYE Dec-16	FYE Dec-17	LTM Mar-18
Revenue	6,502	5,947	5,867	572	600	605	361	381	382	572	600	605
CFO Pre-W/C	1,911	1,908	1,963	392	404	408	151	161	160	392	404	408
Total Debt	12,114	12,526	12,585	1,941	2,098	2,183	1,108	1,149	1,153	1,941	2,098	2,183
CFO pre-WC / Debt	12.6%	13.3%	13.4%	15.4%	12.7%	13.3%	9.8%	9.9%	10.3%	18.0%	17.8%	16.5%
CFO pre-WC – Dividends / Debt	7.5%	8.9%	9.1%	8.3%	9.6%	10.3%	5.0%	5.9%	6.2%	14.4%	11.6%	10.5%
Debt / Capitalization	55.0%	55.4%	55.3%	56.1%	56.3%	57.0%	54.8%	55.2%	55.1%	48.8%	48.9%	49.9%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Exhibit 8
Cash Flow and Credit Metrics

CF Metrics	Dec-14	Dec-15	Dec-16	Dec-17	LTM Mar-18
As Adjusted					
FFO	**1,254**	**1,292**	**1,455**	**1,584**	**1,630**
+/- Other	128	84	73	86	62
CFO Pre-WC	1,382	1,376	1,528	1,670	1,692
+/- ΔWC	(119)	139	95	(23)	(118)
CFO	**1,263**	**1,515**	**1,623**	**1,647**	**1,574**
- Div	269	880	620	556	544
- Capex	1,465	1,584	1,610	1,489	1,442
FCF	**(471)**	**(949)**	**(607)**	**(398)**	**(412)**
(CFO Pre-W/C) / Debt	13.1%	12.3%	12.6%	13.3%	13.4%
(CFO Pre-W/C - Dividends) / Debt	10.5%	4.4%	7.5%	8.9%	9.1%
FFO / Debt	11.9%	11.5%	12.0%	12.6%	12.9%
RCF / Debt	9.3%	3.7%	6.9%	8.2%	8.6%

Source: Moody's Financial Metrics™

Ratings

Exhibit 9

Category	Moody's Rating
HYDRO ONE INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa1
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1131064

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades Hydro One Inc to Baa1 from A3; rating outlook stable

20 Jun 2018

Toronto, June 20, 2018 -- Moody's Investors Service ("Moody's") downgraded the ratings for Hydro One Inc. (HOI), including its senior unsecured ratings and its Medium Term Note program to Baa1 from A3. The Prime-2 commercial paper rating has been affirmed. The rating outlook has been changed to stable from negative.

"The acquisition of Avista into the Hydro One corporate family has negative implications for the probability of extraordinary support to Hydro One Inc," said Vice President and Senior Credit Officer Gavin MacFarlane. "The probability of government support is diminishing because it would benefit stakeholders outside of the regulated utility in Ontario."

Downgrades:

..Issuer: Hydro One Inc.

....Senior Unsecured Medium-Term Note Programs, Downgraded to (P)Baa1 from (P)A3

....Senior Unsecured Regular Bonds/Debentures, Downgraded to Baa1 from A3

Outlook Actions:

..Issuer: Hydro One Inc.

....Outlook, Changed To Stable From Negative

Affirmations:

..Issuer: Hydro One Inc.

....Senior Unsecured Commercial Paper, Affirmed P-2

RATINGS RATIONALE

Moody's no longer views Hydro One Inc. as a government related issuer under our methodology. Moody's no longer assigns any probability of extraordinary government support in HOI's credit analysis which has led to the downgrade. Moody's rarely views subsidiaries of holding companies as GRI's but had previously viewed HOI as a GRI because parent Hydro One Limited (HOL unrated) was effectively a shell holding company with only a small amount of preferred shares that were held by the government. By not treating HOI as a GRI, Moody's will no longer assign a Baseline Credit Assessment (BCA), default dependence or probability of extraordinary support. Moody's expects the acquisition of Avista to close in the second half of 2018.

HOI's Baa1 senior unsecured rating reflects its low business risk profile, where roughly 60% of the rate base is transmission and 40% is distribution, driven by a supportive regulatory environment under the Ontario Energy Board (OEB). We expect cash flow from operations to remain predictable and financial metrics to remain weak for the rating. Moody's acknowledges that HOI's lower financial metrics are primarily a result of the existing allowed return on equity (currently 9%) and authorized equity layer in the capital structure (currently 40%) that are established by the regulator.

Outlook:

The stable rating outlook reflects Moody's expectation that HOI will continue to deliver a stable underlying financial performance, including a ratio of cash flow to debt in the 11-13% range over the next several years and that the regulatory relationship with the OEB will remain constructive and supportive.

What could change the rating up:

An upgrade is possible with improved financial metrics, for example if the ratio of CFO pre-W/C to debt rose to the mid-teens range for a sustained period of time (the ratio was 12.4% at 03/31/2018). We could also upgrade the company with improved regulatory outcomes.

What could change the rating down:

We could downgrade the company if CFO pre-W/C to debt is below 11% or if the company experienced a deterioration in its regulatory outcomes.

Hydro One Inc. (HOI) is an electricity transmission and distribution company. HOI is about 47.4% indirectly owned by the Province of Ontario; however, its ownership position in Hydro One Inc. will likely decline to about 40% over the next several years. Hydro One Limited (HOL) is the publicly traded vehicle that owns 100% of HOI. HOI is regulated by the Ontario Energy Board (OEB) under cost-of-service and incentive rate frameworks.

The methodologies used in these ratings was the Regulated Electric and Gas Utilities published in June 2017 and the Government Related Issuers Methodology published in June 2018. Please see the Rating Methodologies page on www.moodys.com for a copy of these methodologies.

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S&P Global Ratings

Research

Research Update:

Hydro One Ltd. And Subsidiary Downgraded To 'A-' On Lower Governance Assessment; Ratings Remain On CreditWatch

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Ratings Score Snapshot(Hydro One Inc.)

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Research Update:

Hydro One Ltd. And Subsidiary Downgraded To 'A-' On Lower Governance Assessment; Ratings Remain On CreditWatch

Overview

- The Government of Ontario recently implemented legislation, requiring Hydro One's board of directors to establish a new executive compensation framework for the board, CEO, and other executives. The legislation also amends the current Ontario Energy Board Act, requiring the Ontario Energy Board to exclude any compensation paid to the CEO and other executives from consumer rates.
- We consider such action as a governance deficiency related to Hydro One's ownership structure and are lowering our management and governance (M&G) assessment on Hydro One Ltd. (HOL) and Hydro One Inc. (HOI) to fair from satisfactory.
- At the same time, we are lowering the issuer credit ratings on both HOL and HOI by one notch to 'A-' from 'A', reflecting the change in our M&G assessment.
- We are also lowering the issue-level rating on HOI's senior unsecured debt to 'A-', the rating on its commercial paper program to 'A-2', and the global short-term and Canadian National Scale ratings to 'A-1 (Low)'.
- All ratings remain on CreditWatch with negative implications.

Rating Action

On Sept. 13, 2018, S&P Global Ratings lowered its issuer credit ratings on Hydro One Ltd. (HOL) and subsidiary Hydro One Inc. (HOI) to 'A-' from 'A'. At the same time, we lowered the short-term issuer credit rating on HOI to 'A-2' from 'A-1'.

We also lowered the issue-level rating on HOI's senior unsecured debt by one notch to 'A-' from 'A' and lowered the rating on HOI's commercial paper program by one notch to 'A-2' from 'A-1' on the global scale and to 'A-1(Low)' from 'A-1(MID) on the Canadian National Scale.

All ratings remain on CreditWatch where we placed them with negative implications on June 15, 2018.

Rationale

The one-notch downgrade reflects our reassessment of HOL's management and governance structure, which has weakened following the government of Ontario's decision to exert its influence on the utility's compensation structure through legislation, potentially promoting the interests and priorities of one owner above those of other stakeholders.

Ontario recently passed the Hydro One Accountability Act that allows the government to issue directives governing HOL's compensation of the board, CEO, and other executives. In addition, Ontario also amended the Ontario Energy Board Act (OEBA) to exclude any amount in respect of compensation paid to HOL's CEO and executives from consumer rates. Although the financial impact of the compensation disallowance is minimal, we think the legislative actions taken reflect a governance deficiency related to HOL's ownership structure because Ontario is exercising its legislative authority to lower electricity rates, consistent with the government's election campaign promises. In our view, the use of this legislative authority to influence HOL's compensation structure for some executives undermines the effectiveness of the company's governance structure, and potentially promotes the interests and priorities of the Ontario government above those of other stakeholders. We also note that these events followed the recent resignation of the entire previous board of Hydro One.

Our view of HOL's business and financial risks is unchanged. The business risk profile continues to reflect the utility's large electricity distribution and transmission operations that serves about 1.3 million electric customers covering approximately 75% of the geographic area of Ontario. The company historically benefited from supportive regulation in Ontario that has enabled utilities to earn close to their authorized return on equity through the use of a forward-looking test year, multiyear rate-setting that adjusts to keep costs and rates aligned, decoupling, and various variance accounts that foster full cost recovery. Furthermore, we expect HOL's consolidated business risk profile will not be affected because of the Avista Corp. acquisition. We believe the jurisdictions in which Avista operates benefit from reasonably supportive regulation. In addition, the purchase gives HOL some geographic diversity and entry into low-risk natural gas distribution operations.

From a financial risk perspective, we expect credit metrics to remain weak for 2018 due to timing of the closing of the Avista transaction. Under our base case scenario, which includes the current financing plan of Avista that comprises about C$1.54 billion of equity and C$3.4 billion (US$2.6 billion) of new debt, capital spending of about C$2 billion, and dividend payments of about C$530 million, we forecast adjusted funds from operations (AFFO) to total debt for HOL, to consistently reflect about 10% for the 2019-2020 period, after the transaction closes. In addition, we do not expect the compensation disallowance to have any significant impact on HOL's cash flow. Our base case scenario also reflects the acquisition of Peterborough Distribution Inc. for about C$105 million, incremental executive compensation costs of about C$20 million, and capital spending of about C$2.5 billion each year.

Liquidity

We assess HOL's liquidity as adequate. We expect liquidity sources to exceed uses more than 1.1x over the next 12 months. In the event of a 10% drop in the company's EBITDA, we also expect liquidity sources will cover uses. In our view, the company has sound relationships with banks and generally satisfactory standing in the credit markets. In the unlikely event of liquidity distress, we expect HOL to scale back its capital spending to preserve credit metrics.

Principal liquidity sources include:

- Cash of about C$1.25 billion as of June 30, 2018.
- Committed credit facilities availability of about C$7.43 billion as of June 30, 2018, including that of Avista and the committed bridge facilities for the Avista transaction.
- Cash FFO of about C$1.9 billion over the next 12 months.

Principal liquidity uses include:

- Debt maturities of about C$981 million over the next 12 months.
- Maintenance capital spending of about C$1.3 billion over the next 12 months.
- Dividend payments of about C$600 million over the next 12 months.
- Acquisitions of about C$5 billion, including Avista and PDI.

CreditWatch

We will resolve the CreditWatch placements of the ratings on HOL and HOI as we get closer to the transaction's closing, including final regulatory approvals from key states, including Washington, Avista's largest regulatory jurisdiction. In addition, the resolution of our CreditWatch placement will depend on our confirmation of the company's forward strategy after the board appoints a new permanent CEO for HOL.

Ratings Score Snapshot(Hydro One Ltd.)

Issuer Credit Rating: A-/Watch Neg/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low

- Competitive position: Excellent

Financial risk: Significant

Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Fair (-1 notch)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a-

Group credit profile: a-

Status within group: Parent

Ratings Score Snapshot(Hydro One Inc.)

Issuer Credit Rating: A-/Watch Neg/A-2

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Fair (-1 notch)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a-

Group credit profile: a-

Status within group: core (no impact)

Issue Ratings--Subordination Risk Analysis

Capital structure

HOL's capital structure consists of about $10.5 billion of senior unsecured long-term debt, all of which are issued by subsidiary HOI. There is currently no debt at the HOL level.

Analytical conclusions

We consider HOI as a qualifying utility in accordance with our criteria. As such we rate the senior unsecured debt at HOI the same as our issuer credit rating on HOI.

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings List

Downgraded

	To	From
Hydro One Limited		
Issuer Credit Rating	A-/Watch Neg/--	A/Watch Neg/--
Hydro One Inc.		
Issuer Credit Rating	A-/Watch Neg/A-2	A/Watch Neg/A-1
Hydro One Inc.		
Senior Unsecured	A-/Watch Neg	A/Watch Neg
Commercial Paper	A-2/Watch Neg	A-1/Watch Neg
Commercial Paper	A-1(LOW)/Watch Neg	A-1(MID)/Watch Neg

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

S&P Global
Ratings

Research

Research Update:

Hydro One Ltd. And Sub Ratings Affirmed As Regulator Rejects M&A Deal With Avista, Off Watch; Outlook Negative

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Research Update:

Hydro One Ltd. And Sub Ratings Affirmed As Regulator Rejects M&A Deal With Avista, Off Watch; Outlook Negative

Rating Action Overview

- The Washington Utilities and Transportation Commission (WUTC) has denied the merger petition between Hydro One Ltd. (HOL) and Avista Corp.
- The WUTC's decision, in our view, significantly increases the likelihood that the transaction will not close as expected, reducing the possibility of an imminent ratings downgrade on HOL.
- However, in our assessment, the WUTC's decision weakens HOL's ability to track, adjust, and control the execution of its strategy, and raises broader concerns regarding HOL's governance and strategic direction as it seeks a permanent CEO.
- On Dec. 10, 2018, S&P Global Ratings affirmed its 'A-' issuer credit ratings on HOL and subsidiary Hydro One Inc. (HOI) and removed the ratings from CreditWatch, where they were placed with negative implications on June 15, 2018. The outlook on both entities is negative.
- We also affirmed our issue-level ratings on HOI, including the 'A-' rating on its senior unsecured debt, and the 'A-2' global and 'A-1 (LOW)' Canadian National Scale ratings on its commercial paper program. We removed the ratings from CreditWatch with negative implications.
- The negative outlooks reflect uncertainty about HOL's ability to convert its strategy into constructive actions that support the company's financial performance. In addition, the negative outlook incorporates broader concerns related to HOL's governance, uncertainty regarding the company's strategic direction, and our revised base-case assumption that the Avista transaction is unlikely to close as expected, the effect of which results in weaker stand-alone financial measures for HOL through 2019.

Rating Action Rationale

The removal of our CreditWatch negative listing reflects the decreased likelihood for a one-notch downgrade, incorporating our revised assumption that the pending transaction with Avista Corp. is unlikely to close as expected. As a result we forecast HOL's funds from operations (FFO) to debt, without Avista, to be about 12% during our 2019-2020 outlook period. However, the WUTC's decision weakens our view of HOL's ability to track, adjust, and control the execution of its strategy, and raises broader concerns related to

HOL's governance and strategic direction. Moreover, our revised base-case assumptions suggest weaker stand-alone financial measures for the company through 2019, collectively warranting a negative outlook for HOL and HOI.

Our assessment of HOL's business risk is unchanged and continues to reflect the utility's large electricity distribution and transmission operations that serve about 1.3 million electricity customers covering approximately 75% of the province of Ontario. The company has historically benefited from supportive regulation in Ontario that enables utilities to earn close to their authorized return on equity. This is done through the use of a forward-looking test year, multiyear rate-setting that adjusts to keep costs and rates aligned, decoupling, and variance accounts that foster full cost recovery. Our base-case assumes the regulatory framework in Ontario remains transparent, stable, and independent from government or political influence.

We assess HOL's financial risk using our low volatility financial benchmark table, reflecting the company's low-risk regulated utility operations, and management of regulatory risk. Under our revised base-case scenario, which assumes merger termination fees, redemption of the first installment of the convertible debentures of about C$500 million and accrued interest, and transaction fees incurred thus far, we expect FFO to debt of about 11.5% in 2019.

Historically, the rationale for the positive ratings analysis modifier reflects our view that the consolidated credit profile of HOL was incrementally stronger than other peers with similar business profiles, which is no longer the case. Currently, our assessment of the positive ratings analysis modifier reflects our expectation of robust financial measures for HOL at its current financial risk profile category. Any material deterioration in HOL's financial performance from our base case scenario could warrant a revision of this modifier, possibly resulting in a one-notch downgrade.

Outlook

The negative outlooks reflect uncertainty about HOL's ability to convert its strategy into constructive actions that support the company's financial performance. In addition, the negative outlook incorporates broader concerns related to HOI's governance, uncertainty regarding the company's strategic direction, and our revised base-case assumption that the Avista transaction is unlikely to close as expected, the effect of which, results in weaker stand-alone financial measures for HOL through 2019.

Downside scenario

We could take a negative rating action on HOL over the next 12 months if the WUTC reverses its decision on the HOL-Avista merger. We could also lower the rating if the company's strategic decisions result in weaker business or financial risk assessments, including FFO to debt that consistently remains below 12%.

Alternatively, we could downgrade HOL if the Ontario government intervenes further in HOL's business or operating decisions, resulting in additional governance deficiencies that we consider severe.

Upside scenario

We could revise the outlook on HOL to stable if the company continues its historic focus on low-risk regulated utility operations and the company's forward strategy does not weaken its business risk and financial measures, maintaining FFO to debt above 12%, consistently.

Company Description

Hydro One, through its subsidiaries, operates as an electrical transmission and distribution (T&D) company in Ontario. It operates through three segments: transmission, distribution, and other business. The company owns and operates approximately 30,000 circuit kilometers of high-voltage transmission network, 123,000 circuit kilometers of low-voltage distribution network, and 308 transmission stations. It serves approximately 1.3 million residential and business customers across the province of Ontario, as well as large industrial customers and local distribution companies.

Our Base-Case Scenario

- Assessment of HOL on a stand-alone basis without Avista.
- Merger termination fees per the terms of the merger agreement.
- Redemption of the first installment of the convertible debentures of about C$500 million, plus accrued interest, issued in 2017.
- No structural change to the utility regulatory framework in Ontario.
- The Ontario utility regulator, the Ontario Energy Board (OEB) remains independent from government interference.
- No adverse regulatory decisions from the OEB.

Liquidity

We assess HOL's liquidity as adequate. We expect liquidity sources to exceed uses by more than 1.1x over the next 12 months. In the event of a 10% decline in EBITDA, we also expect liquidity sources will cover uses. In our view, the company has sound relationships with banks and a generally satisfactory standing in the credit markets. In the unlikely event of liquidity distress, we expect HOL to scale back its capital spending to preserve its liquidity position.

Principal liquidity sources:

- About C$615 million cash as of Sept. 30, 2018;
- Committed credit facilities availability of about C$2.55 billion as of Sept. 30, 2018; and
- Cash FFO of about C$1.6 billion over the next 12 months.

Principal liquidity uses:

- Debt maturities of about C$1.9 billion over the next 12 months, including long-term, short-term, commercial paper, and redemption of the convertible debentures;
- Capital spending of about C$1.6 billion over the next 12 months;
- Dividend payments of about C$600 million over the next 12 months; and
- About C$105 million for the acquisition of Peterborough Distribution Inc.

Environmental, Social, And Governance

HOL's exposure to environmental risk is quite manageable compared with its electric utility peer group, since T&D companies are more favorably positioned than their counterparts with owned power generation assets.

From a social perspective, high power prices and consumer electricity bills are highly politicized in Ontario. We view this negatively in terms of regulatory advantage, since political interference is a potential negative credit factor. However, the primary goal of the company's critics is focused on reducing power costs, not T&D rates. These objectives can reduce social risks in the short term, but excessive political interference could constraint management's effectiveness over time and hinder long-term credit quality.

From a management and governance standpoint, the Ontario government recently passed an amendment to the Ontario Energy Board Act (OEBA) to exclude any compensation paid to HOL's CEO and other senior executives from consumer rates. We view this legislative action as a governance deficiency related to HOL's ownership structure since the Ontario Province exercised its legislative authority to lower electricity rates, consistent with the government's election campaign promises. In our view, the use of this legislative authority to influence HOL's compensation structure for executives undermines the effectiveness of the company's governance structure, and potentially promotes the interests and priorities of the Ontario government above those of other stakeholders. We also note that these events followed the recent resignation of Hydro One's entire previous board of directors. Additional interferences in HOL's business or operating decisions could result in a weaker assessment of the company's governance, reflecting severe deficiencies.

With respect to HOL's strategic positioning, the WUTC's rejection of its merger petition with Avista suggests that HOL may be unable to convert strategic decisions into constructive actions, which in our assessment weakens the company's overall ability to track, adjust and control the execution of its strategy.

Issue Ratings - Subordination Risk Analysis

Capital structure

HOL's capital structure consists of about $10.5 billion of senior unsecured long-term debt, all of which is issued by HOI. There is no senior unsecured debt at the HOL level.

Analytical conclusions

We consider HOI as a qualifying investment-grade regulated utility under our criteria. As such, we rate its senior unsecured debt the same as our issuer credit rating on HOI.

Ratings Score Snapshot(Hydro One Ltd.)

Issuer Credit Rating: A-/Negative/--

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Fair (-1 notch)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a-

Group credit profile: a-

Status within group: Parent

Ratings Score Snapshot(Hydro One Inc.)

Issuer Credit Rating: A-/Negative/A-2

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Fair (-1 notch)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a-

Group credit profile: a-

Status within group: core (no impact)

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings List

Ratings Affirmed; CreditWatch/Outlook Action

	To	From
Hydro One Limited		
Issuer Credit Rating	A-/Negative/--	A-/Watch Neg/--
Hydro One Inc.		
Issuer Credit Rating	A-/Negative/A-2	A-/Watch Neg/A-2
Hydro One Inc.		
Senior Unsecured	A-	A-/Watch Neg
Commercial Paper	A-1(LOW)	A-1(LOW)/Watch Neg
Commercial Paper	A-2	A-2/Watch Neg

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2017)

	Total per Exhibit A-06-02-02	Adjustments	Utility Income
	(a)	(b)	(c)
Revenue			
Transmission Tariff	1,489		1,489
Other	30		30
	1,519		1,519
Costs			
Operation, maintenance, and administration	386	(1)	385
Depreciation and amortization	403		403
	789	(1)	788
Income before financing charges and income taxes	730	1	731
Financing charges	230		230
Income taxes	67		67
Net Income	433	1	434

Adjustment relates to program expenditures that are not included in regulated revenue requirement.

Witness: Samir Chhelavda

PROSPECTUS FOR MOST RECENT FINANCING

This Exhibit includes copies of the prospectus for recent public debt offerings.

- Attachment 1: Short Form Base Shelf Prospectus, March 8, 2018

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities. All shelf information omitted from this shelf prospectus will be contained in one or more prospectus supplements that will be delivered to purchasers together with the base shelf prospectus.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities to be issued hereunder have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws and may not be offered, sold or delivered within the United States of America and its territories and possessions except in certain transactions exempt from the registration requirements of such Act. See "Plan of Distribution".

***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada**. Each shelf prospectus supplement will be incorporated by reference into this shelf prospectus for the purposes of securities legislation as of the date of the shelf prospectus supplement and only for the purposes of the distribution of the securities to which the shelf prospectus supplement pertains. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of Hydro One Inc., 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5, (416) 345-6044 and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

New Issue — March 8, 2018

hydro One

HYDRO ONE INC.
$4,000,000,000
Medium Term Notes
(unsecured)

Hydro One Inc. (the "company") may offer and issue from time to time medium term notes (the "Notes") in an aggregate principal amount of up to $4.0 billion in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) during the twenty-five months from the date of issuance of the receipt for this short form prospectus.

The Notes will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes.

Notes issued hereunder will be direct unsecured obligations of the company, will be issued under a trust indenture in any number of series or separate issues thereof, and will at their respective dates of issue rank *pari passu* with all other unsecured and unsubordinated Indebtedness (as defined below) of the company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company.

The specific variable terms of an offering of Notes (including the aggregate principal amount of the Notes being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the company to extend the maturity date of the Notes, the name(s) of the dealer(s) offering the Notes, the commission payable to such dealer(s), the method of distribution and the net proceeds to the company) will be set forth in a prospectus supplement or pricing supplement which will accompany this short form prospectus. Unless otherwise indicated in a prospectus supplement or pricing supplement, the Notes will not be listed on any securities exchange.

This short form prospectus does not qualify the issuance of Notes: (i) entitling the holder to exchange or convert the Notes into securities issued by the company or into securities issued by another entity; or (ii) in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to one or more underlying interests including, for example, an equity or debt security, a statistical measure of economic or financial performance including, but not limited to, any currency, consumer price or mortgage index, or the price or value of one or more commodities, indices or other items, or any other item or formula, or any combination or basket of the foregoing items. For greater certainty, however, this short form prospectus does qualify for issuance Notes in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to published rates of a central banking authority or one or more financial institutions, such as a prime rate or a bankers' acceptance rate, or to recognized market benchmark interest rates, such as CDOR or EURIBOR, or to interest rates on Government of Canada bonds.

Investing in the Notes involves risks. See "Risk Factors" in this short form prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement.

Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See "Risk Factors".

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or that resides outside of Canada, even if the party has appointed an agent for service of process. See "Agent for Service of Process in Canada".

RATES ON APPLICATION

The Notes may be offered severally by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to the dealer agreement referred to under the heading "Plan of Distribution" or such other dealers as may be selected from time to time by the company (the "Dealers"), in each case acting as agent of the company or as principal. Where the Notes are offered by the Dealer(s) as agent, the commissions payable in connection with sales of such Notes shall be agreed from time to time between the company and any such Dealers. Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between the company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. In each case, the commissions payable, if any, will be set forth in a prospectus supplement or pricing supplement that will accompany and be incorporated by reference in this short form prospectus. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to the company. In connection with any offering of Notes, the Dealers may, when acting as an agent or purchasing as principal, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution". The company may also offer the Notes directly to potential purchasers at prices and upon terms negotiated between the purchaser and the company.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "HOI Lenders") that have made a $2.3 billion unsecured revolving credit facility (the "HOI Credit Facility") available to the company. In addition, BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD

Securities Inc. are subsidiaries or affiliates of lenders (the "HOL Lenders", and together with the HOI Lenders, the "Lenders") that have made a $250 million operating credit facility (the "HOL Credit Facility") available to the company's sole shareholder, Hydro One Limited ("HOL"). As of March 8, 2018, there is no outstanding indebtedness under the HOI Credit Facility or the HOL Credit Facility. However, if and when there is outstanding indebtedness to any of the HOI Lenders under the HOI Credit Facility, to any of the HOL Lenders under the HOL Credit Facility, or under any future credit facility with one or more of the Lenders, the company may be considered a connected issuer of those Dealers who are subsidiaries or affiliates of such Lenders for purposes of securities laws in Canada. See "Plan of Distribution".

The offering of Notes is subject to the approval of certain legal matters on behalf of the company by Osler, Hoskin & Harcourt LLP and on behalf of the Dealers by Blake, Cassels & Graydon LLP.

The company's head and registered office is located at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

The company's consolidated financial statements incorporated by reference in this short form prospectus have been prepared in accordance with U.S. generally accepted accounting principles. Unless otherwise specified or the context otherwise requires, all references herein to currency are references to Canadian dollars.

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DOCUMENTS INCORPORATED BY REFERENCE

The following documents, which have been filed with the securities commission or similar regulatory authority in each of the provinces of Canada, are specifically incorporated by reference in this short form prospectus:

(a) the annual information form of the company dated March 27, 2017 (the "AIF");

(b) the comparative audited consolidated financial statements of the company, and the notes thereto, as at and for the fiscal years ended December 31, 2017 and 2016, together with the report of the auditors thereon dated February 12, 2018 (the "Annual Financials"); and

(c) management's discussion and analysis of financial results for the year ended December 31, 2017.

Updated earnings coverage ratios, as required, will be filed quarterly with the appropriate securities regulatory authorities either as prospectus supplements or as part of the company's unaudited interim and audited annual consolidated financial statements and will be deemed to be incorporated by reference into this short form prospectus for the purposes of the offering of Notes hereunder.

Any documents of the type required by National Instrument 44-101 – *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, including documents of the types referred to in paragraphs (a) through (c) above and any interim financial statements and related management's discussion and analysis, material change reports (except confidential material change reports) and business acquisition reports filed by the company with the securities regulatory authorities in Canada since the end of the financial year in respect of which its then current annual information form is filed, shall be deemed to be incorporated by reference into this short form prospectus. Upon a new annual information form and new annual financial statements and related management's discussion and analysis being filed by the company with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this short form prospectus, the previous annual information form, previous annual financial statements and related management's discussion and analysis, and all previous interim financial statements and related management's discussion and analysis filed prior to the commencement of the company's financial year in which the new annual information form, new annual financial statements and related management's discussion and analysis are filed shall be deemed no longer to be incorporated into this short form prospectus for purposes of future offers and sales of Notes hereunder.

A pricing supplement or prospectus supplement containing the specific variable terms for an issue of Notes will be delivered to purchasers of such Notes together with this short form prospectus and will be deemed to be incorporated by reference into this short form prospectus as of the date of the pricing supplement or prospectus supplement, solely for the purposes of the Notes issued under that pricing supplement or prospectus supplement. Any template version of marketing materials for an issue of Notes filed by the company with the securities regulatory authorities in Canada after the date of the pricing supplement or prospectus supplement in respect of such issue of Notes and before the termination of the distribution of such Notes will be deemed to be incorporated by reference into that pricing supplement or prospectus supplement.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded and not incorporated by reference, for purposes of this short form prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this short form prospectus, except as so modified or superseded.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This short form prospectus, including the documents incorporated by reference herein, contains "forward-looking information" within the meaning of applicable Canadian securities laws that is based on current expectations, estimates, forecasts and projections about the business of the company and the industry, regulatory and economic environments in which the company operates, and includes beliefs and assumptions made by the management of the company. Such information includes, but is not limited to, statements about: the general development of the company's business; the company's strategy and goals; future capital expenditures; the company's transmission and distribution rate applications, including resulting decisions, rates and expected impact and timing; the company's liquidity and capital resources and operational requirements; the company's standby credit facilities; expectations regarding the company's financing activities; the company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the company's credit ratings; and expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario. Additional forward-looking information is identified in the various documents incorporated by reference in this short form prospectus, including the section entitled "Forward-Looking Information" in the company's annual information form and the section entitled "Forward-Looking Statements and Information" in the company's management's discussion and analysis. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target" and variations of such words and similar expressions are intended to identify such forward-looking information. The forward-looking information contained in this short form prospectus, including the documents incorporated by reference herein, are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. In particular, this forward-looking information is based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining required approvals; no unforeseen changes in rate orders or rate setting methodologies for the company's distribution and transmission businesses; the continued use and availability of U.S. GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the company including information obtained by the company from third-party sources. Actual outcomes and results may differ materially from what is expressed, implied or forecasted in this forward-looking information. While the company does not know what impact any of these differences may have, the company's business, results of operations, financial condition and credit stability may be materially adversely affected if such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are discussed in more detail under "Risk Factors" in this short form prospectus and in any prospectus supplement or pricing supplement and in the sections entitled "Forward-Looking Information" and "Risk Factors" in the company's annual information form and the sections entitled "Risk Management and Risk Factors" and "Forward-Looking Statements and Information" in the company's management's discussion and analysis. You should carefully consider these and other factors and not place undue reliance on forward-looking information.

The company does not intend, and the company disclaims any obligation, to update any forward-looking information, except as required by law.

THE COMPANY

The company is the largest electricity transmission and distribution company in Ontario. The company owns and operates substantially all of Ontario's electricity transmission network, and the company is the largest electricity distributor in Ontario by number of customers. The company owns and operates approximately 30,000 circuit kilometres of high-voltage transmission lines and approximately 123,000 circuit kilometres of primary low-voltage distribution lines.

The company has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

The company's transmission business consists of owning, operating and maintaining its transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board. This includes the company's 66% interest in B2M Limited Partnership, a limited partnership between the company and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. The company's transmission business accounted for approximately 53% of its total assets as at December 31, 2017, and approximately 51% of its total revenue, net of purchased power, in 2017. All of the company's transmission business is carried out through its wholly-owned subsidiary, Hydro One Networks Inc. and through other wholly-owned subsidiaries of the company that own and control Hydro One Sault Ste. Marie LP, as well as the portion of the company's transmission business held through B2M Limited Partnership, which the company controls.

The company's distribution business consists of owning, operating and maintaining its distribution system, which the company owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. The company's distribution system is also the largest in Ontario, and principally serves rural communities. The company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the Ontario Energy Board. The company's distribution business accounted for approximately 36% of its total assets as at December 31, 2017 and approximately 49% of its total revenues, net of purchased power, in 2017.

The company's other business segment consists of certain corporate activities, including a deferred tax asset, and is not rate regulated. The deferred tax asset arose on the transition from the provincial payments in lieu of tax regime to the federal tax regime in connection with the initial public offering of HOL and reflects the revaluation of the tax basis of the company's assets to fair market value. The other business segment accounted for approximately 11% of the company's total assets as at December 31, 2017 and nil of its total revenues, net of purchased power, in 2017.

The company is a wholly-owned subsidiary of HOL. The address of the head and registered office and principal place of business of the company is 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

See the section entitled "Business of Hydro One" in the AIF for further details relating to the company's business.

CREDIT RATINGS

As of the date of this short form prospectus, the Notes have been rated A with a negative outlook by Standard & Poor's Ratings Services ("S&P") and A (high) with a stable trend by DBRS Limited ("DBRS") and have been provisionally rated A3 with a negative outlook by Moody's Investors Services, Inc. ("Moody's"). The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity and willingness of a company to meet its financial commitment on an obligation in accordance with the terms of the obligation.

The rating agencies rate long-term debt instruments by rating categories ranging from a high of AAA to a low of D (C in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P are in the third highest category and mean the obligor's capacity to meet its financial commitments and obligations is strong but is considered somewhat more susceptible to the adverse effects of changes in circumstances and adverse economic conditions than obligations in higher rated categories. S&P may modify the ratings from AA to CCC using a plus (+) or minus (-) sign to show relative standing within the major rating categories. The addition of a rating outlook such as "stable", "positive", "negative" or "developing" assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). An outlook is not necessarily a precursor of a ratings change. Long-term debt instruments which are rated in the A category by DBRS are in the third highest category and are considered to be of a good credit quality, with substantial capacity for the payment of financial obligations. Entities in the A category are considered to be vulnerable to future events, but qualifying negative factors are considered manageable. The "high" modifier indicates relative standing within this rating category by DBRS. The assignment of a "positive", "stable" or "negative" trend provides guidance in respect of DBRS' opinion regarding the trend for the rating. The rating trend indicates the direction in which DBRS considers the rating may move if present circumstances continue, or in certain cases, unless challenges are addressed by the issuer. Long-term debt instruments which are rated in the A category by Moody's are in the third highest category and are considered upper-medium grade and are subject to low credit risk. Moody's applies numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 3 indicates a ranking in the lower end of that generic rating category. The A3 rating assigned to the Notes by Moody's is a provisional rating and a definitive rating will be assigned to each offering of Notes under this short form prospectus only after Moody's reviews the terms and conditions of the drawdown. In some circumstances, no rating may be assigned to a drawdown, and if a definitive rating is issued, it may differ from the provisional rating. The addition of a rating outlook such as "stable", "positive", "negative" or "developing" indicates Moody's opinion regarding the likely rating direction over the medium term.

The ratings mentioned above are not a recommendation to purchase, sell or hold the company's debt securities including the Notes and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

The company has made, and anticipates making, payments to each of S&P, DBRS and Moody's pursuant to the ratings agency services agreements entered into with such credit rating organizations with respect to the ratings assigned to the long-term debt and commercial paper of the company. In addition, as Notes are issued, the company expects to make payments to such credit rating organizations pursuant to the ratings agency services agreements entered into with such credit rating organizations for the ratings they assign to the Notes of a particular series. HOL has made payments to S&P for ratings evaluation services in connection with its proposed acquisition of Avista Corporation, including rating evaluation services related to the company. There have been no other services provided by any of such credit rating organizations to the company within the last two years.

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to the company, and Blake, Cassels & Graydon LLP, counsel to the Dealers, unless otherwise specified in the applicable prospectus supplement or pricing supplement, the Notes, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) and the regulations thereunder (collectively, the "Tax Act") for a trust governed by a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP"), registered disability savings plan ("RDSP"), deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan for which any employer is the company or an employer who does not deal with the company at arm's length, within the meaning of the Tax Act) or a tax-free savings account ("TFSA").

The Notes will not be a "prohibited investment" for a TFSA, RRSP, RRIF, RDSP or RESP, provided that the holder of the TFSA or RDSP, the annuitant under a RRSP or RRIF or the subscriber of the RESP, (i) deals at arm's length with the company for purposes of the Tax Act, and (ii) does not have a "significant interest", within the meaning of the Tax Act, in the company. Holders of a TFSA or RDSP, annuitants under a RRSP or RRIF and subscribers of an RESP should consult their own tax advisors as to whether the Notes will be a "prohibited investment" for such TFSA, RRSP, RRIF, RDSP or RESP in their particular circumstances.

CONSOLIDATED CAPITALIZATION

There have been no material changes in the company's share and loan capital, on a consolidated basis, since the date of the Annual Financials which have not been disclosed in this shelf prospectus or the documents incorporated by reference herein.

EARNINGS COVERAGE RATIOS

For the twelve months ended December 31, 2017, the company's consolidated income before provision for corporate income taxes and interest expense (net of capitalized interest) was $1,248 million. Interest expense (net of capitalized interest) for this period was $411 million, and including capitalized interest, was $467 million.

The following table sets forth the earnings coverage ratio for the company for the twelve month period ended December 31, 2017, based on audited information, without giving effect to any Notes to be issued under this short form prospectus:

	December 31, 2017
Earnings coverage on long-term debt obligations(1)(2)	2.66

(1) The earnings coverage ratio has been calculated as the sum of net income attributable to the shareholder of the company, provision for corporate income taxes and financing charges divided by the sum of financing charges and capitalized interest.

(2) The earnings coverage ratio has not been adjusted for issuances or repayments of the company's commercial paper subsequent to December 31, 2017 as they would not materially affect the earnings coverage ratio.

DESCRIPTION OF THE NOTES

General

The following is a summary of the material attributes and characteristics of the Notes, and does not purport to be complete and is qualified in its entirety by reference to the Notes and the Trust Indenture (as defined below).

The terms and conditions set forth in this section "Description of the Notes" will apply to each Note unless otherwise specified in the applicable prospectus supplement or pricing supplement. The company reserves the right to set forth in a prospectus supplement or pricing supplement specific variable terms of or amendments to the Notes which are not within the options and parameters set forth in this short form prospectus. References in this section "Description of the Notes" refer to all medium term notes of the company which have previously been or are to be issued under the Trust Indenture.

This short form prospectus qualifies under applicable Canadian securities laws the distribution of $4.0 billion aggregate principal amount of Notes in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) which have been authorized for issue under the Trust Indenture. This amount is subject to amendment from time to time as determined by the company. The company has previously issued $2.3 billion aggregate principal amount of medium term notes under its short form prospectus dated December 14, 2015.

Notes issued hereunder will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units at the time of issue) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes (as described under the heading "Global Notes" below). Each interest-bearing Note will bear interest at either a fixed rate (a "Fixed Rate Note") or a floating rate (a "Floating Rate Note"). Notes will be issued from time to time at such rates of interest and at par, at a premium or at a discount, may be subject to redemption or repayment prior to maturity, or may include terms entitling the company to extend the maturity dates of the Notes, which terms shall be determined by the company based on a number of factors, including advice from the Dealers. The Notes will be unsecured and will, at their respective dates of issue, rank *pari passu* with all other unsecured and unsubordinated Indebtedness and obligations of the company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company. The company may also, from time to time, issue debt securities and incur additional debt otherwise than through the issuance of Notes pursuant to this short form prospectus.

Neither the aggregate principal amount of Notes which will be issued and sold nor the issue price to the public of the Notes has been established as the Notes will be issued at such times, in such amounts and at such prices as the company determines from time to time. Notes issued hereunder will be offered and sold during the twenty-five months from the date of issuance of the receipt for this short form prospectus at prices negotiated with the purchasers, and the prices at which the Notes will be offered and sold may vary as between purchasers and during the distribution period. The Notes will be issued from time to time at the discretion of the company in an aggregate principal amount not to exceed $4.0 billion in Canadian currency, or the equivalent thereof calculated at the applicable rates of exchange prevailing at the time of issue of Notes issued in currencies other than Canadian currency.

The specific variable terms of any offering of Notes, including, in the case of Floating Rate Notes, the information necessary for the calculation of interest thereon, will be set forth in a prospectus supplement or pricing supplement to this short form prospectus. Where Notes are offered and sold in currencies other than Canadian dollars, the Canadian dollar equivalent of the offering price and the rate of exchange at the last feasible date will be included in the applicable prospectus supplement or pricing supplement.

Trust Indenture

The Notes will be issued under a trust indenture dated as of June 4, 2001, as supplemented or modified from time to time (collectively, the "Trust Indenture") between the company and Computershare Trust Company of Canada, as trustee (the "Trustee", which term shall include, unless the context otherwise requires, its successors and assigns). The following is a brief summary of the material attributes and characteristics of the Trust Indenture. This summary does not purport to be complete and reference should be made to the Trust Indenture for more detailed information.

The Trust Indenture permits the issuance from time to time of additional unsecured medium term notes without limitation as to aggregate principal amount, subject to compliance with the covenants contained therein.

The Notes will be direct obligations of the company and will rank pari passu with all other medium term notes from time to time issued and outstanding under the Trust Indenture and with other present and future unsubordinated and unsecured Indebtedness of the company, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company. The Notes will not be secured by any mortgage, pledge or charge, except in the circumstances referred to under the subheading "Negative Pledge".

<u>Negative Pledge</u>

The Trust Indenture contains provisions to the effect that the company will not, nor will it permit any Designated Subsidiary (as defined below) to, create, assume or suffer to exist any Security Interest (as defined below) on any of the company's or the Designated Subsidiary's assets to secure any Obligation (as defined below) unless at the same time it shall secure all the Notes then outstanding on an equal basis. This covenant is, however, subject to the following exceptions:

- any Security Interest that secures the Obligations of a Designated Subsidiary which exists prior to the date on which it becomes a Designated Subsidiary and which (a) was not incurred in contemplation of that person becoming a Designated Subsidiary and (b) was not applicable to the company or any other Designated Subsidiary or the properties or assets of the company or any other Designated Subsidiary;

- any Security Interest granted by the company or a Designated Subsidiary to secure the Notes;

- any Purchase Money Mortgage (as defined below) or Capital Lease Obligation (as defined below) of the company or any Designated Subsidiary;

- any Security Interest on a property or asset acquired by the company or a Designated Subsidiary that secures the Obligations of a person, whether or not that Obligation is assumed by the acquiring person, which Security Interest exists at the time that property or asset is acquired and which (a) was not incurred in contemplation of that property or asset being acquired and (b) was not applicable to the company or any other Designated Subsidiary or the properties or assets of the company or any other Designated Subsidiary;

- any Security Interest given in the ordinary course of business by the company or a Designated Subsidiary to any bank or banks or other lenders to secure any Indebtedness payable on demand or maturing within 18 months of the date that Indebtedness is incurred or of the date of any renewal or extension of that Indebtedness;

- any Security Interest granted by any Designated Subsidiary in favour of the company or any Wholly-Owned Designated Subsidiary (as defined below);

- any Security Interest on or against cash or marketable debt securities pledged to secure any non-speculative Financial Instrument Obligation (as defined below) which hedges Indebtedness of the company or of a Designated Subsidiary;

- any Security Interest for taxes, assessments, government charges or claims that are being contested in good faith and in respect of which appropriate provision is made in the company's consolidated financial statements in accordance with GAAP;

- Security Interests securing appeal bonds or other similar Security Interests arising in connection with contracts, bids, tenders or court proceedings, including, without limitation, surety bonds, security for costs of litigation where required by law and letters of credit, or any other instruments serving a similar purpose;

- a Security Interest in cash or marketable debt securities in a sinking fund account established by the company in support of a series of Notes;

- a lien or deposit under workers' compensation, social security or similar legislation or good faith deposits in connection with bids, tenders, leases, contracts or expropriation proceedings, or deposits to secure public or statutory obligations or deposits of cash or obligations to secure surety and appeal bonds;

- any lien or privilege imposed by law, such as builders', carriers', warehousemen's, landlords', mechanics' and material men's liens and privileges, and any lien or privilege arising out of judgments or awards with respect to which the company or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review; or any liens for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the company or a Designated Subsidiary in good faith; or undetermined or inchoate lien privileges and charges incidental to current operations which have not at such time been filed pursuant to law against the company or a Designated Subsidiary or which relate to obligations not due or delinquent; or the deposit of cash or securities in connection with any lien or privilege referred to in this clause;

- any minor encumbrance, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions as to the company's use of real property, which do not in the aggregate materially detract from the value of that property or materially impair its use in the operation of the business of the company or a Designated Subsidiary;

- any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grant or permit acquired by the company or any Designated Subsidiary, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit or to purchase assets used in connection therewith or to require annual or other periodic payments as a condition to the continuance thereof;

- any lien or right of distress reserved in or exercisable under any lease for rent and for compliance with the terms of that lease;

- any Security Interest granted by the company or a Designated Subsidiary to a public utility or any municipality or governmental or other public authority when required by that utility, municipality or other authority in connection with the operations of the company or a Designated Subsidiary;

- any reservation, limitation, proviso or condition, if any, expressed in any original grants to the company or a Designated Subsidiary from the Crown; and

- any extension, renewal, alteration, substitution or replacement, in whole or in part, of any Security Interest referred to in the foregoing clauses, provided that the extension, renewal, alteration, substitution or replacement of such Security Interest is limited to all or part of the same property that secured the Security Interest, the principal amount of the secured Obligations is not increased by that action, the term of the secured Indebtedness is not shortened and the terms and conditions are no more restrictive in any material respect than the Security Interest so extended.

In addition to the Security Interests permitted above, the company or any Designated Subsidiary may create, assume or suffer to exist any Security Interest on any of its assets if, after giving effect to that Security Interest, the aggregate amount of Indebtedness secured by the Security Interests permitted only by this paragraph does not at that time exceed 5% of the Consolidated Net Worth (as defined below) of the company.

Limitation on Funded Obligations

So long as any of the Notes issued under the Trust Indenture remain outstanding, neither the company nor any of its Designated Subsidiaries will, directly or indirectly, guarantee, incur, issue or become liable for or in respect of any Funded Obligations (as defined below) unless after giving pro forma effect to that guarantee, incurrence, issuance or liability, including the application or use of the resulting net proceeds, the aggregate principal amount of Consolidated Funded Obligations (as defined below) does not exceed 75% of the Total Consolidated Capitalization (as defined below). This covenant, however, will not prevent the incurrence of Capital Lease Obligations, Purchase Money Obligations and non-speculative Financial Instrument Obligations.

Ceasing to be a Designated Subsidiary

The Board of Directors of the company may elect that any Designated Subsidiary cease to be a Designated Subsidiary, except that an election may not be made in respect of any Designated Subsidiary:

- if the Designated Subsidiary owns any Funded Obligations of the company or any shares, voting interests or Funded Obligations of any other Designated Subsidiary;

- if the Designated Subsidiary owns or has any ownership interest in any Principal Property (as defined below); or

- if, after giving effect to the election, the company would not be entitled to issue Funded Obligations in the principal amount of at least $1.00.

Mergers, Consolidations and Sales of Assets

The company will not enter into any transaction in which all or substantially all of its undertaking, property and assets would become the property of any other person (except any of its subsidiaries), whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless:

- the company shall be the surviving person, or the person, if other than the company, formed by the amalgamation, consolidation or into which the company is merged or that acquires by disposition all or substantially all of the property or assets of the company, shall be a company organized and validly existing under the federal laws of Canada or any of its provinces or territories and shall expressly assume, by a supplemental indenture executed and delivered to the Trustee in form satisfactory to the Trustee, all of the company's obligations under the Trust Indenture;

- immediately before and after giving effect to the transaction, no Event of Default (as defined below) or event that with the passing of time or the giving of notice, or both, would constitute an Event of Default shall have occurred and be continuing; and

- neither the company nor any successor, either at the time of or immediately after the consummation of any such transaction, will be insolvent or generally fail to meet, or admit in writing its inability or unwillingness to meet, its obligations as they generally become due.

Events of Default

Each of the following is an Event of Default under the Trust Indenture with respect to Notes of any series:

(1) failure to pay any principal or premium, if any, on any Notes when due, at maturity, upon redemption or otherwise and the continuance of such default for a period of five days;

(2) failure to pay any interest on any Notes when due and the continuance of that default for a period of 45 days;

(3) the sale, transfer or other disposition of all or substantially all of the company's undertaking or assets other than in accordance with the covenant described above under the subheading "Mergers, Consolidations and Sales of Assets";

(4) default in the performance or breach of any other covenant or agreement of the company under the Trust Indenture, any supplemental indenture or the Notes and the continuance of that default for a period of 60 days after written notice to the company by the Trustee or by holders of at least 25% of all Notes issued under the Trust Indenture;

(5) default by the company or any Material Subsidiary (as defined below), whether as primary obligor, guarantor or surety, on any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which Indebtedness exceeds $100 million in the aggregate, beyond any applicable grace period or failure to perform or observe any other agreement, term or condition contained in any agreement under which that Indebtedness is created, or if any default, failure or other event under that agreement shall occur and be continuing, and the effect of that default, failure or other event is to cause $100 million or more of that Indebtedness to become due or to be required to be repurchased prior to any stated maturity;

(6) the rendering of a judgment or judgments, not subject to appeal, against the company or any Material Subsidiary in an aggregate amount in excess of $100 million by a court or courts of competent jurisdiction, which judgment or judgments remain undischarged and unstayed for a period of 60 days; and

(7) specified events of bankruptcy, insolvency or reorganization affecting the company or any Material Subsidiary.

If an Event of Default applicable only to the issued and outstanding Notes of a series occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of Notes of that series then outstanding may declare the principal of, and interest and premium, if any, on all Notes of that series to be due and payable immediately.

If, however, an Event of Default applicable to all Notes issued and outstanding under the Trust Indenture, or an Event of Default described in clause (5), (6), or (7) above occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of all issued and outstanding Notes, treated as one class, may declare the principal amount of all the Notes then outstanding to be due and payable immediately.

Subject to the provisions of the Trust Indenture relating to the duties of the Trustee, in case an Event of Default applicable to any Notes shall occur and be continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Trust Indenture at the request or direction of any of the holders of those Notes, unless those holders shall have offered to the Trustee reasonable indemnity. Subject to such provisions for the indemnification of the Trustee, the holders of not less than 25% in principal amount of Notes of a series or all series affected by an Event of Default will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee in respect of the Notes of a series or all series affected by that Event of Default.

Defeasance

The Trust Indenture requires the Trustee to release the company from its obligations under the Trust Indenture relating to a particular series of Notes if specified conditions are satisfied. Among other things, the company must deposit money or securities for the payment of all principal of and interest and any other amounts due or to become due on that series of Notes as well as for the payment of the expenses of the Trustee. The deposited money or securities must be denominated in the currency in which principal of these Notes is payable and, in the case of deposited securities, must constitute direct obligations of Canada or a province of Canada or an agency or instrumentality of Canada.

Amendments and Waivers

The Trust Indenture provides that the company and the Trustee may enter into supplemental indentures ("Supplemental Indentures") without the consent of the holders of the Notes of any or all series to:

- add limitations or restrictions to be observed upon the amount or issue of Notes, provided that such limitations or restrictions shall not be materially adverse to the interests of the holders of the Notes;
- add covenants for the protection of the holders of Notes;
- provide for any additional Event of Default;
- make such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising thereunder, including the making of any modifications in the form of the Notes which do not affect the substance thereof and which it may be expedient to make, provided that such provisions and modifications will not adversely affect the holders of Notes;
- provide for the issue of Notes of any one or more series and establish the form and terms of any series of Notes;
- evidence the succession, or successive successions, of successors to the company and the covenants and obligations assumed by any such successor, in accordance with the provisions of the Trust Indenture; and
- giving effect to any extraordinary resolution or ordinary resolution of the holders of Notes in accordance with the Trust Indenture.

Other amendments and modifications of the Trust Indenture, Supplemental Indentures and Notes may be made by the company and the Trustee with the consent of the holders of not less than 66⅔% (and in certain circumstances, a majority) in principal amount of Notes of all series voting on such amendment or modification and, if the rights of holders of Notes of a particular series of Notes would be affected differently than rights of holders of Notes of other series, not less than 66⅔% (and, in certain circumstances, a majority) in principal amount of Notes of the series so affected by that modification or amendment voting on such amendment or modification, in each case, voting as one class. However, no modification or amendment may, without the consent of the holder of each outstanding Note of the affected series,

- reduce the principal amount at maturity of, extend the fixed maturity of, or alter the redemption provisions of, those Notes;
- change the currency in which those Notes or any premium or accrued interest is payable;
- reduce the percentage in principal amount at maturity outstanding of those Notes that must consent to an amendment, supplement or waiver or consent to take any action under the Trust Indenture, Supplemental Indenture or those Notes;
- impair the right to institute suit for the enforcement of any payment on or with respect to those Notes;
- waive a default in payment with respect to those Notes;
- reduce the rate or extend the time for payment of interest on those Notes;
- affect the ranking of those Notes in a manner adverse to the holders; or
- make any changes to the Trust Indenture, Supplemental Indentures or those Notes that would result in the company being required to make any withholding or deduction from payments made under or with respect to those Notes.

The holders of 66⅔% in principal amount of the Notes of all series with respect to which an Event of Default shall have occurred and be continuing, voting as one class, may waive any Event of Default, except in the case of a default in payment of principal with respect to the Notes or except, further, in respect of a covenant or provision which cannot be modified or amended without the consent of the holder of each outstanding Note affected.

Definitions

In addition to the definitions set out above, the Trust Indenture contains definitions substantially to the following effect:

"Capital Lease Obligation" means any monetary obligation of the company or a Designated Subsidiary under any leasing or similar arrangement which, in accordance with GAAP, would be classified as a capital lease and for the purposes of the Trust Indenture, the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with GAAP;

"Consolidated Funded Obligations" means the aggregate amount of all Funded Obligations of the company and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP;

"Consolidated Net Worth" means, as at any date, the consolidated shareholders' equity of the company and its Designated Subsidiaries as at that date determined in accordance with GAAP;

"Contingent Liability" means any agreement, undertaking or arrangement by which any person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Obligation of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any person's obligation under any Contingent Liability will, subject to any limitation contained in that Contingent Liability, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

"Designated Subsidiary" means any subsidiary which is designated as such by the directors of the company, provided that any such subsidiary may only be so designated if, after giving effect thereto, the company would be entitled under the Trust Indenture to issue Funded Obligations in the principal amount of at least $1.00 and further provided that a subsidiary cannot be so designated if any of its shares are owned by a subsidiary which is not itself a Designated Subsidiary;

"Financial Instrument Obligations" means, with respect to any person at any time, the obligations of that person under any transaction that is a rate swap, basis swap, forward rate transaction, commodity swap, commodity option, commodity future, equity or equity index swap or option, bond, note or bill option, interest rate option, forward foreign exchange transaction, cap, collar or floor transaction, currency swap, cross-currency rate swap, swaption, currency option or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing to the extent of the net amount due to or accruing due by the person under that obligation, determined by marking that obligation to market at that time in accordance with its terms;

"Funded Obligations" means all Indebtedness created, assumed or guaranteed, which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation, assumption or guarantee thereof;

"GAAP" means as at any date of determination:

(1) accounting principles which are recognized as being generally accepted in Canada, if the company is then preparing its financial statements in accordance with such principles; or

(2) accounting principles which are recognized as being generally accepted in the United States, if the company is then preparing its financial statements in accordance with such principles;

"Indebtedness" means, without duplication, with respect to any person,

(1) all obligations of that person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations, excluding Preferred Securities issued by that person;

(2) all obligations issued or assumed by that person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(3) all Capital Lease Obligations and Purchase Money Obligations of that person; and

(4) all Contingent Liabilities of that person in respect of any of the foregoing;

"Material Subsidiary" means, as at any date, a Designated Subsidiary,

(1) the total assets of which represent more than 10% of the total assets of the company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of the company; or

(2) the total revenues of which represent more than 10% of the total revenues of the company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of the company;

"Obligations" means, without duplication, with respect to any person, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of that person as of the date at which Obligations are to be determined, other than Preferred Securities issued by that person; and all Contingent Liabilities of that person in respect of any of the foregoing;

"Preferred Securities" means:

(1) securities which on the date of issue by a person (a) have a term to maturity of more than 30 years, (b) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of that person outstanding on that date, (c) entitle that person to satisfy the obligation to pay the principal or face amount by issuing common shares, (d) entitle that person to defer the payment of interest for more than four years without causing an event of default to occur, and (e) entitle that person to satisfy the obligation to make payments of interest by issuing common shares; and

(2) shares of any class in the capital of a corporation or securities representing ownership interests in any person other than a corporation which, in either case, are not common shares;

"Principal Property" means any of the company's and its subsidiaries' fixed assets used for the transmission, transformation and distribution of electricity in Ontario as of June 4, 2001 (the date of the Trust Indenture);

"Purchase Money Mortgage" means any security interest, mortgage, pledge, charge or other encumbrance created, issued or assumed by the company or a Designated Subsidiary to secure a Purchase Money Obligation; provided that the security interest, mortgage, pledge, charge or other encumbrance is limited to the property (including associated rights) acquired, constructed, installed or improved using the funds advanced to the company or a Designated Subsidiary in connection with that Purchase Money Obligation;

"Purchase Money Obligation" means Indebtedness of the company or a Designated Subsidiary incurred or assumed to finance the purchase price, in whole or in part, of any property (except any Indebtedness which constitutes a Funded Obligation and which was incurred or assumed to finance the purchase price, in whole or in part, of any shares, bonds or other securities) or incurred to finance the cost, in whole or in part, of construction or installation of or improvements to any real property or fixtures provided that such Indebtedness is incurred or assumed within 24 months after the purchase of such real property or fixtures or the completion of such construction, installation or improvements, as the case may be, and includes any extension, renewal or refunding of any such Indebtedness, so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"Security Interest" means any assignment, mortgage, charge (whether fixed or floating), hypothec, pledge, lien, or other encumbrance on or interest in property or assets that secures payment of Indebtedness or Obligation;

"Total Consolidated Capitalization" means, at any time and from time to time, without duplication, the sum of (1) the principal amount of all Consolidated Funded Obligations at the time outstanding, and (2) the total share capital of the company at the time outstanding, based upon the stated capital on the books of the company, and (3) the principal amount of all outstanding Preferred Securities referred to in clause (1) of the definition of "Preferred Securities" plus the total amount of (or less the amount of any net deficits in) the contributed or capital surplus of the company and the retained earnings of the company and all Designated Subsidiaries in accordance with GAAP after adding back the amount shown on the consolidated balance sheet of the company and its Designated Subsidiaries for minority interests applicable to Designated Subsidiaries and eliminating all intercorporate items, plus the amount of any premium on capital of the company not included in its surplus, and less the amount, if any, by which the capital account of the company or the consolidated capital surplus account of the company and all Designated Subsidiaries (determined in the manner described above) has at any time been increased as a result of any write-up in the value of the shares of a subsidiary which is not a Designated Subsidiary to reflect the equity of the company in its retained earnings or otherwise, or as a result of a restatement of the amount at which any other assets of the company or any Designated Subsidiary are recorded on its books. The amount of Total Consolidated Capitalization of the company and all Designated Subsidiaries at any time shall be ascertained in Canadian dollars; and

"Wholly-Owned Designated Subsidiary" means a Designated Subsidiary, all of the outstanding shares in the capital of which are owned, directly or indirectly, by or for the company and/or by or for one or more other Wholly-Owned Designated Subsidiaries.

Global Notes

Notes may be issued in the form of fully registered global notes ("Global Notes") held by, or on behalf of, CDS Clearing and Depository Services Inc. ("CDS") or another corporation performing similar services that is acceptable to the Trustee (the "Depository") as custodian of the Global Notes and, in such event, Notes will be registered in the name of the Depository or its nominee (a "Nominee"). Where CDS acts as Depository for a series of Notes, The Depositary Trust Company ("DTC"), Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear") and Clearstream Banking, société anonyme ("Clearstream, Luxembourg"), in each case as direct or indirect participants in CDS, will record beneficial ownership of such series of Notes on behalf of their respective accountholders or participants, to the extent the company makes such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg, as applicable (and the company specifies as such in the prospectus supplement or pricing supplement with respect to the particular series of Notes).

Purchasers of Notes represented by Global Notes will not receive Notes in definitive form ("Definitive Notes"). Instead, ownership of such Notes will be constituted through beneficial interests in the Global Notes, and will be represented through book-entry accounts of institutions (including the Dealers), as direct and indirect participants of the Depository ("participants") which, to the extent the Depository is CDS, may include DTC, Euroclear and Clearstream, Luxembourg to the extent applicable as noted above, acting on behalf of the beneficial owners of such Notes. Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Dealer or other person from or through whom the Note is purchased in accordance with the practices and procedures of such Dealer or other person. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

If Global Note(s) are issued and the Depository notifies the company that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be depository and the company and the Trustee are unable to locate a qualified replacement, or if the company elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes.

DTC, Euroclear and Clearstream, Luxembourg

Where CDS acts as Depository for a series of Notes, to the extent the company makes such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg (and the company specifies as such in the prospectus supplement or pricing supplement with respect to such series of Notes), holders may hold such series of Notes through the accounts maintained by DTC, Euroclear or Clearstream, Luxembourg, as applicable, as participants in CDS only if they are participants of those systems, or indirectly through organizations which are participants of those systems.

In such case, DTC, Euroclear and Clearstream, Luxembourg will hold omnibus book-entry positions on behalf of their participants through customers' securities accounts in their respective depositaries which in turn will hold such positions in customers' securities accounts in the names of the nominees of the depositaries on the books of CDS. All securities in DTC, Euroclear and Clearstream, Luxembourg are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts.

Transfers of such Notes by persons holding through Euroclear or Clearstream, Luxembourg participants, as applicable, will be effected through CDS, in accordance with CDS rules, on behalf of the relevant European international clearing system by its depositaries; however, such transactions will require delivery of transfer instructions to the relevant European international clearing system by the participant in such system in accordance with its rules and procedures and within its established deadlines (European time). The relevant European international clearing system will, if the transfer meets its requirements, deliver instructions to its depositaries to take action to effect the transfer of the Notes on its behalf by delivering Notes through CDS and receiving payment in accordance with its normal procedures for next-day funds settlement. Payments with respect to the Notes held through Euroclear or Clearstream, Luxembourg will be credited to the cash accounts of Euroclear participants or Clearstream, Luxembourg participants in accordance with the relevant system's rules and procedures, to the extent received by its depositaries.

All information in this short form prospectus concerning CDS, DTC, Euroclear and Clearstream, Luxembourg, reflects the company's understanding of the policies of such organizations which may change at any time without notice.

Fixed Rate Notes

Each Fixed Rate Note will bear interest from its original issue date at the rate per annum on the face thereof until the principal amount thereof is paid or made available for payment. Interest on a Fixed Rate Note will be calculated and payable monthly, quarterly, semi-annually or annually in arrears on the dates specified in such Fixed Rate Note, or other such dates as may be agreed to between the purchaser of the Note and the company (each, an "Interest Payment Date") and at maturity or upon earlier redemption or repayment. Interest Payment Dates will be set forth in the applicable prospectus supplement or pricing supplement for the Fixed Rate Note. Each payment of interest in respect of an Interest Payment Date will include interest accrued to but excluding such Interest Payment Date.

Floating Rate Notes

Each Floating Rate Note will bear interest from its original issue date at rates described in the Floating Rate Note and specified in the applicable prospectus supplement or pricing supplement.

The rate of interest on each Floating Rate Note will be reset monthly, quarterly, or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Interest on each Floating Rate Note will be payable monthly, quarterly or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Unless otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement, the company will be the calculation agent with respect to the Floating Rate Notes. Upon request of the holder of any Floating Rate Note, the company will provide the interest rate then in effect.

Payment of Interest and Principal

Interest on each interest bearing Note will be payable on such periodic basis or at maturity and on such date or dates as may be agreed upon by the company and the purchaser of the Note. Payments of interest on each interest bearing Definitive Note will be made by cheque payable on the interest payment date and mailed to the address of, or if so directed by the holder, funds representing the interest payable will be forwarded by electronic funds transfer on the interest payment date to the account of, the holder appearing on the registers maintained by Computershare Trust Company of Canada, as registrar and transfer agent (the "Transfer Agent", which term shall include such other registrar or transfer agent as may from time to time be appointed by the company) at the close of business in the City of Toronto on the tenth business day (with "business day" being a day other than Saturday, Sunday, or a day on which financial institutions in Toronto, Ontario are authorized or obligated by law or regulation to close) prior to the interest payment date or such other day specified to the Trustee by the company and reflected in a Supplemental Indenture for a particular series of Notes. Payment of principal will be made at any branch in Canada of the bank designated in a Definitive Note against surrender of the Note.

Payment of interest and principal on each Global Note will be made to the Depository or the Nominee, as the case may be, as the registered holder of the Global Note. Interest payments on Global Notes will be made by wire transfer no later than the date interest is payable. Principal payments on Global Notes will be made by wire transfer on the maturity date delivered to the Depository or the Nominee, as the case may be, at maturity against receipt of the Global Note. As long as the Depository or the Nominee is the registered owner of a Global Note, the Depository or the Nominee, as the case may be, will be considered the sole owner of the Global Note for the purposes of receiving payment on the Note and for all other purposes under the Trust Indenture and the Note.

The company expects that the Depository or Nominee, upon receipt of any payment of principal or interest in respect of a Global Note, will credit participants' accounts, on the date principal or interest is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or the Nominee. The company also expects that such payments of principal and interest by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name" and will be the responsibility of such participants. The responsibility and liability of the company and the Trustee in respect of Notes represented by Global Notes is limited to making payment of any principal and interest due on such Global Notes to the Depository or the Nominee.

Payments of interest and principal will be made in the currency in which the Note is denominated unless otherwise specified in the applicable prospectus supplement or pricing supplement.

If the payment date for any amount of principal or interest on any Note is not, at the place of payment, a business day such payment will be made on the next business day and the holder of such Note shall not be entitled to any further interest or other payment in respect of such delay.

Transfers

The registered holder of a Definitive Note may transfer such Note upon payment of taxes incidental thereto, if any, by executing the form of transfer provided on the reverse side of the Note and surrendering the Note to the Transfer Agent at its principal office in the City of Toronto, upon which one or more new Definitive Notes will be issued in authorized denominations in the same aggregate principal amount as the Note so transferred, registered in the name or names of the transferee or transferees.

Transfers of beneficial ownership in Notes represented by Global Notes will be effected through records maintained by the Depository for such Global Notes or the Nominee (with respect to the interest of participants) and on the records of participants (with respect to the interest of beneficial owners other than participants). Beneficial owners of an interest in a Note represented by a Global Note who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interests in Global Notes, may do so only through participants in the Depository's book-entry system. A purchaser's interest in a Note represented by a Global Note will only be exchangeable for Definitive Notes in the limited circumstances set forth under the heading "Global Notes" above and in accordance with the procedures established by the Depository or the Nominee.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest therein other than through a participant may be limited due to the lack of a physical certificate.

No transfer of a Note will be registered during the 10 business days immediately preceding any date fixed for payment of interest on such Note or payment of the principal amount thereof.

PLAN OF DISTRIBUTION

The Notes may be offered for sale severally and on a continuous basis by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to an agreement dated March 8, 2018, among such Dealers and the company (the "Dealer Agreement") or such other Dealers as may be selected from time to time by the company, in each case acting as agent of the company or as principal. Where the Notes are offered by the Dealer(s) as agent(s), the commission payable by the company shall be agreed from time to time between the company and any such Dealer(s). Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between the company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to the company. The commission payable in connection with sales of Notes shall be no higher than 1.5% and shall be set forth in a prospectus supplement or pricing supplement that shall accompany this short form prospectus. The company has agreed to reimburse the Dealers for certain expenses and to indemnify each Dealer against certain liabilities including liabilities under applicable Canadian securities laws.

The company may also offer the Notes directly to potential purchasers at prices and upon terms negotiated between the purchaser and the company.

The company and, if applicable, the Dealers, reserve the right to reject any offer to purchase the Notes in whole or in part. The company also reserves the right to withdraw, cancel or modify the offering of the Notes under this short form prospectus without notice. In addition, the obligations of a Dealer to purchase any particular issue of

Notes as principal may be terminated at the discretion of the Dealer upon the occurrence of certain stated events as set out in detail in the Dealer Agreement, including (i) any investigation or proceeding is commenced or order is issued under a statute of Canada or the United States (other than investigations or proceedings based on the activities of the Dealer), or there is a change of law, that operates to prevent or restrict trading in or distribution of the Notes, (ii) any material change in the business, affairs, operations, assets, liabilities, capital or control of the company and its subsidiaries which, in the reasonable opinion of the Dealer, could be expected to have a significant adverse effect on the market price or value of the Notes; (iii) certain events affecting the state of the financial markets or the business, operations or affairs of the company and its subsidiaries; and (iv) certain events of downgrade or potential downgrade of credit ratings on the company's long-term debt securities. However, the Dealers are obligated to take up and pay for all Notes of a particular issue if any of the Notes of that issue are purchased under the Dealer Agreement by the Dealers as principal.

In connection with any offering of Notes, the Dealers may, when acting as an agent or purchasing as principal, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Dealers may from time to time purchase and sell the Notes in the secondary market but are not obliged to do so. Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which Notes may be resold and purchasers may not be able to resell Notes purchased under this short form prospectus. The offering price and other selling terms for any sales in the secondary market may, from time to time, be varied by the Dealers.

The offering of Notes hereunder is directed only to residents of the provinces of Canada and in the United States in certain transactions exempt from the provisions of the United States Securities Act of 1933, as amended (the "Securities Act"). The Notes have not been and will not be registered under the Securities Act or any state securities laws and may not be offered or sold within the United States except to "qualified institutional buyers" in reliance upon Rule 144A under the Securities Act. In addition, until 40 days after the commencement of the offering of an issue of Notes, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with an exemption under the Securities Act.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of the HOI Lenders which are lenders to the company under the HOI Credit Facility, and BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of the HOL Lenders which are lenders to HOL under the HOL Credit Facility. As of March 8, 2018, there is no outstanding indebtedness under the HOI Credit Facility or the HOL Credit Facility. Proceeds from the sale of particular series or issues of Notes in which such Dealers are acting as principals or agents may be used to repay indebtedness under the HOI Credit Facility or any future credit facility to which the company may be a party with one or more of the Lenders and may be indirectly used to repay indebtedness under the HOL Credit Facility. Consequently, if and when there is outstanding indebtedness to any of the Lenders under such facilities, the company may be considered a connected issuer of those Dealers who are affiliates of such Lenders for purposes of the securities laws of certain Canadian provinces. The decision to distribute the Notes will be made by the company and the terms and conditions of distribution will be determined through negotiations between the company and the Dealers. The Lenders will not have any involvement in such decision or determination. As of the date hereof, the company is in compliance with the terms of the HOI Credit Facility. Other than payment of their portion of the commissions, if applicable, or as set forth above in respect of the HOI Credit Facility and/or the HOL Credit Facility, none of the proceeds of such offerings of Notes will be applied, directly or indirectly, for the benefit of BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. or their affiliates. See "Use of Proceeds".

USE OF PROCEEDS

The net proceeds from the sale of Notes will be added to the general funds of the company and, together with funding from other sources, including internally generated funds and other external financings, will be used to finance the company's working capital requirements, to repay outstanding bank loans (which may include indebtedness under the HOI Credit Facility), debentures, notes or other Indebtedness, to make advances to subsidiaries of the company, to finance the company's capital expenditure program, to make acquisitions and for other general corporate purposes. Where appropriate, a prospectus supplement or pricing supplement will contain more specific information about the use of proceeds from each sale of Notes. All expenses relating to an offering of Notes, including any compensation paid to the Dealers, will be paid out of the company's general funds or netted out of the proceeds of the particular offering of Notes. The company may from time to time issue debt instruments and incur additional Indebtedness otherwise than through the issue of Notes pursuant to this short form prospectus.

PRIOR SALES

No medium term notes or other securities that are convertible or exchangeable into medium term notes have been issued or sold by the company in the 12-month period prior to the date hereof.

TRADING PRICE AND VOLUME

The company's Series 28 Notes (2.78%) due 2018 (the "Series 28 Notes") are listed on the New York Stock Exchange under the symbol "HYDO18". The company's Series 29 Notes (4.59%) due 2043 (the "Series 29 Notes") are listed on the New York Stock Exchange under the symbol "HYDO43". There have been no reported trades of the Series 28 Notes or the Series 29 Notes on the New York Stock Exchange since their date of issuance.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

General

The following summary describes the principal Canadian federal income tax considerations generally applicable to a purchaser who acquires Notes, including entitlement to all payments thereunder, as a beneficial owner pursuant to this short form prospectus and who, at all relevant times, for purposes of the application of the Tax Act, deals at arm's length with the company and holds Notes as capital property (a "Holder"). Generally, Notes will be capital property to a purchaser provided the purchaser does not acquire or hold those Notes in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain purchasers resident in Canada may be entitled to make or may have already made the irrevocable election permitted by subsection 39(4) of the Tax Act the effect of which may be to deem to be capital property any Notes (and all other "Canadian securities", as defined in the Tax Act) owned by such purchasers in the taxation year in which the election is made and in all subsequent taxation years. Purchasers whose Notes might not otherwise be considered to be capital property should consult their own tax advisors concerning this election.

This summary is based on the current provisions of the Tax Act and on counsel's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency published in writing prior to the date hereof. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments") and assumes that all Proposed Amendments will be enacted in the form proposed. However, no assurances can be given that the Proposed Amendments will be enacted as proposed, or at all. This summary does not otherwise take into account or anticipate any changes in law or administrative policy or assessing practice whether by legislative, administrative or judicial action nor does it take into account tax legislation or considerations of any province, territory or foreign jurisdiction, which may differ from those discussed herein.

Depending upon the terms of any offering of the Notes as set forth in an applicable prospectus supplement or pricing supplement, the Canadian federal income tax considerations applicable to a Holder of the Notes at the time of such offering may be different from those described below. Such considerations may be described more particularly when such Notes are offered (and then only to the extent material) in the prospectus supplement or pricing supplement related thereto. In the event the Canadian federal income tax considerations are described in such prospectus supplement or pricing supplement, the description below will be superseded by the description in the prospectus supplement or pricing supplement to the extent indicated therein.

This summary is of a general nature only and is not, and is not intended to be, legal or tax advice to any particular purchaser. This summary is not exhaustive of all Canadian federal income tax considerations.

Accordingly, prospective purchasers of Notes should consult their own tax advisors having regard to their own particular circumstances.

Currency Conversion

For purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of the Notes issued in a non-Canadian currency must be converted into Canadian dollars based on exchange rates as determined in accordance with the Tax Act. The amount of interest required to be included in the income of, and capital gains or capital losses realized by, a Holder may be affected by fluctuations in the applicable exchange rate.

Holders Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act, is, or is deemed to be, resident in Canada, is not affiliated with the company and has not entered into and will not enter into, with respect to the Notes acquired by such Holder, a "derivative forward agreement" as defined in the Tax Act (a "Resident Holder").

This portion of the summary is not applicable to (i) a purchaser an interest in which is a "tax shelter investment", (ii) a purchaser that is, for purposes of certain rules (referred to as the mark-to-market rules) applicable to securities held by financial institutions, a "financial institution", or (iii) a purchaser that reports its "Canadian tax results" in a currency other than Canadian currency, each as defined in the Tax Act. Such purchasers should consult their own tax advisors.

Taxation of Interest and other Amounts

A Resident Holder that is a corporation, partnership, unit trust or any trust of which a corporation or partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on a Note that accrues or is deemed to accrue to such Resident Holder to the end of that taxation year, or becomes receivable or is received by the Resident Holder before the end of such year, to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year.

Any other Resident Holder, including an individual and a trust of which neither a partnership nor a corporation is a beneficiary, will be required to include in computing its income for a taxation year any interest on a Note that is received or receivable by such Resident Holder in that taxation year (depending on the method regularly followed by the Resident Holder in computing its income) to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year. Such a Resident Holder may also be required to include in the Resident Holder's income, for any taxation year that includes an "anniversary day" (as defined in the Tax Act) of the Note, any interest, or amount that is considered for the purposes of the Tax Act to be interest, on the Note which accrues to the Resident Holder to the end of such day, to the extent that such interest was not otherwise included in computing the Resident Holder's income for the year or a preceding taxation year. For this purpose, an "anniversary day" means the day that is one year after the day immediately preceding the date of issue of a Note, the day that occurs at every successive one year interval from that day and the day on which a Note is disposed of.

Where a Resident Holder is required to include an amount on account of interest on a Note that accrued in respect of the period prior to its date of acquisition, the Resident Holder will be entitled to a deduction in computing income of an equivalent amount. The adjusted cost base to the Resident Holder of the Note will be reduced by the amount which is so deducted.

Any amount paid by the company to a Resident Holder as a premium, penalty or bonus because of early repayment of all or part of the principal amount of a Note before its maturity will be deemed to be received by the Resident Holder as interest on the Note at that time and will be required to be included in computing the Resident Holder's income as described above, to the extent such amount can reasonably be considered to relate to, and does not exceed the value at the time of payment of, interest that, but for the repayment, would have been paid or payable by the company on the Note for a taxation year of the company ending after that time.

Disposition of Notes

On a disposition or deemed disposition of a Note, including a redemption, repayment prior to or on maturity or repurchase, a Resident Holder will generally be required to include in computing its income for the taxation year in which the disposition occurs the amount of interest that has accrued, or that has been deemed to have accrued, on the Note to that time except to the extent that such amount has otherwise been included in the Resident Holder's income for the year or a preceding taxation year.

Generally, on a disposition or deemed disposition of a Note, including a redemption, payment on maturity or repurchase, a Resident Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any amount included in the Resident Holder's income as interest (as described above) and any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Resident Holder of the Note immediately before the disposition or deemed disposition. Generally, a Resident Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "taxable capital gain") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Resident Holder is required to deduct one-half of the amount of any capital loss (an "allowable capital loss") realized in a taxation year from taxable capital gains realized by the Resident Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years.

Holders Not Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act (1) is not, and is not deemed to be, resident in Canada, (2) deals at arm's length with any transferee resident (or deemed to be resident) in Canada to whom the Holder disposes of the Notes, and (3) does not use or hold the Notes in a business carried on or deemed to be carried on in Canada (a "Non-Resident Holder"). Special rules, which are not discussed in this summary, may apply to a Non-Resident Holder that is an insurer that carries on an insurance business in Canada and elsewhere.

This summary assumes that no interest paid on the Notes will be in respect of a debt or other obligation to pay an amount to a person with whom the company does not deal at arm's length, within the meaning of the Tax Act.

This portion of the summary is not applicable to a Non-Resident Holder that is a "specified shareholder" (as defined in subsection 18(5) the Tax Act) of the company or that does not deal at arm's length for purposes of the Tax Act with a "specified shareholder" of the company. Generally, for this purpose, a "specified shareholder" is a shareholder that owns or is deemed to own, either alone or together with persons with which the shareholder does not deal at arm's length for purposes of the Tax Act, shares of the company's capital stock that either (i) give such shareholders 25% or more of the votes that could be cast at an annual meeting of the shareholders or (ii) have a fair market value of 25% or more of the fair market value of all of the issued and outstanding shares of the company's capital stock. Such Non-Resident Holders should consult their own tax advisors.

No Canadian withholding tax will apply to interest, principal or premium paid or credited to a Non-Resident Holder by the company on a Note or to the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase, unless all or any portion of such interest is contingent or dependent on the use of or production from property in Canada or is computed by reference to revenue, profit, cash flow, commodity price or any other similar criterion or by reference to dividends paid or payable to shareholders of any class of shares of the capital stock of a corporation (the "Participating Debt Interest"). The interest on Fixed Rate Notes, and on Floating Rate Notes in respect of which the payment of interest is determined by reference to published rates of a central banking authority or one or more financial institutions, or to recognized market benchmark interest rates or to interest rates on Government of Canada bonds is not Participating Debt Interest and, as such, no Canadian withholding tax will apply to interest paid or credited or deemed to be paid or credited on such Notes.

Generally, no other Canadian federal taxes on income or gains will be payable by a Non-Resident Holder on interest, principal or premium paid or credited to a Non-Resident Holder by the company on a Note or on the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase.

RISK FACTORS

In addition to the other information contained and incorporated by reference in this short form prospectus, a purchaser should consult its own financial and legal advisors and should carefully consider the following risk factors before investing in the Notes. Notes will not be an appropriate investment for a purchaser if the purchaser does not understand the terms of the Notes or financial matters in general. A purchaser should not purchase Notes unless the purchaser understands, and can bear, all of the investment risks involving the Notes. For a discussion of the risks to which the company's business and industry are subject, please see the section entitled "Risk Factors" in the company's annual information form and the section entitled "Risk Management and Risk Factors" in the company's management's discussion and analysis. In addition to those risks, an investment in the Notes is subject to the following additional risks:

The Company Must Receive Dividends and Other Payments from Its Subsidiaries in Order to Make Payments to Holders of Notes

The company is a holding company that has no significant assets or operations other than the debt and equity of its subsidiaries. The company's most significant subsidiary is Hydro One Networks Inc., a regulated wholly-owned subsidiary which owns and operates the company's transmission and distribution assets. The company is dependent on dividends, interest, loans and other payments from this and other subsidiaries to meet its debt service and other obligations.

The company's subsidiaries are separate legal entities and have no obligation to pay any amounts due under the Notes and, except for their respective obligations under existing intercompany debt obligations owing to the company, have no obligation to make funds available to the company, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Notes. In the event of bankruptcy, liquidation or reorganization of any of the company's subsidiaries, the creditors of these subsidiaries will generally be entitled to the payment of their claims before any assets are made available for distribution to the company, except to the extent that the company is recognized as a creditor of those subsidiaries.

The company's subsidiaries currently are not restricted in terms of their ability to pay dividends or make other payments to the company, other than by solvency provisions under generally applicable Ontario corporate law or partnership law, as applicable. However, they could become so restricted in the future by, among other things, other laws as well as agreements to which they may become parties in the future.

The Notes Are Not Secured

The Notes will not be secured by any of the assets of the company. If the company were involved in any bankruptcy, dissolution, liquidation or reorganization, the holders of secured indebtedness of the company would have a claim on the assets securing such indebtedness that would rank prior to the claim of holders of Notes on such assets. Holders of secured indebtedness of the company also would have a claim that ranks *pari passu* with the claim of holders of Notes on the remaining assets of the company to the extent that such security did not satisfy such secured indebtedness in full.

There May Be No Trading Market for the Notes and if One Develops, the Notes May Be Subject to Trading Price Fluctuations

The Notes are new issues of securities for which, unless otherwise indicated in a prospectus supplement or pricing supplement, there is no existing trading market. The company cannot predict whether any active trading market will develop for the Notes, even if the Notes are listed on a stock exchange.

Even if an active trading market develops for the Notes, the Notes could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, the company's results of operations and financial position, the ratings assigned to the Notes and the company's other debt securities, and the markets for similar debt securities.

If a holder of Notes sells any Notes before their maturity, such holder may have to do so at a substantial discount from the issue price, and as a result such holder may suffer substantial losses.

Investors May Be Subject to the Risk of Exchange Rate Fluctuations

An investment in Notes that are denominated or payable in a currency other than the functional currency of the investor entails significant risks that are not associated with a similar investment in a security denominated in the functional currency of the investor. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the two currencies, the possibility of the imposition or modification of foreign exchange controls in respect of one or both of the currencies, and potential illiquidity in the secondary market. These risks generally depend on circumstances over which the company has no control including political events, government policy and macroeconomic conditions. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a prospectus supplement or pricing supplement.

In certain circumstances, investors may receive payments in currencies other than the currency in which the Notes are denominated. This may subject investors to exchange rate risk in respect of the conversion of principal and interest payments on the Notes from the currency in which the Notes are denominated to the currency of the payment which they receive, and they may also bear any costs of conversion incurred in connection therewith. For example, to the extent the company makes a series of Notes eligible with DTC, investors who hold such Notes through DTC where CDS acts as Depository and who do not elect to receive principal and interest payments in Canadian dollars will be subject to exchange rate risk in respect of the conversion of Canadian dollar principal and interest payments to U.S. dollars, and will also bear any costs of conversion incurred in connection therewith.

The Notes will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Note may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

This short form prospectus does not describe all the risks of an investment in the Notes denominated or payable in a currency other than an investor’s functional currency, and prospective investors should consult their own financial and legal advisor as to the risks entailed with respect thereto. Notes denominated in currencies other than an investor’s functional currency are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

Changes in Interest Rates Will Affect the Market Price or Value of the Notes

Generally, the market price or value of the Notes will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the company which may adversely affect its creditworthiness. It is impossible to predict whether interest rates will rise or fall.

Changes in Creditworthiness or Credit Ratings May Affect the Market Price or Value of the Notes

The perceived creditworthiness of the company and changes in credit ratings of the Notes may affect the market price or value and the liquidity of the Notes. In addition, negative changes in the company’s credit rating may affect the credit ratings of the Notes.

Floating Rate Notes Are, By Their Nature, Uncertain

Investments in Floating Rate Notes entail risks not associated with investments in Fixed Rate Notes. The resetting of the applicable rate on a Floating Rate Note may result in a lower interest rate as compared to a Fixed Rate Note issued at the same time. The applicable rate on a Floating Rate Note will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which the company has no control.

The Notes May Be Subject to Early Redemption

Depending on the terms of the Notes, the company may have the right to redeem them, or the Notes may be automatically redeemable under some circumstances. If the Notes are redeemed, depending on the market conditions at the time of redemption, a holder of Notes may not be able to reinvest the redemption proceeds in a security with a comparable return. Potential purchasers should consider reinvestment risk in light of other investments available at that time.

In addition, any optional redemption feature giving the company the right to redeem Notes may limit their market value. Where the Notes include such a feature, during any period when the company may elect to redeem Notes prior to the stated maturity date, the market value of those Notes generally will not rise substantially above the price at which they can be redeemed.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed upon by Osler, Hoskin & Harcourt LLP for the company and by Blake, Cassels & Graydon LLP for the Dealers. The partners and associates of Osler, Hoskin & Harcourt LLP and Blake, Cassels & Graydon LLP beneficially own, directly or indirectly, less than one percent of the securities of the company or any associate or affiliate of the company.

AUDITORS, REGISTRAR AND TRANSFER AGENT

KPMG LLP, Chartered Professional Accountants, Licensed Public Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario M5H 2S5, is the auditor of the company and has confirmed that it is independent of the company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

Registers for the registration and transfer of the Notes issued in registered form are kept at the principal offices of the Transfer Agent in the City of Toronto.

PURCHASERS' STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revision of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AGENT FOR SERVICE OF PROCESS IN CANADA

Kathryn Jackson, a director of the company, resides outside of Canada. Ms. Jackson has appointed Hydro One Inc., 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5, Canada, as her agent for service of process in Canada. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or that resides outside of Canada, even if the party has appointed an agent for service of process.

CERTIFICATE OF HYDRO ONE INC.

Dated: March 8, 2018

This short form prospectus, together with the documents incorporated in this short form prospectus by reference, will, as of the date of the last supplement to this short form prospectus relating to the securities offered by this short form prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada.

(Signed) Mayo Schmidt President and Chief Executive Officer	(Signed) Paul Dobson Chief Financial Officer

On behalf of the Board of Directors:

(Signed) David Denison Director	(Signed) Philip Orsino Director

CERTIFICATE OF DEALERS

Dated: March 8, 2018

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this short form prospectus by reference will, as of the date of the last supplement to this short form prospectus relating to the securities offered by this short form prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

BMO NESBITT BURNS INC.	CASGRAIN & COMPANY LIMITED	CIBC WORLD MARKETS INC.
By: (Signed) Grant Williams	By: (Signed) Stephen McHarg	By: (Signed) Scott Burrows
DESJARDINS SECURITIES INC.	LAURENTIAN BANK SECURITIES INC.	NATIONAL BANK FINANCIAL INC.
By: (Signed) Ryan Godfrey	By: (Signed) Thomas Berky	By: (Signed) John Carrique
RBC DOMINION SECURITIES INC.	SCOTIA CAPITAL INC.	TD SECURITIES INC.
By: (Signed) Rob Brown	By: (Signed) Greg Lawrence	By: (Signed) Mark Laing

HYDRO ONE LIMITED - HISTORICAL YEAR ANNUAL REPORT (2017)

Included in this exhibit are Hydro One Limited’s Annual Reports:

- Attachment 1: 2017 Annual Report

Delivering a
POWERFUL FUTURE

HYDRO ONE LIMITED 2017 ANNUAL REPORT

hydro One

Hydro One Limited (Hydro One) is Ontario's largest electricity transmission and distribution provider with more than 1.3 million valued customers, $25.7 billion in assets and annual revenues of approximately $6 billion. Our team of approximately 7,400 skilled and dedicated regular and non-regular employees proudly and safely serves suburban, rural and remote communities across Ontario through our approximately 30,000 circuit kilometres of high-voltage transmission and approximately 123,000 circuit kilometres of primary low-voltage distribution networks. Hydro One is committed to the communities we serve, and has been rated as the top utility in Canada for its corporate citizenship, sustainability, and diversity initiatives. We are one of only five utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association. We also provide advanced broadband telecommunications services on a wholesale basis utilizing our extensive fibre optic network. Hydro One's common shares are listed on the Toronto Stock Exchange (TSX: H).

Contents

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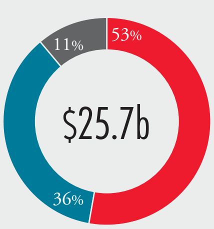
This report contains forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our Company. Words such as "expect" and "will" are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

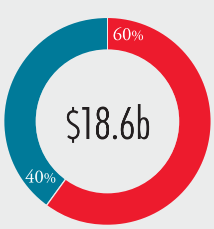
FINANCIAL HIGHLIGHTS

Year ended December 31 (millions of dollars, except as otherwise noted)	2017	2016
Revenues	**5,990**	6,552
Purchased power	**2,875**	3,427
Revenues, net of purchased power[1]	**3,115**	3,125
Operation, maintenance and administration costs (OM&A)	**1,066**	1,069
Depreciation and amortization	**817**	778
Financing charges	**439**	393
Income tax expense	**111**	139
Net income attributable to common shareholders of Hydro One	**658**	721
Basic earnings per common share (EPS)	**$1.11**	$1.21
Diluted EPS	**$1.10**	$1.21
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$1.17**	$1.21
Diluted Adjusted EPS[1]	**$1.16**	$1.21
Net cash from operating activities	**1,716**	1,656
Funds from operations (FFO)[1]	**1,579**	1,494
Capital investments	**1,567**	1,697
Assets placed in-service	**1,592**	1,605
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289
Debt to capitalization ratio[2]	**52.9%**	52.6%

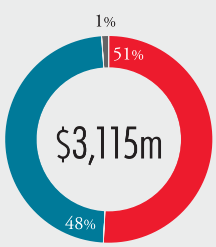
Total Assets



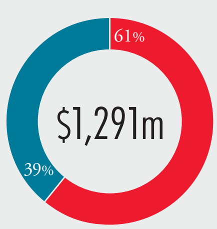
Rate Base



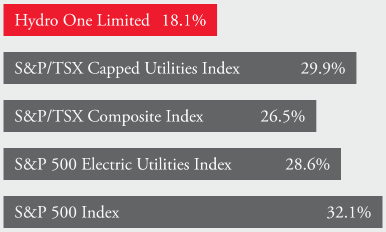
Revenues
(Net of purchased power costs)



Regulated Earnings
(Before financing charges and income taxes)



Total Shareholder Return (TSR)
November 5, 2015 IPO to December 31, 2017



• Transmission • Distribution • Other

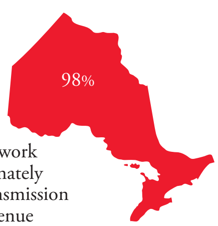
1. See section Financial Report (starting on page 31) on "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.
2. Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

5 REASONS to Invest in Hydro One

INVESTING IN HYDRO ONE OFFERS A UNIQUE OPPORTUNITY TO PARTICIPATE IN THE TRANSFORMATION OF A PREMIUM LARGE-SCALE UTILITY

Nº 1

Everyone Uses Electricity
We are one of the largest regulated electric utilities in North America. We own and operate an extensive system of transmission and distribution networks in Canada's most populated province with no material exposure to commodity prices.



Our transmission network accounts for approximately 98% of Ontario's transmission capacity based on revenue

Nº 2

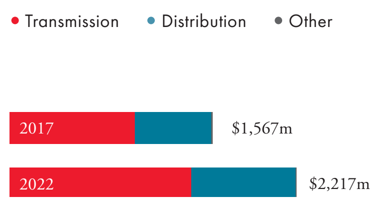
Strong Balance Sheet
Our strong investment-grade balance sheet has one of the highest quality utility credit profiles in North America.

Agency	Credit Profile Long Term/Short Term/Outlook
S&P	A / A-1/ negative
DBRS	A (high) / R-1 (low) / stable
Moody's	A3 / Prime-2 / negative

Nº 3

Predictable Growth
We offer a predictable multi-year growth profile with strong cash flows. This is the result of an expanding rate base that supports the need to upgrade and maintain our aging infrastructure.

Capital Investments
(CAD $ millions)



Nº 4

Attractive Dividend
We have an attractive dividend yield with 70–80 per cent target payout ratio and offer the opportunity for continued dividend growth.

70–80% TARGET PAYOUT RATIO

Nº 5

Forward Looking
Our highly accomplished management team has taken on the opportunity to transform the organization into a commercially oriented, performance-driven culture focused on improving productivity and customer service.

Reducing OM&A Spend
November 5, 2015 to December 31, 2017 (CAD $ millions)

CHAIR

David F. Denison
Chair of the Board
Hydro One Limited

Dear fellow shareholders,

As I look back on 2017, it is first important to acknowledge the tragic loss the Hydro One family suffered in December with the deaths of four employees. The response to that accident demonstrated the incredible strength and unity of the entire Hydro One organization as employees came together to mourn and support each other moving forward. It has also led to a re-affirmation of the paramount importance of safety in all aspects of our policies, practices and procedures.

During 2017, the Board worked closely with the management team to formulate a new long term strategy for Hydro One; our President and CEO Mayo Schmidt provides more detail about the strategy in his letter. The Board is confident that the disciplined execution of this strategy in the years ahead will create considerable value for our shareholders and other stakeholders. The pending acquisition of Avista Corporation that we announced last July is just one concrete example of the implementation of that strategy.

Successful execution relies on a talented management team. One of the key responsibilities and priorities for our Board is to ensure that we have sufficient depth of talent and experience as well as strong succession plans across our leadership team. The Board was pleased to see the ranks of our leadership team strengthened with the recently announced addition of Paul Dobson as Chief Financial Officer.

Commitment to Diversity and Inclusion
Last year, Hydro One joined the 30% Club, an international campaign aimed at achieving a minimum of 30 per cent of women represented on boards, a level we have already surpassed, and also signed the Catalyst Accord: Women on Corporate Boards in Canada. In August, Hydro One also became a signatory to the Leadership Accord on Gender Diversity in the Canadian Electricity Industry.

All of these initiatives demonstrate Hydro One's commitment to becoming a more diverse and inclusive workplace, one where all employees feel supported and included.

In conclusion, 2017 was an important year of transition for Hydro One in its evolution as a broadly held, strong performing public Company. The entire Board expresses its thanks and appreciation to all employees of Hydro One for their hard work in serving the interests of our customers and shareholders. We believe we now have the foundations in place to enhance the value we will bring to all stakeholders in the years ahead.

Thank you for your investment and continued support,

David F. Denison
Chair of the Board of Directors

Hydro One's Governance Practices

Fully Independent Board (excluding CEO)	Separate Board Chair and CEO	Director Share Ownership Guidelines	Commitment to Director Diversity	Governance Agreement with the Province	Majority Voting Policy for Directors	Annual Reviews of Board and Committee Performance

CEO

Mayo Schmidt
President and Chief Executive Officer
Hydro One Limited

Key Achievements

$114.4m
2016/2017 productivity savings[1]

5%
Dividend increase in May (to $0.22)

41% (approx.)
Transmission SAIDI[2] improvement

1st
Hydro One's Contact Centre was the first electricity service provider in Ontario to open to customers on Saturdays

90%
Customer satisfaction with contact centre agents; highest in the Company's history

1. Productivity savings achieved are as a result of operational improvements in both capital and OM&A.
2. SAIDI (System Average Interruption Duration Index) year-end 2017 performance improvement relative to a 5-year average (%).

Dear fellow shareholders,

I want to acknowledge the tragic loss we experienced on December 14th that took the lives of four of our own. The entire Hydro One family came together for the families and to support teammates in the wake of this tragedy and to commemorate the lives of James, Jeff, Darcy and Kyle. Collectively, we continue to support the grieving families and loved ones of our four men. The health, safety, and well-being of every single person at Hydro One are paramount to me, this Company, and to all of our people.

While we were also faced with a number of industry challenges including: rising interest rates, a lower regulated return on equity that impacted transmission and distribution revenues and extended unseasonably milder weather affecting 2017 total shareholder return; we have acted with a high degree of discipline to moderate these events and we remain committed to delivering value for our shareholders and other stakeholders.

Unveiling Our Strategy
In 2017, our Board of Directors approved Hydro One's strategy which outlines our plan to become one of North America's leading utilities.

1. Optimization and Innovation
2. Diversification
3. Growth

In 2015, our public listing was the fourth largest IPO in Canadian history. While Hydro One is now a commercially focused shareholder-owned company, we embrace the responsibility of delivering results for shareholders while caring for our people and building our customer oriented culture.

Privatization has made it possible for us to enact powerful change at Hydro One: improved customer service, acting on efficiency and productivity opportunities, and greater corporate social responsibility. We have attracted a market-leading team of professionals to drive Hydro One to further successes. As shareholders, you have the unique opportunity to participate in our transformation and to invest in a premium, large-scale utility.

In 2016, on behalf of our 1.3 million customers, we advocated to the provincial government about the need for rate relief for Customers. We inspired and led the electricity utility industry in our province to proactively reconnect vulnerable customers before the coldest months of the year. Following our lead, in October 2017, the Ontario Energy Board (OEB) announced that all electric distribution companies operating in Ontario would be required to reconnect power for vulnerable individuals and families in the winter.

2017 Accomplishments
Optimization and Innovation: We have delivered approximately $114.4 million in productivity savings in 2016 and 2017. We continue to review processes and implement initiatives across our entire platform to drive efficiencies and generate cost savings as our contribution to critical infrastructure.

Application of technology in the field, and the elimination of a paper-based system through Move-to-Mobile has provided our people with the necessary tools to optimize both volume and quality of service. Fleet telematics led to a net reduction of hundreds of units in our fleet, while improving safe driving and reducing costs.

We have designed and implemented a new vegetation maintenance strategy and program called the Optimal Cycle Protocol transitioning from a 10 year cycle to a 3 year maintenance cycle to reduce safety risks, improve reliability, reduce unit cost, and improve customer satisfaction.

Customer Focus: We achieved the lowest accounts receivable balance in our history – a $40 million reduction, while achieving a reduction in customer disconnections for non-payment declining by 57% in 2017.

Through the Province's Fair Hydro Plan, a typical Hydro One residential customer will see savings on their monthly bills, of 31 per cent. We have seen significant improvement, in customer service statistics this past year, including:

- The highest customer satisfaction rate in four years for our distribution customers; and
- 10 per cent increase in transmission customer satisfaction.

Diversification: The electricity industry is transforming from a system based on large centralized generation, transmission and distribution, to a localized distributed generation systems to leverage capacity. In anticipation of this, Hydro One is developing its strategy to adapt our grid investments to reflect this new reality, and to provide new energy services that customers are demanding.

Growth: We announced our intention to acquire Avista Corporation (Avista) to create a growing North American utility leader with a combined pro forma asset value of over CAD $34.9 billion. With Avista, Hydro One is strengthening its core by diversity of geography, regulation and service offerings to include gas distribution in a vertically integrated platform.

I would like to thank the thousands of Hydro One employees across Ontario who are committed to advocating on behalf of our customers. I also extend my gratitude to our Board of Directors for its support and confidence in Hydro One's leadership team.

Sincerely,

Mayo Schmidt

Mayo Schmidt
President and Chief Executive Officer

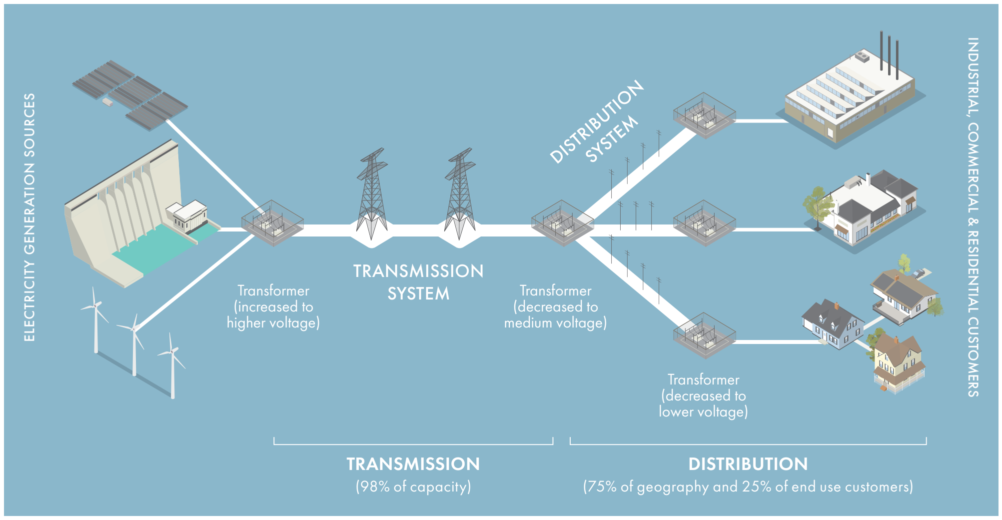
AT-A-GLANCE

ONE OF NORTH AMERICA'S LARGEST ELECTRIC UTILITIES[1]

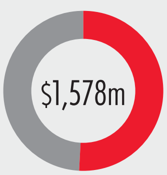
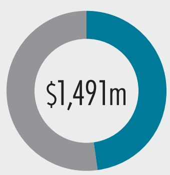
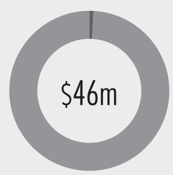
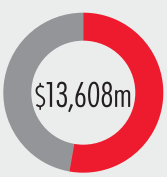
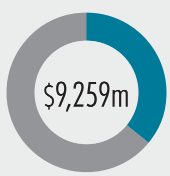
Our transmission and distribution system safely and reliably serves communities throughout Ontario. Our customers are suburban, rural and remote homes and businesses across our province.

We proudly own and operate $25.7 billion in assets and have annual revenues of approximately $6 billion.

Hydro One's Role in the Electric Power System



OUR BUSINESSES

	Transmission	Distribution	Other
Revenues (Net of Purchased Power)	 51%	 48%	 1%
Regulated	✓	✓	Unregulated
Segmented Assets	 53%	 36%	 11%
Business Description	Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to our distribution company and industrial customers across Ontario.	The Hydro One distribution system is the largest in Ontario. It consists of approximately 123,000 circuit kilometres of primary low-voltage power lines serving over 1.3 million customers.	Consists of a telecommunications business and certain corporate activities. Hydro One Telecom offers organizations a diverse, secure and highly reliable broadband connectivity solution.
Customer Segments	• Large directly connected industrial customers • Local distribution companies • Generators	• Residential and business customers • Municipal utility customers	• Data centres • Cloud service providers • Telecommunications services and public sector entities • Internet service providers • Enterprises

1. Based on assets

Key Highlights 2017

7,400 (approx.)
Skilled and dedicated regular and non-regular employees

over 1.3 million
Valued customers

$1.6b (approx.)
Capital investments

308
Transmission stations in service

$18.6b
Combined transmission and distribution rate base

30,000 (approx.)
Circuit kilometres of high-voltage transmission lines

1 of 5
Utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association

123,000 (approx.)
Circuit kilometres of primary low-voltage distribution lines

MAJOR PROJECTS

	Supply to Essex County Transmission Reinforcement	Clarington Transmission Station	East-West Tie Station Expansion
			
Description	Hydro One is constructing a new transmission station in the Municipality of Leamington and a 13-kilometre, double circuit 230 kilovolt transmission line on a new corridor to connect the station with the existing 230 kilovolt transmission line. The project is needed to provide for load growth in the Kingsville-Leamington area and to improve operational flexibility in the Windsor-Essex region in the long term.	Clarington Transmission Station involves the construction of a new 500/230 kilovolt transformer station in the city and the connection of the existing 230 kilovolt and 500 kilovolt transmission lines in the area. The station is required to ensure an adequate, safe and reliable supply of power to support the growing communities in the eastern part of the Greater Toronto Area.	Hydro One is performing station upgrades to our Wawa and Lakehead transmission stations. The upgrades are necessary to support the East-West Tie Line project, a priority project in the Province of Ontario's Long-Term Energy Plan.
Estimated Total Project Cost	$57[1] million	$267 million	$157 million
Capital Cost to Date	$52 million	$223 million	$7 million
Anticipated In-Service Date	2018	2018	2021

1. In February 2018, the estimated cost to complete the supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million

CUSTOMER FOCUS

We made great strides in 2017 to become our customers' advocates. The Hydro One of today aspires to be a more thoughtful, caring organization where the voices of our more than 1.3 million customers are heard and acted on.

Distribution Customer Satisfaction
Increased to 71 per cent in 2017, an increase of 5 per cent since 2016, largely due to strong operational performance in all functional areas, including billing, contact centre, collection and conservation.

Transmission Customer Satisfaction
Increased to 88 per cent in 2017, an increase of 10 per cent since 2016, partially attributed to enhanced customer reporting and a renewed commitment to customer advocacy.

Customer Satisfaction (%)

• Transmission • Distribution

	Distribution	Transmission
2016	66	78
2017	71	88

OUR STRATEGY FOR SUCCESS

1. OPTIMIZATION AND INNOVATION

Hydro One is transforming to achieve its vision of becoming a best-in-class, customer-centric commercial entity, with a culture of operational excellence and continuous improvement. Hydro One will execute on its strategy to transmit and distribute electricity safely and reliably in a manner that produces the greatest value for customers. Hydro One seeks to be excellent in every facet of its operations, to the benefit of its customers, employees and shareholders.

Innovation will become a focus for the Company and Hydro One plans to invest in innovation to modernize the transmission and distribution grids, improving reliability and efficiencies as well as building a platform for connecting distributed energy resources.

Move to Mobile (M2M) – The M2M project transformed work processes and implemented technology that automated the scheduling & dispatching functions, including the deployment of tablets to the field for work tracking resulting in enhanced customer service and productivity gains.

Procurement – A comprehensive spend analysis was performed in 2017. Strategic sourcing initiatives led to price reduction for materials and services as a result of consolidating spend across the Company and increasing competition among vendors.

Fleet Right Sizing – In 2017 the Hydro One fleet (transportation & work equipment was reduced by 10 per cent by leveraging telematics data that identified underutilized fleet equipment.

Optimal Cycle Protocol (OCP) – In October 2017, a state-of-the-art vegetation management program was introduced. The OCP program involves a shorter tree clearing and trimming cycle where crews focus on defects along Hydro One's vast distribution line every three years rather than full right-of-way management every eight to 10 years. In 2017, 45 per cent of outages were because of trees.

Tackling Distribution Reliability – Two primary programs will result in improved reliability. The OCP program and Distribution grid modernization both will impact reliability positively over the next few years.

Procurement

$29.5m

in procurement savings (2017)

Move-to-Mobile

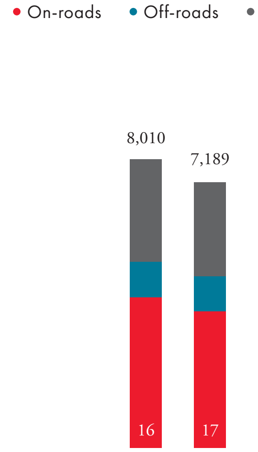
$16.9m

in savings (2017)

Fleet

10%

net reduction of number of fleet



2. DIVERSIFICATION

The electricity industry is transforming from a system based on large centralized generation, transmission and distribution, to small-scale, distributed generation, as a result of declining technology costs and customers' desire for choice in electricity supply. Hydro One's strategy is to adapt our grid investments to reflect this new reality, and to provide the new energy services that customers are demanding.

Hydro One will evaluate new businesses such as providing behind-the-meter products and services that meet requirements for resiliency, reliability, sustainability, quality and security more cost effectively than grid-only supply.

Hydro One will also seek to invest in emerging technology that focuses on innovation in the electricity sector, to identify technologies that could disrupt the Company's business, or that can enhance its business.

3. GROWTH

Through growth, we turn the impossible, possible to reach our goal of becoming the leading North American utility that customers, shareholders and the public can count on. In 2017, we laid the groundwork for future success. We pride ourselves in having a proven record of consolidating electricity utilities.

Avista – In July, we announced our partnership with Avista, where we were acquiring 100 per cent of the shares of Avista, a fully integrated regulated transmission and distribution utility headquartered in Spokane, Washington.

The acquisition, which is expected to close in 2018 following the necessary regulatory approvals, will see Hydro One and Avista create a diversified and growing North American utility leader with tremendous enterprise value.

AVISTA®

BUILDING A SUSTAINABLE FUTURE

"WE ARE COMMITTED TO RUNNING A SUSTAINABLE, SOCIALLY RESPONSIBLE BUSINESS."

MAYO SCHMIDT
PRESIDENT AND CEO

Using Resources Responsibly
Hydro One is committed to building a sustainable future for all Canadians. The sheer scale of our operations — the geographic area we cover, the million of customers we serve and economies we impact — makes it essential that we do our part. We contribute by delivering electricity that is among the cleanest, safest and most reliable in North America.

At a time of growing climate change, Hydro One continues to work to reduce our impact on ecosystems. Internally, our environmental teams collaborate with a range of Hydro One's lines of business to set the agenda, raise awareness and provide guidance on creating real change.

Over the past five years, Hydro One has undergone 103 inspections by the Ministry of the Environment and Climate Change, and by Environment and Climate Change Canada relating to our waste and polychlorinated biphenyls (PCB) storage sites, and environmental compliance approvals. Not a single inspection resulted in a charge. Indeed, we have a strong record in environmental compliance and maintain solid, co-operative relationships with regulators.

Reducing Our Impact
We operate in a highly regulated space, where federal, provincial and municipal bodies require us to assess and mitigate environmental risks. These include everything from the water and emissions we discharge, our land uses, how we dispose of waste and our impact on biodiversity. Permits and approvals are required every step of the way.

To assess, manage and mitigate these risks, Hydro One has an integrated Health, Safety and Environmental Management System (HSEMS), aligned with the ISO 14001 Environmental Management Systems framework. We expect every line of business to identify and reduce high environmental risks in their operations. Since 1999, Hydro One Remote Communities has used an Environmental Management System to reduce their environmental footprint and maintain biodiversity in the environmentally sensitive areas of the province in which they operate.

In 2017, Hydro One Networks Inc. invested $13.9 million in prevention and environmental management, emissions treatment, waste disposal, remediation, water management and environmental approvals.

2017 Achievements
- Developed a sustainability framework, outlining how other initiatives internally support this structure, including our Corporate Social Responsibility Report, HSEMS, other corporate initiatives and our corporate reporting;
- Verification of Hydro One Networks Inc.'s Scope 1 Sulfur Hexafluoride (SF_6) emissions and the verification of Hydro One Remote Communities' greenhouse gas emissions;
- Continued our efforts to further reduce greenhouse gas emissions through better maintenance practices and more efficient tracking;
- Partnered with community groups and non-profits to develop pollinator habitats and other solutions for protecting Ontario's biodiversity;
- Enhanced our Biodiversity GIS (geographic information system) Portal with new source water protection and invasive species layers;
- Developed a Biodiversity Program Framework, outlining the Company's plans for 2018 and beyond with regards to our Biodiversity Program; and
- Installed 12 new osprey nesting boxes for osprey habitats throughout the province.

Community Investment

At Hydro One, we believe in not only powering communities by delivering electricity, but also by investing dollars into the communities where our people and customers live and work.

In 2017, the Community Investment focus was on safety and injury prevention, Science, Technology, Engineering and Math (STEM) education and recreation projects for Indigenous communities. Contributions included a continuing partnership with the Ross Tilley Burn Centre at Sunnybrook Hospital to support the creation of a second burn unit operating room. We also supported the ACT Foundation by empowering Indigenous youth with life-saving skills through CPR and defibrillation training.

$1.1m (approx.)
Donations made to over 40 charitable partners and organizations

$1.3m
Donations made by employees and pensioners to impact local organizations in the communities where they live and work

$1.1m
Community sponsorships made to support local community events

YEAR IN REVIEW

Growth within North America

We announced our plan to acquire Avista to create a top 20 North American utility focused on regulated transmission as well as electricity and natural gas local distribution.

Billing

The Company's customer billing accuracy reached an all-time high of 99.3 per cent in 2017.

99.3% BILLING ACCURACY

Renewed Customer Experience

Hydro One introduced a new website in August, making it even easier for customers to do business with us. The website is mobile friendly and promotes more self-service options to meet our changing customer needs.

Launched a new, easy-to-read customer statement. Listening to our customer's feedback to make it simple and straightforward.

Customer Service

Customer satisfaction reached the highest it's been in four years for our distribution customers.

Revised customer-focused collection practices have resulted in a $40 million reduction in overdue accounts receivable.

Productivity Savings[1]

$89.5 million in savings in 2017 achieved through operational improvements.

Productivity Savings

Leadership

Hydro One was awarded the Progressive Aboriginal Relations Bronze Certification for demonstrating a commitment to Aboriginal communities.

Mayo Schmidt was awarded Ontario Energy Association's 2017 Leader of the Year award.

Strong North American Reputation

Hydro One demonstrated operational excellence as part of the unprecedented Hurricane Irma restoration efforts in Florida. Hydro One's efforts in Florida earned the Company an award from the Edison Electric Institute.

AWARD WINNING

Our System

Distribution
$689 million in distribution assets placed in-service.

Transmission
$889 million in transmission assets placed in-service.

$1,578 MILLION DISTRIBUTION & TRANSMISSION ASSETS PLACED IN-SERVICE

Core Values

At Hydro One, we are led by our purpose to make the impossible, possible for our customers as well as the communities we serve. Our core values guide how all employees behave, how we do our work and how we interact with one another.

Safety Comes First
Nothing is more important than the health and safety of our employees, our customers and the public. We make the world a safer place by setting a high bar that others aspire to.

Stand For People
We foster an open, collaborative work environment. We work to build relationships internally and externally based on trust and mutual respect. We believe in equality for all people and view diversity as a source of our strength.

Empowered to Act
We recognize our power to improve people's lives. We are ready to act in any situation. We capitalize of opportunities. We make the impossible, possible.

Optimism Charges Us
Optimism creates potential in everything we do. We think creatively and innovatively to turn challenges into opportunities.

Win as One
Winning is about doing well while also doing good. It means working together as one Company to deliver strong results for our customers, communities, employees and shareholders.

To learn more about our values, go to:
www.HydroOne.com/investor-relations

1. Productivity savings achieved are as a result of operational improvements in both capital and OM&A.

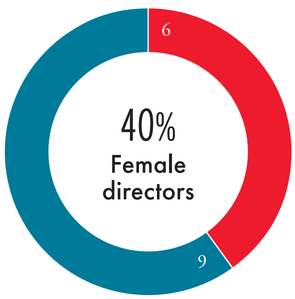
CORPORATE GOVERNANCE OVERVIEW

Board of Directors and Committees

	Audit Committee	Nominating, Corporate Governance Public Policy and Regulatory Committee	Human Resources Committee	Health, Safety, Environment and Indigenous Peoples Committee
David Denison *Chair*				
Mayo Schmidt *President and CEO*				
Ian Bourne		•	★	
Charles Brindamour	•		•	
Marc Caira		•	•	
Christie Clark		•	•	
George Cooke	•			•
Marianne Harris			•	★
Jim Hinds	•			•
Kathryn Jackson		•		•
Roberta Jamieson	•			•
Frances Lankin	•	•		
Philip Orsino	★	•		
Jane Peverett		★	•	
Gale Rubenstein			•	•

★ Chair • Committee Member

Board Diversity



• Female • Male

Strong corporate governance practices are the heart of how we manage our day-to-day operations in the interest of all stakeholders.

Hydro One and its independent Board of Directors recognize the importance of corporate governance in the effective management of the Company. Independence, integrity and accountability are the foundation of Hydro One's approach to corporate governance. It is in the long-term best interests of shareholders, and promotes and strengthens relationships with our customers, employees, the communities where we operate and other stakeholders of the Company. The Board of Directors is firmly supported in these commitments by a governance agreement between Hydro One and the province of Ontario, which was executed in advance of the November 2015 Initial Public Offering of the Company and assures that the province's role is limited to that of a shareholder and not a manager of the business.

Hydro One's Board of Directors is composed of a diverse and accomplished group of independent, proven business leaders with deep corporate governance experience. The Board's primary role is overseeing corporate performance and the quality, depth and continuity of management required to meet the Company's strategic objectives. Hydro One is committed to best practices of corporate governance, and regularly reviews the Company's governance practices in response to changing governance expectations and regulations. The Company's practices are fully aligned with the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

Board Structure

The Chair is responsible for leading the Board of Directors in carrying out its duties and responsibilities effectively, efficiently and independent of management. The Chair is nominated and confirmed annually by special resolution of the Board. Consistent with best practices, Hydro One's Board Chair is separate from the role of president and chief executive officer, and is independent of Hydro One and also of the province of Ontario.

To learn more about directors, committee mandates and composition, go to:
www.HydroOne.com/investor-relations

FINANCIAL REPORT

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MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2017 and 2016

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2017. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2017, based on information available to management as of February 12, 2018.

Consolidated Financial Highlights and Statistics

Year ended December 31

(millions of dollars, except as otherwise noted)	2017	2016	Change
Revenues	**5,990**	6,552	(8.6%)
Purchased power	**2,875**	3,427	(16.1%)
Revenues, net of purchased power[1]	**3,115**	3,125	(0.3%)
Operation, maintenance and administration costs	**1,066**	1,069	(0.3%)
Depreciation and amortization	**817**	778	5.0%
Financing charges	**439**	393	11.7%
Income tax expense	**111**	139	(20.1%)
Net income attributable to common shareholders of Hydro One	**658**	**721**	**(8.7%)**
Basic earnings per common share (EPS)	**$ 1.11**	$ 1.21	(8.3%)
Diluted EPS	**$ 1.10**	$ 1.21	(9.1%)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$ 1.17**	$ 1.21	(3.3%)
Diluted Adjusted EPS[1]	**$ 1.16**	$ 1.21	(4.1%)
Net cash from operating activities	**1,716**	1,656	3.6%
Funds from operations (FFO)[1]	**1,579**	1,494	5.7%
Capital investments	**1,567**	1,697	(7.7%)
Assets placed in-service	**1,592**	1,605	(0.8%)
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	**52.9%**	52.6%

1 See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

2 Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

Overview

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the year ended December 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	48%	1%

At December 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The transmission business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), as well as a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the OEB.

	2017	2016
Electricity transmitted[1] (MWh)	**132,090,992**	136,989,747
Transmission lines spanning the province (circuit-kilometres)	**30,290**	30,259
Rate base (millions of dollars)	**11,251**	10,775
Capital investments (millions of dollars)	**968**	988
Assets placed in-service (millions of dollars)	**889**	937

1 Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

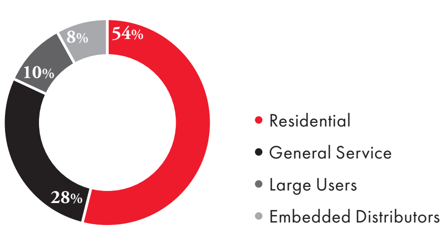
Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are approved by the OEB.

	2017	2016
Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289
Electricity distributed through Hydro One lines (GWh)[1]	**36,525**	37,394
Distribution lines spanning the province (circuit-kilometres)	**123,361**	122,599
Distribution customers (number of customers)	**1,372,362**	1,355,302
Rate base (millions of dollars)	**7,389**	7,056
Capital investments (millions of dollars)	**588**	703
Assets placed in-service (millions of dollars)	**689**	662

1 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

2017 Distribution Revenues



Other Business Segment

Hydro One's other business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's transmission and distribution businesses, and also offers communications and IT solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable broadband connectivity. Hydro One's other business segment is not rate-regulated.

Primary Factors Affecting Results of Operations

Transmission Revenues

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues include regulated distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation and amortization also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt and short-term borrowings, and gains and losses on interest rate swap agreements, contingent foreign exchange or other similar contracts, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

Results of Operations

Net Income

Net income attributable to common shareholders for the year ended December 31, 2017 of $658 million is a decrease of $63 million or 8.7% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017–2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;

- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, and a tax recovery of previous year's expenses; as well as reduced vegetation management costs and lower support services costs. These factors were offset by higher consulting costs primarily related to the acquisition of Avista Corporation; and lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system;
- increased financing charges primarily due to the issuance of convertible debentures in August 2017; as well as a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; and
- higher depreciation expense due to an increase in property, plant and equipment.

EPS and Adjusted EPS

EPS of $1.11 in 2017, compared to $1.21 in 2016. The decrease in EPS was driven by lower net income in 2017, as discussed above. Adjusted EPS, which adjusts for costs related to the Avista Corporation acquisition, was $1.17 in 2017, compared to $1.21 in 2016. The decrease in Adjusted EPS was also driven by lower net income in 2017, as discussed above, excluding the aforementioned impact related to Avista Corporation acquisition. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

Year ended December 31

(millions of dollars, except as otherwise noted)	2017	2016	Change
Transmission	**1,578**	1,584	(0.4%)
Distribution	**4,366**	4,915	(11.2%)
Other	**46**	53	(13.2%)
Total revenues	**5,990**	6,552	(8.6%)
Transmission	**1,578**	1,584	(0.4%)
Distribution, net of purchased power	**1,491**	1,488	0.2%
Other	**46**	53	(13.2%)
Total revenues, net of purchased power	**3,115**	3,125	(0.3%)
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017–2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31

(millions of dollars)	2017	2016	Change
Transmission	**375**	382	(1.8%)
Distribution	**593**	608	(2.5%)
Other	**98**	79	24.1%
	1,066	1,069	(0.3%)

Transmission OM&A Costs

The decrease of 1.8% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

Distribution OM&A Costs

The decrease of 2.5% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

Other OM&A Costs

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to the acquisition of Avista Corporation.

Depreciation and Amortization

The increase of $39 million or 5.0% in depreciation and amortization costs for 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The increase of $46 million or 11.7% in financing charges for the year ended December 31, 2017 was primarily due to the following:

- an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense related to the Convertible Debentures issued in August 2017.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $28 million compared to 2016, and the Company realized an effective tax rate of approximately 14.0% in 2017, compared to approximately 15.7% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 9, 2017	March 14, 2017	March 31, 2017	$ 0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$ 0.22	131
August 8, 2017	September 12, 2017	September 29, 2017	$ 0.22	131
November 9, 2017	December 12, 2017	December 29, 2017	$ 0.22	131
				518

Following the conclusion of the fourth quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 12, 2018	March 13, 2018	March 29, 2018	$ 0.22	131

Selected Annual Financial Statistics

Year ended December 31

(millions of dollars, except per share amounts)	**2017**	2016	2015
Revenues	**5,990**	6,552	6,538
Net income attributable to common shareholders	**658**	721	690
Basic EPS	**$ 1.11**	$ 1.21	$ 1.39
Diluted EPS	**$ 1.10**	$ 1.21	$ 1.39
Basic Adjusted EPS	**$ 1.17**	$ 1.21	$ 1.16
Diluted Adjusted EPS	**$ 1.16**	$ 1.21	$ 1.16
Dividends per common share declared	**$ 0.87**	$ 0.97[1]	$ 1.83
Dividends per preferred share declared	**$ 1.06**	$ 1.12	$ 1.03

1 The $0.97 per share dividends declared in 2016 included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

December 31

(millions of dollars)	**2017**	2016	2015
Total assets	**25,701**	25,351	24,294
Total non-current financial liabilities	**9,802**	10,078	8,207

Quarterly Results of Operations

Quarter ended

(millions of dollars, except EPS)	**Dec 31, 2017**	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	**1,439**	1,522	1,371	1,658	1,614	1,706	1,546	1,686
Purchased power	**662**	675	649	889	858	870	803	896
Revenues, net of purchased power	**777**	847	722	769	756	836	743	790
Net income to common shareholders	**155**	219	117	167	128	233	152	208
Basic EPS	**$ 0.26**	$ 0.37	$ 0.20	$ 0.28	$ 0.22	$ 0.39	$ 0.26	$ 0.35
Diluted EPS	**$ 0.26**	$ 0.37	$ 0.20	$ 0.28	$ 0.21	$ 0.39	$ 0.25	$ 0.35
Basic Adjusted EPS[1]	**$ 0.29**	$ 0.40	$ 0.20	$ 0.28	$ 0.22	$ 0.39	$ 0.26	$ 0.35
Diluted Adjusted EPS[1]	**$ 0.28**	$ 0.40	$ 0.20	$ 0.28	$ 0.21	$ 0.39	$ 0.25	$ 0.35

1 See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

Capital Investments

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016	Change
Transmission	**889**	937	(5.1%)
Distribution	**689**	662	4.1%
Other	**14**	6	133.3%
Total assets placed in-Service	**1,592**	1,605	(0.8%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016	Change
Transmission			
Sustaining	**764**	750	1.9%
Development	**137**	156	(12.2%)
Other	**67**	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	**280**	384	(27.1%)
Development	**227**	217	4.6%
Other	**81**	102	(20.6%)
	588	703	(16.4%)
Other	**11**	6	83.3%
Total capital investments	**1,567**	1,697	(7.7%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$ 57 million[1]	$ 52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Expansion Station	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$ 7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$ 1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$ 85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$ 93 million	$ 51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$ 95 million	$ 44 million

1 In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.
2 The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017–2018 transmission rates decision issued in September 2017. The projections and the timing of 2019–2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Other	9	8	6	9	8
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	217	272	184	177	179
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

1 "Other" capital expenditures consist of special projects, such as those relating to information technology.

Summary of Sources and Uses of Cash

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 (millions of dollars)	2017	2016
Cash provided by operating activities	**1,716**	1,656
Cash provided by (used in) financing activities	**(201)**	161
Cash used in investing activities	**(1,540)**	(1,861)
Decrease in cash and cash equivalents	**(25)**	(44)

Cash Provided by Operating Activities

Cash from Operating Activities increased by $60 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash Provided by Financing Activities

Sources of Cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- In 2017, the Company received proceeds of $513 million, representing the first instalment of the convertible debentures issued, gross of $27 million financing costs, compared to no convertible debentures issuances in 2016.

Uses of Cash

- Dividends paid in 2017 were $536 million, consisting of $518 million common share dividends and $18 million of preferred share dividends, compared to dividends of $596 million paid in 2016, consisting of $577 million common share dividends and $19 million of preferred share dividends. The 2016 common share dividends included $77 million of dividends for the post-IPO period from November 5 to December 31, 2015, and $500 million of dividends for the year ended December 31, 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash Used in Investing Activities

Uses of Cash

- Capital expenditures were $114 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

Liquidity and Financing Strategy

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2017, Hydro One Inc. had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province. See "Other Developments – Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures. The Convertible Debentures instalment receipts trade on the Toronto Stock Exchange under the ticker symbol "H.IR". The Convertible Debentures were sold as part of Hydro One's acquisition financing strategy to acquire Avista Corporation (see section Other Developments – Avista Corporation Purchase agreement), which includes the issuance of $1,540 million of Hydro One common shares and US$2.6 billion of Hydro One debt. The Convertible Debentures were sold to satisfy the equity component of the acquisition financing strategy.

To mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed by the issuance of Convertible Debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. The balance of the Avista Corporation acquisition will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge. At December 31, 2017, a fair value loss of $3 million was recorded with a corresponding derivative liability.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

1 On July 19, 2017, S&P revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

At December 31, 2017, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
S&P[1]	A-1	A

1 On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. See section "Risk Management and Risk Factors – Risks Relating to Hydro One's Business – Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits".

Other Obligations

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

December 31, 2017

(millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations (due by year)					
Long-term debt – principal repayments	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Convertible debentures – principal repayments[1]	513	—	—	—	513
Convertible debentures – interest payments	601	62	123	123	293
Short-term notes payable	926	926	—	—	—
Pension contributions[2]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	44	12	18	10	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	20,512	2,433	2,580	2,073	13,462
Other commercial commitments (by year of expiry)					
Credit facilities[3]	2,550	—	—	2,550	—
Letters of credit[4]	177	177	—	—	—
Guarantees[5]	325	325	—	—	—
Total other commercial commitments	3,052	502	—	2,550	—

1 The Company expects that the Convertible Debentures will be converted to common shares upon closing of the Avista Corporation acquisition.
2 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.
3 In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.
4 Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.
5 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Regulation

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2017–2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015–2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018–2022	Distribution – Custom	OEB decision pending
B2M LP	2015–2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017–2018	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending
Leave to Construct			
East-West Tie Station Expansion	n/a	Section 92	OEB decision pending

1 In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

1 On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks – Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018–2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks – Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018–2022 distribution rates under the OEB's incentive-based regulatory framework (2018–2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

On November 17, 2017, Hydro One filed with the OEB a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim rates based on current OEB-approved rates with no adjustments.

In Hydro One's December 21, 2017 update to the 2018–2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018–2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018–2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018–2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

Other Developments

Strategy
In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Common Shares
On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly held approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One, representing approximately 2.4% of the outstanding common shares, to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. After completing this transaction, the Province owns approximately 47.4% or 282.4 million common shares of Hydro One. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Collective Agreements
On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Exemptive Relief
On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

Avista Corporation Purchase Agreement
On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is expected to occur in the second half of 2018, subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. On November 21, 2017, the Merger was approved by the shareholders of Avista Corporation. On January 16, 2018, the Federal Energy Regulatory Commission approved the Merger application. Required filings with a number of other agencies will be made in the coming months, including with the Committee on Foreign Investment in the United States, the Federal Communications Commission, and the Department of Justice and the Federal Trade Commission pursuant to the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*.

Convertible Debenture Offering
On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company and its wholly-owned subsidiary, 2587264 Ontario Inc., completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures represented by instalment receipts (Debenture Offering). Upon closing of the Avista Corporation transaction and conversion of the Convertible Debentures into Hydro One common shares, the Province's ownership of Hydro One will decrease to approximately 42.3%. See section "Liquidity and Financing Strategy".

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Litigation

Litigation Relating to the Merger
To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

Class Action Lawsuit
Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

Hydro One Work Force

Hydro One has a skilled and flexible work force of approximately 5,400 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2017.

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,362	706	4,068
The Society	1,379	35	1,414
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,741	1,995	6,736
Management and non-represented employees	681	23	704
Total employees	5,422	2,018	7,440

1 Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.
2 The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-Based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 429,980 and 230,600 PSUs, respectively, and 393,430 and 254,150 RSUs, respectively, were outstanding.

Non-GAAP Measures

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 (millions of dollars)	2017	2016
Net cash from operating activities	**1,716**	1,656
Changes in non-cash balances related to operations	**(113)**	(134)
Preferred share dividends	**(18)**	(19)
Distributions to noncontrolling interest	**(6)**	(9)
FFO	**1,579**	1,494

Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs related to the Avista Corporation acquisition from net income. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and provides users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

Year ended December 31	2017	2016
Net income attributable to common shareholders (millions of dollars)	**658**	721
Costs related to acquisition of Avista Corporation (millions of dollars)	**36**	—
Adjusted net income attributable to common shareholders (millions of dollars)	**694**	721
Weighted average number of shares		
Basic	**595,287,586**	595,000,000
Effect of dilutive stock-based compensation plans	**2,234,665**	1,700,823
Diluted	**597,522,251**	596,700,823
Adjusted EPS		
Basic	**$ 1.17**	$ 1.21
Diluted	**$ 1.16**	$ 1.21

Revenues, Net of Purchased Power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

Year ended December 31 (millions of dollars)	2017	2016
Revenues	**5,990**	6,552
Less: Purchased power	**2,875**	3,427
Revenues, net of purchased power	**3,115**	3,125

Year ended December 31 (millions of dollars)	2017	2016
Distribution revenues	**4,366**	4,915
Less: Purchased power	**2,875**	3,427
Distribution revenues, net of purchased power	**1,491**	1,488

FFO, basic and diluted Adjusted EPS, and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

Related Party Transactions

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)

Related Party	Transaction	2017	2016
Province	Dividends paid	**301**	451
IESO	Power purchased	**1,583**	2,096
	Revenues for transmission services	**1,521**	1,549
	Amounts related to electricity rebates	**357**	—
	Distribution revenues related to rural rate protection	**247**	125
	Distribution revenues related to the supply of electricity to remote northern communities	**32**	32
	Funding received related to CDM programs	**59**	63
OPG	Power purchased	**9**	6
	Revenues related to provision of construction and equipment maintenance services	**3**	5
	Costs related to the purchase of services	**1**	1
OEFC	Power purchased from power contracts administered by the OEFC	**2**	1
OEB	OEB fees	**8**	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	**—**	3

Risk Management and Risk Factors

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications – Hydro One Networks – Transmission"), may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

After rates are set as part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Regulatory Treatment of Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications – Hydro One Networks – Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

Indigenous Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada)) (Reserve) lands, and lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights.

The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "- Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. The Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with the Society with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020.

Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Corporation to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company. This risk may be further exacerbated by the funding requirements for completing the Merger. See also "Risk Factors Relating to the Merger – Sources of funding that would be used to fund the Merger may not be available"

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk. The Company is exposed to foreign exchange risk in connection with the Merger. See "Risk Factors Relating to the Merger – Foreign exchange risk". In the future, the Company may be exposed to additional foreign exchange risk in connection with other acquisitions or transactions in which it completes in a currency other than Canadian dollars. Although the Company may attempt to mitigate such risk through hedging transactions, there can be no assurance any such hedge will fully mitigate the risk of currency exchange fluctuations.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However, the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure.

The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "– Other Post-Employment and Post-Retirement Benefits Risks".

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements
Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors
The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks
In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company. See also "Other Developments – Litigation – Class Action Lawsuit" and "– Risk Factors Relating to the Merger – Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger".

Transmission Assets on Third-Party Lands Risk
Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk
Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risks Associated with Acquisitions
While the Company has experience in operating in the Ontario electricity market, as it pursues acquisitions outside of Ontario it will need to develop additional expertise in these new markets. Such acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs. Realization of the anticipated benefits will depend, in part, on the Company's ability to successfully integrate the acquired business, including the requirement to devote management attention and resources to integrating business practices and support functions. The failure to realize the anticipated benefits, the diversion of management's attention, or any delays or difficulties encountered in connection with the integration could have an adverse effect on the Company's business, results of operations, financial condition or cash flows. See "Risk Factors Relating to the Merger" for the specific risks in respect of the Company's proposed acquisition of Avista Corporation.

Risk Factors Relating to the Merger

Hydro One May Fail to Complete the Merger
The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated or at all. The completion of the Merger is subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro

One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US$103 million.

Length of Time Required to Complete the Merger is Unknown
As described above under "Hydro One may fail to complete the Merger", the closing of the Merger is subject to the receipt of certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on Hydro One's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavourable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), Hydro One could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required regulatory approvals and satisfying the other required closing conditions.

Foreign Exchange Risk
The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger. This risk has been partially mitigated through entering into a foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars which is contingent upon the closing of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional Demands Will be Placed on Hydro One as a Result of the Merger
As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of Funding that Would be Used to Fund the Merger May not be Available
Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company. There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates or changes in tax rates that could affect the underlying after-tax cost of any financing may affect the expected accretion of the Merger.

Hydro One Expects to Incur Significant Merger-Related Expenses
Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approvals. Additional unanticipated costs may be incurred.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger
One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. The plaintiffs in the lawsuit are seeking to enjoin the Merger and may pursue other remedies, including monetary damages and attorneys' fees. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One, including by delaying or preventing the Merger from becoming effective. See also "Other Developments – Litigation – Litigation Relating to the Merger".

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will Substantially Increase its Amount of Indebtedness Following the Merger
After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US$1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a pro forma basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (*pro formas* assumed no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One's substantially increased amount of indebtedness following the Merger may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering Could Result in a Downgrade of Hydro One's Credit Ratings
The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering or otherwise could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with the Province

Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions
The Province currently owns approximately 47.4% of the outstanding common shares of Hydro One. The Electricity Act restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

The share ownership restrictions in the *Electricity Act* (Share Ownership Restrictions) and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair
Although director nominees (other than the Chief Executive Officer) are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board of Directors, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights
Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board of Directors, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation
Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company.

Prohibitions on Selling the Company's Transmission or Distribution Business
The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

Although the Province has indicated that it does not intend to sell further common shares of Hydro One, the registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

Critical Accounting Estimates and Judgments

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate
The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets
The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase
The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2017.

Salary Increase Assumptions
Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflect negotiated salary rate increases over the contract period.

Mortality Assumptions
The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

Rate of Increase in Health Care Cost Trends
The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

Valuation of Deferred Tax Assets
Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

Asset Impairment
Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2017, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting
Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction

of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

Internal control over financial reporting is a subset of the internal control framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2017.

Together, disclosure controls and procedures and internal control over financial reporting provide internal control over reporting and disclosure. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

New Accounting Pronouncements

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

Summary of Fourth Quarter Results of Operations

Three months ended December 31

(millions of dollars, except EPS)	2017	2016	Change
Revenues			
Distribution	**1,049**	1,228	(14.6%)
Transmission	**379**	373	1.6%
Other	**11**	13	(15.4%)
	1,439	1,614	(10.8%)
Costs			
Purchased power	**662**	858	(22.8%)
OM&A			
Distribution	**146**	163	(10.4%)
Transmission	**79**	98	(19.4%)
Other	**19**	26	(26.9%)
	244	287	(15.0%)
Depreciation and amortization	**214**	204	4.9%
	1,120	1,349	(17.0%)
Income before financing charges and income taxes	**319**	**265**	**20.4%**
Financing charges	**119**	101	17.8%
Income before income taxes	**200**	**164**	**22.0%**
Income taxes	**38**	29	31.0%
Net income	**162**	135	20.0%
Net income attributable to common shareholders of Hydro One	**155**	**128**	**21.1%**
Basic EPS	**$ 0.26**	$ 0.22	18.2%
Diluted EPS	**$ 0.26**	$ 0.21	23.8%
Basic Adjusted EPS	**$ 0.29**	$ 0.22	31.8%
Diluted Adjusted EPS	**$ 0.28**	$ 0.21	33.3%
Capital Investments			
Distribution	**161**	201	(19.9%)
Transmission	**267**	274	(2.6%)
Other	**3**	2	50.0%
	431	477	(9.6%)
Assets Placed In-Service			
Distribution	**207**	211	(1.9%)
Transmission	**522**	488	7.0%
Other	**4**	0	100.0%
	733	699	4.9%

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2017 of $155 million is an increase of $27 million or 21.1% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017–2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to the issuance of Convertible Debentures in August 2017.

EPS and Adjusted EPS

EPS was $0.26 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in EPS was driven by higher net income for the fourth quarter of 2017, as discussed above. Adjusted EPS, which adjusts for costs related to Avista Corporation acquisition, was $0.29 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in Adjusted EPS was also driven by higher net income for the fourth quarter of 2017, net of aforementioned impact related to Avista Corporation acquisition.

Revenues

The quarterly increase of $6 million or 1.6% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $19 million or 19.4% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations; lower support services costs; and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $17 million or 10.4% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $10 million or 4.9% in depreciation and amortization costs for the fourth quarter of 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The quarterly increase of $18 million or 17.8% in financing charges was primarily due to an increase in interest expense related to the Convertible Debentures issued in August 2017; partially offset by a decrease in interest expense on long-term debt resulting from a decrease in weighted average long-term debt outstanding during the quarter, together with a decrease in the weighted average interest rate.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $9 million compared to 2016, and the Company realized an effective tax rate of approximately 19.0% in the fourth quarter of 2017, compared to approximately 17.7% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

The decrease in transmission capital investments during the fourth quarter was primarily due to the following:

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by

- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

The decrease in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

Forward-Looking Statements and Information

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion; and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Convertible Debentures; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the appointment of Hydro One's new Chief Financial Officer; risk associated with acquisitions; cyber and data security; expectations related to work force demographics; the Company's financing strategy and foreign currency hedging relating to the acquisition of Avista Corporation; class action litigation, including litigation relating to the Merger; the risk that the Company may fail to complete the Merger; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; the Province's ownership of Hydro One; future sales of shares of Hydro One; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;

- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 12, 2018.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2017. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

On behalf of Hydro One's management:

Mayo Schmidt
President and Chief Executive Officer

Christopher Lopez
Senior Vice President, Finance acting in the capacity of Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Hydro One Limited

We have audited the accompanying consolidated financial statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2017 and December 31, 2016, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants,
Licensed Public Accountants

February 12, 2018
Toronto, Canada

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) (Note 27)	**4,366**	4,915
Transmission (includes $1,523 related party revenues; 2016 – $1,553) (Note 27)	**1,578**	1,584
Other	**46**	53
	5,990	6,552
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) (Note 27)	**2,875**	3,427
Operation, maintenance and administration (Note 27)	**1,066**	1,069
Depreciation and amortization (Note 5)	**817**	778
	4,758	5,274
Income before financing charges and income taxes	**1,232**	1,278
Financing charges (Note 6)	**439**	393
Income before income taxes	**793**	885
Income taxes (Note 7)	**111**	139
Net income	**682**	746
Other comprehensive income	**1**	—
Comprehensive income	**683**	746
Net income attributable to:		
Noncontrolling interest (Note 26)	**6**	6
Preferred shareholders	**18**	19
Common shareholders	**658**	721
	682	746
Comprehensive income attributable to:		
Noncontrolling interest (Note 26)	**6**	6
Preferred shareholders	**18**	19
Common shareholders	**659**	721
	683	746
Earnings per common share (Note 24)		
Basic	**$ 1.11**	$ 1.21
Diluted	**$ 1.10**	$ 1.21
Dividends per common share declared (Note 23)	**$ 0.87**	$ 0.97

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (millions of Canadian dollars)	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	**25**	50
Accounts receivable (Note 8)	**636**	838
Due from related parties (Note 27)	**253**	158
Other current assets (Note 9)	**105**	102
	1,019	1,148
Property, plant and equipment (Note 10)	**19,947**	19,140
Other long-term assets:		
Regulatory assets (Note 12)	**3,049**	3,145
Deferred income tax assets (Note 7)	**987**	1,235
Intangible assets (Note 11)	**369**	349
Goodwill (Note 4)	**325**	327
Other assets	**5**	7
	4,735	5,063
Total assets	**25,701**	25,351
Liabilities		
Current liabilities:		
Short-term notes payable (Note 15)	**926**	469
Long-term debt payable within one year (Notes 15, 17)	**752**	602
Accounts payable and other current liabilities (Note 13)	**905**	945
Due to related parties (Note 27)	**157**	147
	2,740	2,163
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) (Notes 15, 17)	**9,315**	10,078
Convertible debentures (Notes 16, 17)	**487**	—
Regulatory liabilities (Note 12)	**128**	209
Deferred income tax liabilities (Note 7)	**71**	60
Other long-term liabilities (Note 14)	**2,707**	2,752
	12,708	13,099
Total liabilities	**15,448**	15,262
Contingencies and Commitments (Notes 29, 30)		
Subsequent Events (Note 32)		
Noncontrolling interest subject to redemption (Note 26)	**22**	22
Equity		
Common shares (Note 22)	**5,631**	5,623
Preferred shares (Note 22)	**418**	418
Additional paid-in capital (Note 25)	**49**	34
Retained earnings	**4,090**	3,950
Accumulated other comprehensive loss	**(7)**	(8)
Hydro One shareholders' equity	**10,181**	10,017
Noncontrolling interest (Note 26)	**50**	50
Total equity	**10,231**	10,067
	25,701	25,351

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31, 2017

(millions of Canadian dollars)	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non-controlling Interest (Note 26)	Total Equity
January 1, 2017	**5,623**	**418**	**34**	**3,950**	**(8)**	**10,017**	**50**	**10,067**
Net income	—	—	—	**676**	—	**676**	**4**	**680**
Other comprehensive income	—	—	—	—	**1**	**1**	—	**1**
Distributions to noncontrolling interest	—	—	—	—	—	—	**(4)**	**(4)**
Dividends on preferred shares	—	—	—	**(18)**	—	**(18)**	—	**(18)**
Dividends on common shares	—	—	—	**(518)**	—	**(518)**	—	**(518)**
Common shares issued	**8**	—	**(8)**	—	—	—	—	—
Stock-based compensation (Note 25)	—	—	**23**	—	—	**23**	—	**23**
December 31, 2017	**5,631**	**418**	**49**	**4,090**	**(7)**	**10,181**	**50**	**10,231**

Year ended December 31, 2016

(millions of Canadian dollars)	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest (Note 26)	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	740	—	740	4	744
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(6)	(6)
Dividends on preferred shares	—	—	—	(19)	—	(19)	—	(19)
Dividends on common shares	—	—	—	(577)	—	(577)	—	(577)
Stock-based compensation (Note 25)	—	—	24	—	—	24	—	24
December 31, 2016	5,623	418	34	3,950	(8)	10,017	50	10,067

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31		
(millions of Canadian dollars)	2017	2016
Operating activities		
Net income	**682**	746
Environmental expenditures	**(24)**	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	**727**	688
Regulatory assets and liabilities	**112**	(16)
Deferred income taxes	**85**	114
Other	**21**	10
Changes in non-cash balances related to operations (Note 28)	**113**	134
Net cash from operating activities	**1,716**	1,656
Financing activities		
Long-term debt issued	**—**	2,300
Long-term debt repaid	**(602)**	(502)
Short-term notes issued	**3,795**	3,031
Short-term notes repaid	**(3,338)**	(4,053)
Convertible debentures issued (Note 16)	**513**	—
Dividends paid	**(536)**	(596)
Distributions paid to noncontrolling interest	**(6)**	(9)
Other (Note 16)	**(27)**	(10)
Net cash from (used in) financing activities	**(201)**	161
Investing activities		
Capital expenditures (Note 28)		
Property, plant and equipment	**(1,467)**	(1,600)
Intangible assets	**(80)**	(61)
Acquisitions (Note 4)	**—**	(224)
Capital contributions received (Note 28)	**9**	21
Other	**(2)**	3
Net cash used in investing activities	**(1,540)**	(1,861)
Net change in cash and cash equivalents	**(25)**	(44)
Cash and cash equivalents, beginning of year	**50**	94
Cash and cash equivalents, end of year	**25**	50

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. Description of the Business

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2017, the Province held approximately 47.4% (2016 – 70.1%) of the common shares of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. Significant Accounting Policies

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and its 66% interest in B2M Limited Partnership (B2M LP).

The Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

Transmission

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. See Note 12 – Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Distribution

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Noncontrolling Interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	55 years	1% – 3%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	20 years	1% – 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2017 and 2016, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2017 or 2016.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Defined Benefit Pension

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

Post-Retirement and Post-Employment Benefits
Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

Share Grant Plans
Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans
The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Long-Term Incentive Plan (LTIP)
The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under its LTIP, at fair value based on the grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. New Accounting Pronouncements

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. Business Combinations

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions. See Note 16 – Convertible Debentures and Note 17 – Fair Value of Financial Instruments and Risk Management for details of convertible debentures and foreign exchange contract, respectively, related to financing of the Merger.

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

5. Depreciation and Amortization

Year ended December 31

(millions of dollars)	2017	2016
Depreciation of property, plant and equipment	**641**	612
Asset removal costs	**90**	90
Amortization of intangible assets	**62**	56
Amortization of regulatory assets	**24**	20
	817	778

6. Financing Charges

Year ended December 31

(millions of dollars)	2017	2016
Interest on long-term debt	**450**	424
Interest on convertible debentures	**24**	—
Interest on short-term notes	**6**	9
Unrealized loss on foreign exchange contract	**3**	—
Other	**14**	16
Less: Interest capitalized on construction and development in progress	**(56)**	(54)
Interest earned on cash and cash equivalents	**(2)**	(2)
	439	393

7. Income Taxes

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31

(millions of dollars)	2017	2016
Income before income taxes	**793**	885
Income taxes at statutory rate of 26.5% (2016 – 26.5%)	**210**	235
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	**(55)**	(53)
Pension contributions in excess of pension expense	**(13)**	(16)
Overheads capitalized for accounting but deducted for tax purposes	**(17)**	(16)
Interest capitalized for accounting but deducted for tax purposes	**(15)**	(14)
Environmental expenditures	**(6)**	(5)
Other	**3**	5
Net temporary differences	**(103)**	(99)
Net permanent differences	**4**	3
Total income taxes	**111**	139

The major components of income tax expense are as follows:

Year ended December 31

(millions of dollars)	2017	2016
Current income taxes	**26**	25
Deferred income taxes	**85**	114
Total income taxes	**111**	139
Effective income tax rate	**14.0%**	15.7%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	**125**	495
Non-depreciable capital property	**271**	271
Post-retirement and post-employment benefits expense in excess of cash payments	**561**	607
Environmental expenditures	**71**	74
Non-capital losses and tax credit carryforward	**255**	213
Tax credit carryforwards	**49**	27
Investment in subsidiaries	**84**	75
Other	**13**	3
	1,429	1,765
Less: valuation allowance	**(364)**	(352)
Total deferred income tax assets	**1,065**	1,413
Less: current portion	**—**	—
	1,065	1,413
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	**(47)**	(153)
Goodwill	**(10)**	(10)
Capital cost allowance in excess of depreciation and amortization	**(75)**	(64)
Other	**(17)**	(11)
Total deferred income tax liabilities	**(149)**	(238)
Less: current portion	**—**	—
	(149)	(238)
Net deferred income tax assets	**916**	1,175

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 (millions of dollars)	2017	2016
Long-term:		
Deferred income tax assets	**987**	1,235
Deferred income tax liabilities	**(71)**	(60)
Net deferred income tax assets	**916**	1,175

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 – $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry (millions of dollars)	2017	2016
2034	**2**	2
2035	**222**	222
2036	**560**	580
2037	**175**	—
Total losses	**959**	804

8. Accounts Receivable

December 31

(millions of dollars)	2017	2016
Accounts receivable – billed	**298**	431
Accounts receivable – unbilled	**367**	442
Accounts receivable, gross	**665**	873
Allowance for doubtful accounts	**(29)**	(35)
Accounts receivable, net	**636**	838

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31

(millions of dollars)	2017	2016
Allowance for doubtful accounts – beginning	**(35)**	(61)
Write-offs	**25**	37
Additions to allowance for doubtful accounts	**(19)**	(11)
Allowance for doubtful accounts – ending	**(29)**	(35)

9. Other Current Assets

December 31

(millions of dollars)	2017	2016
Regulatory assets (Note 12)	**46**	37
Materials and supplies	**18**	19
Prepaid expenses and other assets	**41**	46
	105	102

10. Property, Plant and Equipment

December 31, 2017

(millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	**15,509**	**5,162**	**989**	**11,336**
Distribution	**10,213**	**3,513**	**149**	**6,849**
Communication	**1,266**	**853**	**31**	**444**
Administration and service	**1,561**	**857**	**46**	**750**
Easements	**638**	**70**	**—**	**568**
	29,187	**10,455**	**1,215**	**19,947**

December 31, 2016

(millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,233	777	20	476
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,841	9,935	1,234	19,140

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 – $52 million).

11. Intangible Assets

December 31, 2017

(millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	**698**	**370**	**41**	**369**
Other	**5**	**5**	**—**	**—**
	703	**375**	**41**	**369**

December 31, 2016

(millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 – $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 – $67 million; 2019 – $57 million; 2020 – $40 million; 2021 – $39 million; and 2022 – $36 million.

12. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31

(millions of dollars)	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	**1,762**	1,587
Pension benefit regulatory asset	**981**	900
Post-retirement and post-employment benefits	**36**	243
Environmental	**196**	204
Share-based compensation	**40**	31
Debt premium	**27**	32
Foregone revenue deferral	**23**	—
Distribution system code exemption	**10**	10
B2M LP start-up costs	**4**	5
Retail settlement variance account	**—**	145
2015–2017 rate rider	**—**	7
Pension cost variance	**—**	4
Other	**16**	14
Total regulatory assets	**3,095**	3,182
Less: current portion	**(46)**	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	**60**	69
External revenue variance	**46**	64
CDM deferral variance	**28**	54
Pension cost variance	**23**	—
2015–2017 rate rider	**6**	—
Deferred income tax regulatory liability	**5**	4
Other	**17**	18
Total regulatory liabilities	**185**	209
Less: current portion	**(57)**	—
	128	209

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2017 income tax expense would have been higher by approximately $113 million (2016 – $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 – OCI higher by $52 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2017 OCI would have been higher by $207 million (2016 – lower by $3 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2017, the environmental regulatory asset increased by $1 million (2016 – decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 – $10 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 – $20 million), and 2017 financing charges would have been higher by $8 million (2016 – $8 million).

Share-Based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP – Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015–2017 Rate Rider.

2015–2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015–2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the deficit of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which was recovered through the 2015–2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 – $25 million).

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. Accounts Payable and Other Current Liabilities

December 31

(millions of dollars)	2017	2016
Accounts payable	**177**	181
Accrued liabilities	**572**	659
Accrued interest	**99**	105
Regulatory liabilities (Note 12)	**57**	—
	905	945

14. Other Long-Term Liabilities

December 31

(millions of dollars)	2017	2016
Post-retirement and post-employment benefit liability (Note 19)	**1,519**	1,641
Pension benefit liability (Note 19)	**981**	900
Environmental liabilities (Note 20)	**168**	177
Asset retirement obligations (Note 21)	**9**	9
Long-term accounts payable and other liabilities	**30**	25
	2,707	2,752

15. Debt and Credit Agreements

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At December 31, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

(millions of dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2022[1]	2,300
Hydro One		
Five-year senior, revolving term credit facility	November 2021	250
Total		2,550

1 In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2017 and 2016:

December 31 (millions of dollars)	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	**750**	750
Floating-rate Series 31 notes due 2019[1]	**228**	228
1.48% Series 37 notes due 2019[2]	**500**	500
4.40% Series 20 notes due 2020	**300**	300
1.62% Series 33 notes due 2020[2]	**350**	350
1.84% Series 34 notes due 2021	**500**	500
3.20% Series 25 notes due 2022	**600**	600
2.77% Series 35 notes due 2026	**500**	500
7.35% Debentures due 2030	**400**	400
6.93% Series 2 notes due 2032	**500**	500
6.35% Series 4 notes due 2034	**385**	385
5.36% Series 9 notes due 2036	**600**	600
4.89% Series 12 notes due 2037	**400**	400
6.03% Series 17 notes due 2039	**300**	300
5.49% Series 18 notes due 2040	**500**	500
4.39% Series 23 notes due 2041	**300**	300
6.59% Series 5 notes due 2043	**315**	315
4.59% Series 29 notes due 2043	**435**	435
4.17% Series 32 notes due 2044	**350**	350
5.00% Series 11 notes due 2046	**325**	325
3.91% Series 36 notes due 2046	**350**	350
3.72% Series 38 notes due 2047	**450**	450
4.00% Series 24 notes due 2051	**225**	225
3.79% Series 26 notes due 2062	**310**	310
4.29% Series 30 notes due 2064	**50**	50
Hydro One Inc. long-term debt (a)	**9,923**	10,523
6.6% Senior Secured Bonds due 2023 (Face value – $110 million)	**136**	144
4.6% Note Payable due 2023 (Face value – $36 million)	**40**	40
HOSSM long-term debt (b)	**176**	184
	10,099	10,707
Add: Net unamortized debt premiums	**14**	15
Add: Unrealized mark-to-market gain[2]	**(9)**	(2)
Less: Deferred debt issuance costs	**(37)**	(40)
Total long-term debt	**10,067**	10,680

1 The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

2 The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. Long-Term Debt

At December 31, 2017, long-term debt of $9,923 million (2016 – $10,523 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 – $2,300 million issued and $500 million repaid).

(b) HOSSM Long-Term Debt

At December 31, 2017, long-term debt of $176 million (2016 – $184 million), with a face value of $146 million (2016 – $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 – $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 (millions of dollars)	2017	2016
Current liabilities:		
Long-term debt payable within one year	**752**	602
Long-term liabilities:		
Long-term debt	**9,315**	10,078
Total long-term debt	**10,067**	10,680

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments (millions of dollars)	Weighted Average Interest Rate (%)
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments (millions of dollars)
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023–2027	1,672
2028+	4,081
	7,690

16. Convertible Debentures

(millions of dollars, except as otherwise noted)	
Maturity date	September 30, 2027
Coupon rate	4.00%
Conversion price per common share	$ 21.40
Carrying value at December 31, 2016	—
Receipt of Initial Instalment, net of deferred financing costs	486
Amortization of deferred financing costs	1
Carrying value at December 31, 2017	487
Face value at December 31, 2017	513

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) is payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred financing costs of $27 million, which are being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures will mature on September 30, 2027. A coupon rate of 4% is paid on the $1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translates into an effective annual yield of 12%. After the Final Instalment Date, the interest rate will be 0%. The interest expense recorded in 2017 is $24 million.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of the Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date (Make-Whole Payment). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

At the option of the holders and provided that payment of the Final Instalment has been made, each Convertible Debenture will be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures. The conversion feature meets the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized. Between the time the contingency is resolved and the Final Instalment Date, the Company will recognize approximately $92 million of interest expense associated with amortization of the BCF.

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that the Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Avista Corporation will not be satisfied; (ii) termination of the acquisition agreement; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders on or before April 30, 2019. Upon any such redemption, the Company will pay for each Convertible Debenture (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the selling debentureholder on behalf of the holder of the instalment receipt in satisfaction of the final instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in common shares, which will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

17. Fair Value of Financial Instruments and Risk Management

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2017 and 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2017 and 2016 are as follows:

December 31

(millions of dollars)	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
\$50 million of MTN Series 33 notes	**49**	**49**	50	50
\$500 million MTN Series 37 notes	**492**	**492**	498	498
Other notes and debentures	**9,526**	**11,027**	10,132	11,462
Long-term debt, including current portion	**10,067**	**11,568**	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One Inc. had interest-rate swaps in the amount of \$550 million (2016 – \$550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a \$50 million fixed-to-floating interest-rate swap agreement to convert \$50 million of the \$350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two \$125 million and one \$250 million fixed-to-floating interest-rate swap agreements to convert the \$500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert \$1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition (see Note 4 – Business Combinations) and is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 – Convertible Debentures). If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. This contract is an economic hedge and does not qualify for hedge accounting. It has been accounted for as an undesignated contract.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017

(millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	**25**	**25**	**25**	—	—
	25	**25**	**25**	—	—
Liabilities:					
Short-term notes payable	**926**	**926**	**926**	—	—
Long-term debt, including current portion	**10,067**	**11,568**	—	**11,568**	—
Convertible debentures	**487**	**574**	**574**	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	**9**	**9**	**9**	—	—
Foreign exchange contract	**3**	**3**	—	—	**3**
	11,492	**13,080**	**1,509**	**11,568**	**3**

December 31, 2016

(millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on December 29, 2017 (last business day in December 2017), as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves,probability of closing the Avista Corporation acquisition, and the contract settlement of date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probability of closing the Avista Corporation acquisition and the contract settlement date.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016.

Year ended December 31

(millions of dollars)	**2017**	2016
Fair value, beginning of year	—	—
Unrealized loss on foreign exchange contract included in financing charges (Note 6)	**3**	—
Fair value, end of year	**3**	—

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2017 and 2016.

The Company is exposed to foreign exchange fluctuations as a result of entering into a deal-contingent foreign exchange forward agreement (see section Fair Value Measurements of Derivative Instruments above). This agreement is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 – Convertible Debentures).

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

18. Capital Management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 (millions of dollars)	2017	2016
Long-term debt payable within one year	**752**	602
Short-term notes payable	**926**	469
Less: cash and cash equivalents	**(25)**	(50)
	1,653	1,021
Long-term debt	**9,315**	10,078
Convertible debentures	**487**	—
Preferred shares	**418**	418
Common shares	**5,631**	5,623
Retained earnings	**4,090**	3,950
Total capital	**21,594**	21,090

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. Hydro One Inc.'s long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

19. Pension and Post-Retirement and Post-Employment Benefits

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 – less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 – less than $1 million).

Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 – $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 – based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

Year ended December 31

(millions of dollars)	Pension Benefits 2017	2016	Post-Retirement and Post-Employment Benefits 2017	2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**7,774**	7,683	**1,690**	1,610
Current service cost	**147**	144	**49**	42
Employee contributions	**49**	45	**67**	—
Interest cost	**304**	308	—	67
Benefits paid	**(368)**	(354)	**(44)**	(43)
Net actuarial loss (gain)	**352**	(52)	**(197)**	14
Projected benefit obligation, end of year	**8,258**	7,774	**1,565**	1,690
Change in plan assets				
Fair value of plan assets, beginning of year	**6,874**	6,731	—	—
Actual return on plan assets	**662**	370	—	—
Benefits paid	**(368)**	(354)	**(34)**	(43)
Employer contributions	**87**	108	**34**	43
Employee contributions	**49**	45	—	—
Administrative expenses	**(27)**	(26)	—	—
Fair value of plan assets, end of year	**7,277**	6,874	—	—
Unfunded status	**981**	900	**1,565**	1,690

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31

(millions of dollars)	Pension Benefits 2017	2016	Post-Retirement and Post-Employment Benefits 2017	2016
Other assets[1]	**1**	1	—	—
Accrued liabilities	—	—	**53**	56
Pension benefit liability	**981**	900	—	—
Post-retirement and post-employment benefit liability[2]	—	—	**1,519**	1,641
Net unfunded status	**980**	899	**1,572**	1,697

1 Represents the funded status of HOSSM defined benefit pension plan.
2 Includes $7 million (2016 – $7 million) relating to HOSSM post-employment benefit plans.

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31

(millions of dollars)	2017	2016
PBO	**8,258**	7,774
ABO	**7,614**	7,094
Fair value of plan assets	**7,277**	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 – 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 – 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the Pension Plan:

Year ended December 31 (millions of dollars)	2017	2016
Current service cost	**147**	144
Interest cost	**304**	308
Expected return on plan assets, net of expenses	**(442)**	(432)
Amortization of actuarial losses	**79**	96
Net periodic benefit costs	**88**	116
Charged to results of operations[1]	**39**	48

1 The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $87 million (2016 – $108 million) were attributed to labour, of which $39 million (2016 – $48 million) was charged to operations, and $48 million (2016 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of dollars)	2017	2016
Current service cost	**49**	42
Interest cost	**67**	67
Amortization of actuarial losses	**16**	15
Net periodic benefit costs	**132**	124
Charged to results of operations	**59**	55

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	**3.40%**	3.90%	**3.40%**	3.90%
Rate of compensation scale escalation (long-term)	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trends[1]	**—**	—	**4.04%**	4.36%

1 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 – 6.25% in 2017, grading down to 4.36% per annum in and after 2031).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2017 and 2016. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.50%**	6.50%
Weighted average discount rate	**3.90%**	4.00%
Rate of compensation scale escalation (long-term)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees (years)	**15**	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	**3.90%**	4.10%
Rate of compensation scale escalation (long-term)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees (years)	**15.2**	15.3
Rate of increase in health care cost trends[1]	**4.36%**	4.36%

1 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 – 6.38% in 2016, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2017 and 2016 is as follows:

December 31 (millions of dollars)	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**250**	289
Effect of a 1% decrease in health care cost trends	**(189)**	(221)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2017 and 2016 is as follows:

Year ended December 31 (millions of dollars)	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**29**	23
Effect of a 1% decrease in health care cost trends	**(20)**	(17)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2017 and 2016:

December 31, 2017 Life expectancy at 65 for a member currently at				December 31, 2016 Life expectancy at 65 for a member currently at			
Age 65		Age 45		Age 65		Age 45	
Male	**Female**	**Male**	**Female**	Male	Female	Male	Female
22	**24**	**23**	**24**	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,866	312
Total estimated future benefit payments through to 2027	3,597	590

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of dollars)	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	**159**	35
Amortization of actuarial losses	**(79)**	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	**(197)**	14
Amortization of actuarial losses	**(16)**	(15)
Amounts not subject to regulatory treatment	**6**	4
	(207)	(3)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016
Pension Benefits:		
Actuarial loss	**981**	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	**36**	243

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of dollars)	**2017**	2016	**2017**	2016
Actuarial loss	**84**	79	**2**	6

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

1 Other investments include real estate and infrastructure investments.

At December 31, 2017, the Pension Plan held $11 million (2016 – $11 million) Hydro One corporate bonds and $415 million (2016 – $450 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2017 and 2016. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2017 and 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions, and also by ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016:

December 31, 2017

(millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	**16**	**549**	**565**
Cash and cash equivalents	**153**	—	—	**153**
Short-term securities	—	**109**	—	**109**
Derivative instruments	—	**5**	—	**5**
Corporate shares – Canadian	**921**	—	—	**921**
Corporate shares – Foreign	**3,307**	**125**	—	**3,432**
Bonds and debentures – Canadian	—	**1,879**	—	**1,879**
Bonds and debentures – Foreign	—	**194**	—	**194**
Total fair value of plan assets[1]	**4,381**	**2,328**	**549**	**7,258**

1 At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable and $1 million of purchased investments payable.

December 31, 2016 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares – Canadian	911	—	—	911
Corporate shares – Foreign	2,985	113	—	3,098
Bonds and debentures – Canadian	—	1,943	—	1,943
Bonds and debentures – Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

1 At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 17 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3
The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016.

The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of dollars)	2017	2016
Fair value, beginning of year	**425**	301
Realized and unrealized gains	**(31)**	23
Purchases	**171**	151
Sales and disbursements	**(16)**	(50)
Fair value, end of year	**549**	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value
Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

20. Environmental Liabilities

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Environmental liabilities – beginning	**143**	**61**	**204**
Interest accretion	**6**	**2**	**8**
Expenditures	**(16)**	**(8)**	**(24)**
Revaluation adjustment	**1**	**7**	**8**
Environmental liabilities – ending	**134**	**62**	**196**
Less: current portion	**(20)**	**(8)**	**(28)**
	114	**54**	**168**

Year ended December 31, 2016

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Environmental liabilities – beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities – ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2017

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	**142**	**64**	**206**
Less: discounting environmental liabilities to present value	**(8)**	**(2)**	**(10)**
Discounted environmental liabilities	**134**	**62**	**196**

Year ended December 31, 2016

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $142 million (2016 – $158 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 – reduce by $1 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $64 million (2016 – $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 – $10 million).

21. Asset Retirement Obligations

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 – $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

22. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 595,386,711 (2016 – 595,000,000) common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

The following tables present the changes to common shares during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017

(number of shares)	Ownership by Public	Ownership by Province	Total
Common shares – beginning	**178,196,340**	**416,803,660**	**595,000,000**
Secondary offering[1]	**120,000,000**	**(120,000,000)**	**—**
Common shares issued – share grants[2]	**371,611**	**—**	**371,611**
Common shares issued – LTIP[3]	**15,100**	**—**	**15,100**
Sale of common shares[4]	**14,391,012**	**(14,391,012)**	**—**
Common shares – ending	**312,974,063**	**282,412,648**	**595,386,711**
	52.6%	**47.4%**	**100%**

1 On May 17, 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.
2 On April 1, 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the Power Workers' Union (PWU) Share Grant Plan.
3 In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.
4 On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Year ended December 31, 2016

(number of shares)	Ownership by Public	Ownership by Province	Total
Common shares – beginning	94,896,340	500,103,660	595,000,000
Secondary offering[1]	83,300,000	(83,300,000)	—
Common shares – ending	178,196,340	416,803,660	595,000,000
	29.9%	70.1%	100%

1 On April 14, 2016, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 72,434,800 common shares of Hydro One on the Toronto Stock Exchange. In addition, the Province granted the underwriters an over-allotment option to purchase up to an additional 10,865,200 common shares of Hydro One which was fully exercised and closed on April 29, 2016. Hydro One did not receive any of the proceeds from the sale of common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2017 and 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2017 and 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2017, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

23. Dividends

In 2017, preferred share dividends in the amount of $18 million (2016 – $19 million) and common share dividends in the amount of $518 million (2016 – $577 million) were declared. The 2016 common share dividends include $77 million for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

24. Earnings Per Common Share

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the LTIP, which are calculated using the treasury stock method.

Year ended December 31	2017	2016
Net income attributable to common shareholders (millions of dollars)	**658**	721
Weighted average number of shares		
Basic	**595,287,586**	595,000,000
Effect of dilutive stock-based compensation plans	**2,234,665**	1,700,823
Diluted	**597,522,251**	596,700,823
EPS		
Basic	**$ 1.11**	$ 1.21
Diluted	**$ 1.10**	$ 1.21

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS until conditions for closing the Avista Corporation acquisition are met.

25. Stock-Based Compensation

Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2017, 371,611 common shares were granted under the Share Grant Plans (2016 – nil). Total share based compensation recognized during 2017 was $17 million (2016 – $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	**5,334,415**	**$ 20.50**
Vested and issued[1]	**(371,611)**	**—**
Forfeited	**(137,072)**	**$ 20.50**
Share grants outstanding – ending	**4,825,732**	**$ 20.50**

1 On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	5,412,354	$ 20.50
Forfeited	(77,939)	$ 20.50
Share grants outstanding – ending	5,334,415	$ 20.50

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 (number of DSUs)	2017	2016
DSUs outstanding – beginning	**99,083**	20,525
DSUs granted	**88,007**	78,558
DSUs outstanding – ending	**187,090**	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 – $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 – $2 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 (number of DSUs)	2017	2016
DSUs outstanding – beginning	**—**	—
Granted	**68,897**	—
Paid	**(1,068)**	—
DSUs outstanding – ending	**67,829**	—

For the year ended December 31, 2017, an expense of $2 million (2016 – $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 – $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 – $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for verall business performance.

During 2017 and 2016, the Company granted awards under its LTIP as follows:

Year ended December 31	PSUs		RSUs	
(number of units)	2017	2016	2017	2016
Units outstanding – beginning	**230,600**	—	**254,150**	—
Units granted	**303,240**	235,420	**242,860**	258,970
Units vested	**(609)**	—	**(14,079)**	—
Units forfeited	**(103,251)**	(4,820)	**(89,501)**	(4,820)
Units outstanding – ending	**429,980**	230,600	**393,430**	254,150

The grant date total fair value of the awards granted in 2017 was $13 million (2016 – $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 – $3 million).

26. Noncontrolling Interest

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017

(millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	**22**	**50**	**72**
Distributions to noncontrolling interest	**(2)**	**(4)**	**(6)**
Net income attributable to noncontrolling interest	**2**	**4**	**6**
Noncontrolling interest – ending	**22**	**50**	**72**

Year ended December 31, 2016

(millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

27. Related Party Transactions

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31

(millions of dollars) Related Party	Transaction	2017	2016
Province	Dividends paid	**301**	451
IESO	Power purchased	**1,583**	2,096
	Revenues for transmission services	**1,521**	1,549
	Amounts related to electricity rebates	**357**	—
	Distribution revenues related to rural rate protection	**247**	125
	Distribution revenues related to the supply of electricity to remote northern communities	**32**	32
	Funding received related to CDM programs	**59**	63
OPG	Power purchased	**9**	6
	Revenues related to provision of construction and equipment maintenance services	**3**	5
	Costs expensed related to the purchase of services	**1**	1
OEFC	Power purchased from power contracts administered by the OEFC	**2**	1
OEB	OEB fees	**8**	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

28. Consolidated Statements of Cash Flows

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2017	2016
Accounts receivable	**195**	(60)
Due from related parties	**(95)**	33
Materials and supplies	**1**	2
Prepaid expenses and other assets	**7**	(15)
Accounts payable	**7**	19
Accrued liabilities	**(89)**	53
Due to related parties	**10**	9
Accrued interest	**(6)**	9
Long-term accounts payable and other liabilities	**(2)**	6
Post-retirement and post-employment benefit liability	**85**	78
	113	134

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of dollars)	2017	2016
Capital investments in property, plant and equipment	**(1,493)**	(1,630)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	**26**	30
Cash outflow for capital expenditures – property, plant and equipment	**(1,467)**	(1,600)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 (millions of dollars)	2017	2016
Capital investments in intangible assets	**(74)**	(67)
Net change in accruals included in capital investments in intangible assets	**(6)**	6
Cash outflow for capital expenditures – intangible assets	**(80)**	(61)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2017, capital contributions from these reassessments totalled $9 million (2016 – $21 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 (millions of dollars)	2017	2016
Net interest paid	**475**	418
Income taxes paid	**12**	32

29. Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One Limited, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One Limited publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One Limited, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2017, the Company paid approximately $2 million (2016 – $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

30. Commitments

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

December 31, 2017

(millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	**139**	**95**	**2**	**2**	**2**	**7**
Long-term software/meter agreement	**17**	**17**	**16**	**2**	**1**	**3**
Operating lease commitments	**12**	**7**	**11**	**6**	**4**	**4**

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024.

Long-Term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2017, the Company made lease payments totalling $12 million (2016 – $11 million).

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter:

December 31, 2017

(millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	**250**	**2,300**	—
Letters of credit[1]	**177**	—	—	—	—	—
Guarantees[2]	**325**	—	—	—	—	—

1 Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

2 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

31. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2017

(millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	**1,578**	**4,366**	**46**	**5,990**
Purchased power	—	**2,875**	—	**2,875**
Operation, maintenance and administration	**375**	**593**	**98**	**1,066**
Depreciation and amortization	**420**	**390**	**7**	**817**
Income (loss) before financing charges and income taxes	**783**	**508**	**(59)**	**1,232**
Capital investments	**968**	**588**	**11**	**1,567**

Year ended December 31, 2016

(millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	1,584	4,915	53	6,552
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	382	608	79	1,069
Depreciation and amortization	390	379	9	778
Income (loss) before financing charges and income taxes	812	501	(35)	1,278
Capital investments	988	703	6	1,697

Total Assets by Segment:

December 31

(millions of dollars)	2017	2016
Transmission	**13,608**	13,071
Distribution	**9,259**	9,379
Other	**2,834**	2,901
Total assets	**25,701**	25,351

Total Goodwill by Segment:

December 31

(millions of dollars)	2017	2016
Transmission (Note 4)	**157**	159
Distribution	**168**	168
Total goodwill	**325**	327

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

32. Subsequent Events

Dividends

On February 12, 2018, preferred share dividends in the amount of $4 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

BOARD OF DIRECTORS & SENIOR LEADERSHIP TEAM

Board of Directors

Senior Leadership Team

For detailed biographical information of Hydro One Limited board members and senior leadership, go to **www.HydroOne.com/Investors**

1. **David Denison,** O.C., FCPA, FCA
   Chair of the Board
2. **Ian Bourne,** ICD.D, F.ICD
   Board Chair, Ballard Power Systems
3. **Charles Brindamour**
   CEO, Intact Financial Corporation
4. **Marcello (Marc) Caira**
   Vice Chair, Restaurants Brands International
5. **Christie Clark,** FCA, FCPA
   Director, Loblaw Companies
6. **George Cooke**
   Board Chair, OMERS Administration Corp
7. **Margaret (Marianne) Harris**
   Board Chair, IIROC
8. **James Hinds**
   Former Board Chair, IESO and OPA
9. **Kathryn J. Jackson,** PH.D
   Director, Portland General Electric
10. **Roberta Jamieson** O.C., C.M., I.P.C, LL.B, LL.D (HON)
    President and CEO, Indspires
11. **Hon. Frances L. Lankin,** O.C., P.C., C.M.
    Member of Senate of Canada
12. **Philip S. Orsino,** O.C., FCA, FCPA
    Director, Bank of Montreal
13. **Jane Peverett,** FCMA, ICD.D
    Director, Canadian Imperial Bank of Commerce
14. **Gale Rubenstein**
    Partner, Goodmans LLP
15. **Mayo Schmidt**
    President and CEO, Hydro One Limited

15. **Mayo Schmidt**
    President and CEO
16. **Greg Kiraly**
    Chief Operating Officer
17. **Judy McKellar**
    EVP, Chief Human Resources Officer
18. **Ferio Pugliese**
    EVP, Customer Care & Corporate Affairs
19. **James (Jamie) Scarlett**
    EVP, Chief Legal Officer
20. **Chris Lopez**
    Senior Vice President, Finance

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Customer Inquiries

Customer Service:
1.888.664.9376 or
CustomerCommunications@HydroOne.com

Report an Emergency (24 hours):
1.800.434.1235

Shareholder Services
If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1
1.514.982.7555 or 1.800.564.6253
service@computershare.com

Institutional Investors and Analysts
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Media.Relations@HydroOne.com

Sustainability
Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impactson both. To learn more, visit www.HydroOne.com/OurCommitment

Stock Exchange Listing
Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

Independent Auditors
KPMG LLP

Equity Index Inclusions
Dow Jones Select Utilities (Canada) Index
FTSE All-World Index Series
MSCI World (Canada) Index
S&P/TSX Composite Index
S&P/TSX Utilities Index
S&P/TSX Composite Dividend Index
S&P/TSX Composite Low Volatility Index
S&P/TSX Composite High Dividend Index

Debt Securities
For details of the public debt securities of Hydro One and its subsidiaries, please refer to the "Debt Information" section under www.HydroOne.com/Investors

Online Information
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Common Share Dividend Information

*2018 Expected Dividend Dates**

Record Date	Payment Date
March 13, 2018	March 29, 2018
June 12, 2018	June 29, 2018
September 11, 2018	September 28, 2018
December 11, 2018	December 31, 2018

*Subject to Board approval

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

Dividend Reinvestment Plan (DRIP)
Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit www.HydroOne.com/DRIP or Computershare Trust Company of Canada at www.InvestorCentre.com/HydroOne

Regulatory Stakeholders

Hydro One is committed to understanding the interests of maintaining and enhancing long-term relationships with its regulatory stakeholders.

Ontario

Provincial Government,
Ministry of Energy
Policy, legislation, regulations

Ontario

Ontario Energy Board (OEB)
Independent electric utility price and service quality regulation

ieso
Power to Ontario.
On Demand.

Independent Electricity System Operator
Wholesale power market rules, intermediary, North American reliability standards

National Energy Board
Office national de l'énergie
Canada

National Energy Board
Federal regulator, international power lines and substations

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation
Continent-wide bulk power reliability standards, certification, monitoring

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Investing in Hydro One offers a unique opportunity to participate in the transformation of a premium large-scale utility. We offer a strong investment grade balance sheet, predictable multi-year growth with strong cash flows and an attractive dividend. Our highly accomplished management team is taking the opportunity to transform the organization into a commercially oriented, performance-driven culture focused on improving productivity and customer service.

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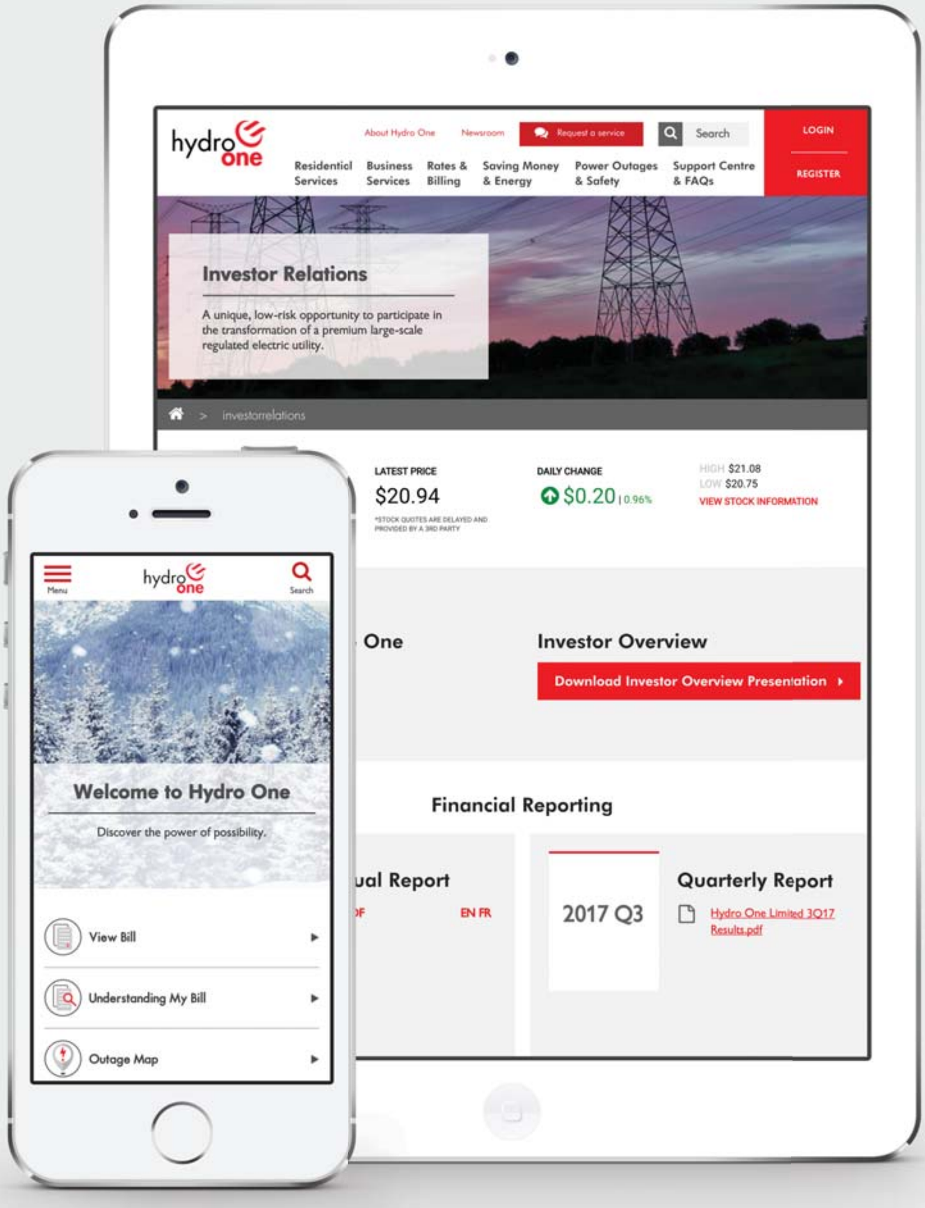

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IDENTIFYING CUSTOMER NEEDS

Hydro One uses a variety of customer engagement activities to inform its understanding of the outcomes transmission customers care most about, as well as the level of spending and mix of investments that customers would most like to see included in Hydro One's investment plan. The feedback received from customers through these engagement activities is an important and direct input into Hydro One's investment planning process. Consequently, Hydro One's capital expenditure plan is aligned with and responsive to the customer needs and preferences that Hydro One has identified.

Hydro One's customer engagement activities, their results, and their outcomes are described in detail in the Transmission System Plan ("TSP"). Section 1.2 TSP at Exhibit B, Tab 1, Schedule 1 describes the regional planning process including how distributors and other customer groups are engaged in planning activities and what activities are planned or in progress. Section 1.3 of the TSP describes the various initiatives through which Hydro One developed an understanding of the specific needs and preferences of customers, including a customer engagement survey that was carried out specifically to inform the TSP. The following attachments are included at TSP 1.3:

- Attachment #1 - Customer Engagement Survey
- Attachment #2 - Stakeholder Engagement Session Presentation Slides
- Attachment #3 - Stakeholder Session Notes
- Attachment #4 - Reliability Risk Summary
- Attachment #5 – Large Tx Customer Satisfaction Survey Report
- Attachment #6 – OGCC Customer Satisfaction Survey

Customer initiatives are also summarized in Attachment 1 to this exhibit (Appendix 2-AC of Chapter 2 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications*). Hydro One will continue to engage with customers through these initiatives and forums, assessing them on a regular basis to identify potential improvements and new approaches.

Feedback gathered from customer initiatives has been inputted directly into Hydro One's investment planning process as described in Section 2.1 of the TSP, and the way in which the proposed capital expenditure plan reflects the outcomes valued by customers is discussed in Section 3.2 of the TSP.

Appendix 2-AC
Customer Engagement Activities Summary

Customer engagement activities	Customer needs and preferences identified through engagement activity	Actions taken to respond to needs and preferences
Customer Engagement Survey (LDCs)	Improve reliability, infrastructure, and outage communication.	Adjustments to investment timing were made to ensure that customer needs, preferences, and feedback were appropriately reflected in the plan, and that emerging execution risks and financial considerations were addressed. Where investments to address customer needs, preferences, and feedback were changed (deferred or advanced) due to execution considerations, the impacts to customer satisfaction were documented and communicated to enable further trade-off discussions and any mitigation measures. An example of an investment that aligns with the customers' needs is the investment for Circuit Switchers for Outlier Improvement - AIP006247. This investment is proposed to improve the reliability of some of the worst performing delivery points (outliers).
Customer Engagement Survey (End Users)	Improve rate power quality, reliability, and infrastructure.	An additional investment was included in the plan to address power quality: (1) Customer Power Quality (Tx) Projects - AIP005536 (The stations to install capacitor switchers are selected based on the severity of transient over voltages and the complaints received from industrial customers.)
Customer Engagement Survey (Generators)	Improve customer service, reliability, infrastructure, and improved outage communications.	Hydro One adjusted several projects to align with Generator needs and preferences, including" (1) The Bruce B project was adjusted to align with Bruce Power's preferred schedule, which reflecting the need for outage coordination and coordination of infrastructure renewal. (2) Circuit Breaker Maintenance and Refurbishment - AIP001044 (OPG Darlington has provided their overhaul schedule for their generating units, with the expectation that we will complete the refurbishment of the breakers within the timing of the unit overhaul, in order to minimize requirements for outages for performing this type of maintenance in the future.) (3) Bruce B SS - AIP005165 (Investment aligned with Bruce Power outages at the Bruce Nuclear Generating Station.) (4) Cherrywood TS - AIP005214 (Aligned with the OPG Pickering Generation Station shut down.) (5) Beck 1 SS - AIP005297 (Aligned with the OPG canal refurbishment project.)
Customer Satisfaction Surveys (Refer to TSP 1.3.3)	Reduce power quality events, reduce timelines for connection estimates, lower connection costs, and improve communications and transparency.	Hydro One is investigating the potential ways to incorporate power quality results into Reliability Reports and contemplating educational engagement with customers. The company is also exploring alternate ways to plan and estimate customer projects to reduce timelines, and increase the increase the number of customer reports to improve visibility to the products and services purchased by customer.
Large Customer Account Management (Refer to TSP 1.3.4.2)	Improve communication, especially with respect to outages.	Account Executives are assigned to large customers, including large distribution accounts. Account Executives meet with customers on a regular basis to ensure that the needs of customers are identified and discussed, and action plans are developed to address these needs. Account Executives also communicate changes or important information to large customers. Account Executives also proactively engage with customers to review and coordinate planned outage activities to minimize impacts and optimize opportunities for both Hydro One and customers to plan and execute work on their respective facilities. Investments resulting from direct communication by Account Executives include Enfield TS and the Seaton MTS Connection.

Customer engagement activities	Customer needs and preferences identified through engagement activity	Actions taken to respond to needs and preferences
Ontario Grid Control Centre’s (“OGCC”) Customer Operating Support Group (Refer to TSP 1.3.4.3)	Improve outage coordination and communication with customers.	Bi-annual customer meetings throughout the province provide an opportunity for Hydro One to coordinate outage planning activities with customers. The OGCC sends customers a customized report of planned outages. These reports contain information on outage start and end dates, the equipment involved, purpose, recall time and schedule profile. Hydro One also provides information on the Company's plans, particularly with respect to outages, for the balance of the year and/or the next scheduling year. During these meetings, customers also have an opportunity to bring forward their maintenance plans for their facilities.
Large Customer Conferences (Refer to TSP 1.3.4.4)	Improve communication with customers and improve reliability and power quality.	The conference now provides large customers with an opportunity to discuss their interests, raise concerns with representatives and executives from several Hydro One lines of business, hear about Hydro One’s planned investments and activities, and ask questions.
Oversight Committees and Working Groups (Refer to TSP 1.3.5)	Improve communication with customers and improve reliability and power quality.	Oversight committees and working groups engage and obtain feedback from customers about their ongoing operational needs and preferences. Working groups review proposed annual work plans and can provide early insights with respect to future investment needs.

FIRST NATIONS AND MÉTIS ENGAGEMENT STRATEGY

1. BUILDING RELATIONSHIPS WITH INDIGENOUS COMMUNITIES

Hydro One serves eighty eight First Nation communities representing close to 22,000 distribution system customers. While Indigenous communities (First Nation communities and Métis Councils) in Ontario are not directly connected to the transmission system, Hydro One's transmission business may impact them in other ways. In particular: (1) Hydro One transmission assets are located on reserve lands of twenty three First Nation communities and within the traditional territories of Indigenous communities; (2) The company has large projects that cross or may impact First Nation communities such as the Niagara Reinforcement Project; and (3) Hydro One enters into business partnerships with First Nation communities. Hydro One is committed to developing and maintaining relationships with Indigenous communities and adapting its business practices in response to evolving industry best practices and legal rights of Indigenous communities and individuals.

This exhibit outlines: (i) Hydro One's ongoing efforts to engage with Indigenous communities; (ii) the needs and preferences that have been identified through those activities as they relate to Hydro One's transmission system; and (iii) the steps Hydro One has taken to address those needs and preferences. The exhibit also describes the company's overall approach to Indigenous relations and highlights areas where the company's transmission business affects Indigenous communities. To a certain extent, the information in this exhibit reflects the fact that the company also has a relationship with Indigenous communities and people as distribution customers and that distribution system issues naturally arise during the company's engagement sessions with Indigenous communities.

Hydro One developed an Indigenous Relations Strategy Framework to guide its Indigenous relations and engagement with a view to becoming the primary business partner to Indigenous communities by 2021. To realize this vision, Hydro One is continuing to develop its relationships with Indigenous communities by providing employment opportunities, developing business relationships and by investing in and engaging with communities. Hydro One meets with Indigenous communities on a regular and ongoing basis to listen to feedback, conduct meaningful engagement on capital investment transmission and distribution projects and to deliver various customer-based programs.

As part of Hydro One's efforts to build and maintain strong relationships with Indigenous communities, Hydro One obtained Bronze Level Certification under the Canadian Council for Aboriginal Business' *Progressive Aboriginal Relations Program* in 2017 and will seek a Silver certification starting in 2019. The certification program reflects Hydro One's performance in Indigenous relations and indicates to Indigenous communities that Hydro One is a good business partner, is a great place to work and is committed to prosperity in Indigenous communities.

2. ENGAGEMENT SESSIONS – PROCESS AND OUTCOMES

To build and maintain sustainable relationships with Indigenous communities, Hydro One hosts formal provincial and regional engagement sessions with Indigenous communities and visits First Nation communities located on reserve on a regular basis to address community concerns, provide information about Hydro One programs or Provincial electricity programs and to explore potential employment, business and investment opportunities.

In 2017, Hydro One began hosting formal provincial and regional engagement sessions with Indigenous communities. In addition to strengthening relationships with Indigenous communities, the key objectives of these sessions are to present information on Hydro One's customer programs and initiatives, to hear transmission and distribution related concerns and to identify potential solutions moving forward. Participants have discussed transmission and distribution matters including affordability, reliability, access rights and procurement and employment opportunities.

Provincial engagement sessions were held on February 9 and 10, 2017 and February 21, 2018 with the eighty eight First Nation communities that Hydro One serves through its distribution system. The session report and presentations from the 2018 engagement session are included as Attachments 1 to 4 to this exhibit. A provincial engagement session was also held with the twenty nine Métis Councils represented by the Métis Nation of Ontario on May 13, 2017 with another session planned for 2019. Presentations and the reports from Hydro One's engagement with First Nation and Métis communities are available on the company website.[1]

Regional engagement sessions were held in 2017 and 2018 with First Nation communities and Metis Councils to discuss region-specific matters related to affordability, reliability, access rights, and procurement and employment opportunities. In 2017, Hydro One held over 130 meetings with First Nation communities and twenty nine meetings with Métis Councils.

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[1] Métis Nation Engagement Session materials available online at: https://www.hydroone.com/about/indigenous-relations/metis-nation-engagement-session and First Nation Engagement Session materials available online at: https://www.hydroone.com/about/indigenous-relations/first-nations-engagement-sessions (accessed February 19, 2019)

In 2019 Hydro One will actively focus on: (1) the 23 First Nation communities with transmission assets located on reserve; (2) communities that Hydro One has business partnerships with such as the Six Nations of the Grand River, Mississaugas of the Credit First Nation, Saugeen First Nation, Chippewas of Nawash; (3) communities impacted or affected by projects. The initiatives described above and planned for 2019 will allow Hydro One to address the OEB's direction in EB-2016-0160 that Hydro One improve its customer engagement process by seeking "timely and meaningful input from First Nations representatives."

Feedback from Métis communities focused on procurement and employment opportunities. Feedback from First Nation communities focused on affordability, reliability, liability and access rights, partnerships and employment opportunities. These are detailed along with steps Hydro One is taking to address these issues, in the next section.

Of these issues, affordability, reliability and access rights were the most significant concerns identified in respect of First Nations' relationship with Hydro One as a transmitter and a distributor, as the case may be. Hydro One notes that affordability issues relate primarily to the distribution side of the business and are alleviated in part by the Fair Hydro Plan.

3. ADDRESSING THE NEEDS AND PREFERENCES OF FIRST NATIONS COMMUNITIES AND CUSTOMERS

The key actions Hydro One is taking to address the needs and preferences of Indigenous customers and communities are summarized in the table below:

Common Issues		Actions Taken to Address Issues
Affordability	• Some First Nation communities felt disproportionately impacted by high electricity costs at the individual customer and band levels.	• Hydro One's Get Local initiative helped customers reduce their arrears. • Provincial initiatives including the Fair Hydro Plan, the First Nations Conservation Program and the Affordability Fund helped customers with their bills.
Reliability	• Frequent or lengthy outages impacting electricity supply to on reserve businesses. • First Nation community growth plans limited by existing power loads and capacity.	• Aging assets are being replaced, as described in Attachment 3 titled "First Nations Reliability Performance". • New technology (Distance-to-Fault) is being leveraged to monitor unplanned outages. • The number of planned outages has been reduced by bundling renewal work where possible. • Hydro One is performing forestry maintenance on reserve more frequently. • First Nations represented by Anwaatin Inc. intervened in the 2017 Hydro One distribution rate application and settled on a DER solution to address power reliability issues. The battery storage solution will be in-serviced on the Aroland First Nation.
Liability and Access	• Outdated access rights/permits and compensation issues for transmission and distribution assets on reserve land and within traditional territories • Notification protocols for planned and non-planned disconnection work.	• Progressed with negotiations to settle outstanding real estate agreements. • Hydro One's Indigenous Relations Group and Real Estate Group are working together to develop an Indigenous Integration Plan to address access rights in a fair and timely manner. • Hydro One's Indigenous Relations Group and Provincial Lines and Forestry are working together and have developed an Indigenous Integration Plan which includes communication protocols between the company and the First Nation communities it

Common Issues		Actions Taken to Address Issues
		serves. • The Indigenous Relations department at Hydro One is leading these efforts in close consultation with the Real Estate, Legal and Regulatory Affairs departments to resolve these outstanding matters. The team is targeting to resolve the majority of outstanding agreements by year-end 2018.
Partnerships and Business Opportunities	• Indigenous communities expressed interest in more procurement opportunities, ownership opportunities and other business partnerships.	• Hydro One increased available procurement opportunities and will continue to do so over the next three years. Hydro One delivered eight Indigenous Procurement Workshops in 2018. • Hydro One developed a tool to set aside a portion of its contracts for Indigenous business. • Hydro One signed equity partnership agreement on the Niagara Reinforcement Project with the two affected First Nation communities.
Employment and Training	• Indigenous communities are interested in more employment opportunities and training.	• Hydro One increased employment with new permanent hires in 2017 and set targets and developed plans to increase Indigenous employment over the next three years. • Hydro One will continue to participate in career fairs and workshops promoting employment and training. • Hydro One created the Indigenous Network Circle, an internal group of Indigenous employees promoting Indigenous employment and training.

Hydro One will continue to engage and work with Indigenous communities as it develops and executes programs intended to provide better service and customer care and works to build and maintain positive relationships with Indigenous communities across Ontario.

4. PROGRESS ON FIRST NATIONS PERMIT NEGOTIATIONS

Hydro One owns assets on First Nation reserve lands and within the traditional territories of Indigenous peoples. Hydro One is committed to developing and maintaining relationships with Indigenous peoples that demonstrate mutual respect for one another. Hydro One recognizes that Indigenous peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. In EB-2016-0160, the OEB found that Hydro One "should continue to work diligently with affected First Nations to resolve outstanding permit issues in a timely manner with the objective of providing appropriate compensation while respecting First Nations rights."

A number of First Nation communities have stated that they have outstanding agreements with Hydro One. The majority of these outstanding agreements relate to Hydro One's assets on reserve and/or within traditional territories. More specifically the common issues are: outdated Memoranda of Understanding, Payment In Lieu of Tax Agreements, Agreement and Annual Land Rental Payments and Transmission Permit. In the EB-2016-0160 decision, the OEB directed Hydro One to continue to work with affected First Nations to resolve outstanding permitting issues in a timely manner with the objective of providing appropriate compensation while respecting First Nation rights.[2] The Indigenous Relations department at Hydro One is leading these efforts in close consultation with the Real Estate, Legal and Regulatory Affairs departments to resolve these outstanding matters. As of February 2019, five of the previously outstanding agreements have been finalized and are with the federal government for final permit issuance, three of the previously outstanding agreements are in active negotiations and a newly expired agreement has entered into the negotiation phase.

[2] EB-2016-0160, Decision and Order (revised November 1, 2017) at p. 77

2nd Annual Hydro One and First Nations Engagement Session
Slivernightingale Room, Casino Rama
Wednesday, February 21, 2018

SESSION REPORT

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WELCOME

Mr. Phil Goulais, Session Facilitator, called the meeting to order and introduced Elder Mryna Watson, Chippewas of Rama First Nation. Elder Watson provided the opening prayer. Mr. Goulais introduced Chief Rodney Noganosh, Chippewas of Rama First Nation, to provide welcoming remarks. Chief Noganosh welcomed the participants to their territory and thanked them for coming. He specifically thanked their leadership who had been working on a new relationship with Hydro One. He thanked Hydro One for the reduction in delivery rates for First Nations communities and he was looking forward to working together to address more issues for the betterment of their First Nation communities.

Welcome remarks were also provided by Mayor Steve Clarke, City of Orillia. He welcomed all participants and stated that they had a strong working relationship with the Chippewas of Rama First Nations and met on a regular basis to discuss issues in common. He said that he had learned a lot about First Nations and continued to learn; he stated that relationships were built on true collaboration. He also welcomed the representatives from Hydro One; the City of Orillia had recently gone through negotiations with Hydro One and he welcomed them back to the city.

Chief Ava Hill, Six Nations, provided welcoming remarks on behalf of the Chiefs of Ontario Chiefs Committee on Energy (CCOE). She thanked them all for taking the time to attend this important session. She provided background information on the CCOE stating that Government of Ontario wanted to sell Hydro One shares and the Chiefs wanted to be part of that. Resulting discussions brought up many issues that First Nations had with Hydro One so two committees were set up - one to deal with purchasing the Hydro One shares and the other to deal with outstanding grievances. The grievance one was further split into two groups – one to deal with high hydro rates and the other to deal with hydro lines crossing First Nation lands for which compensation was required. Chief Hill stated that these groups were not negotiating on behalf of First Nations but rather facilitating a relationship between the First Nations and Hydro One..

She mentioned that high hydro rates have been on ongoing issue in her community and they appreciated the commitment that Hydro One had made to eliminate the delivery charge to First Nation community homes. This had a huge impact on First Nation community members. She also mentioned that Hydro One staff had come to her community to talk with members about how to deal with their outstanding hydro bills. This could be done in any community served by Hydro One. She stated that the next priority for the CCOE is to work towards delivery charge relief for all Band owned buildings on the First Nations and then they would work on getting the same commitment for privately owned businesses on the reserve. Once the band owned buidings and businesses has been resolved, she explained that they will then work on getting the same commitment for off-reserve members.

On December 29, 2017, an agreement was reached with the Government of Ontario for the First Nations to purchase just over 14 million of Hydro One shares worth $260M. She said that they were proud of this partnership that would benefit future generations. She said that the work they had undertaken with Hydro One was reconciliation in action; reconciliation involved everyone, she said, not just First Nations and government. They all had a mutual interest in addressing the challenges and First Nations needed to come up with their own solutions she said and take advantage of their opportunities.

Chief Hill stated that they needed to deal with racism that still existed today in Canada; a change of attitude is needed, Canadians needed to be educated about First Nations.

She acknowledged the efforts of Hydro One; the operations of Hydro One had changed since the new executive team had come in. She also recognized the work of the Chief Committee on Energy and encouraged all the chiefs in the room to lobby the Government of Ontario to support work they still need to do with Hydro One. She also encouraged them to review the Long-Term Energy Plan in detail, as there was a lot going on in the province. She thanked the Chiefs for their strength and perseverance in continuing this work.

HYDRO ONE ADDRESS

Mr. Ferio Pugliese, Executive Vice President, Customer Care and Corporate Affairs, Hydro One, provided opening remarks on behalf of Hydro One. He thanked the Elder for her prayer and Chief Noganosh for welcoming them all to their territory. He also thanked Chief Hill for her opening remarks and highlighted her leadership on the CCOE and he thanked them all for coming and taking time out of their busy schedules. He said that this day was designed for the participants and it was a second one of what they wanted to host on an annual basis. Last year, they held a candid dialogue and he hoped that they could do the same this year.

In the last few years, Hydro One has gone through a IPO process which took them from a Crown Corporation to a privately held company. He said that they gave them increased opportunities to develop partnerships and the flexibility to grow their business. They have also changed their organization to a focus on putting the customer first; they provided a life sustaining service and they had to improve as an organization. Their work with First Nation communities was identified as a priority for Hydro One and he believed that they have made some significant progress.

He said that there have been three areas of focus including: education for the public, communities and leadership around how electricity generation and distribution worked in Ontario; advocacy to support First Nations such as the advocacy work undertaken by Hydro One on the First Nation delivery credit work with the Ontario Energy Board last year; and, First Nations engagement and outreach including community visits. They have also completed training with First Nations administrators on billing, collections and other issues and that had worked well.

Mr. Pugliese stated that they were also open to talking about capital projects and mentioned the Niagara Reinforcement Project (NRP) as an example. They had been paying for an asset that was not complete and not in service but now they would work together on this and there would be significant benefits for all involved. Indigenous procurement was another example. A6N was a Joint Venture between Six Nations of the Grand River Development Corporation (51% ownership) and Aecon Group Inc. (49% ownership). The company performs utility related work in southwestern Ontario. He said that Hydro One has delivered $23M last year in Indigenous procurement and this will be increased in future years.

He stated that the First Nations were valued partners; he encouraged them to take a look at Ontario's Long-Term Energy Plan. There were many opportunities for economic development but also it provides information on how the energy system was changing in the province. Their focus was on capacity building for everyone and on sustainability. He thanked them all for attending this session and he looked forward to ongoing engagements in their communities or regions.

INTRODUCTIONS

1. **Mr. Phil Goulais, Facilitator, Nipissing First Nation:** Personal introduction
2. **Mr. Stan Judge, Consultation Officer, Shawanaga First Nation:** Personal introduction
3. **Chief Elaine Johnston, Serpent River First Nation:** Chief Johnston thanked Hydro One for coming to her community for outreach, as this was positive experience.
4. **Ms. Amelia Williams, Chiefs of Ontario:** Personal introduction
5. **Amy Lickers, Chiefs of Ontario:** Personal introduction
6. **Chief Bruce D. Archibald, Taykwa Tagamou Nation:** Personal introduction
7. **Chief Rodney Noganosh, Chippewas of Rama First Nation:** Chief Noganosh mentioned that they had recently passed their land code vote with 91% of the membership's support.
8. **Councilor Dan Shilling, First Nation Manager, Chippewas of Rama First Nation:** Personal Introduction
9. **Elder Myrna Watson, Chippewas of Rama First Nation:** Personal introduction
10. **Chief Ava Hill, Six Nations of the Grand River:** Personal Introduction
11. **Councilor Wray Maracle, Six Nations of the Grand River:** Personal introduction
12. **Darryl Hill, A6N Utilities LP:** Personal introduction
13. **Daniel Charbonneau, Indigenous Relations, Hydro One:** Personal introduction
14. **Brian George, Indigenous Network Circle, Hydro One:** Personal introduction
15. **Kevin Hill, Indigenous Network Circle, Hydro One:** Personal introduction
16. **Kyla Thistle, Contract Officer, Supply Chain, Hydro One:** Personal introduction
17. **Ferio Pugliese, Vice President, Customer Care and Corporate Affairs, Hydro One:** Personal introduction
18. **George Kakeway, Indigenous Relations, Hydro One:** Personal introduction
19. **Susan Wylie, Director, Supply Chain, Hydro One:** Personal introduction
20. **Cesar Martinez, Customer Care Manager, Hydro One:** Personal introduction
21. **Tania Jacko, Energy Advisor, Whitefish River First Nation:** Personal introduction
22. **Joel Strickland, Vice-President, Longnorth Capital Group:** Personal introduction
23. **Jake Linklater, President, Longnorth Capital Group:** Personal introduction
24. **Chief Rick Allen, Constance Lake First Nation:** Personal Introduction
25. **Councilor Peggy Mansur, Chippewas of Nawash First Nation:** Personal introduction
26. **Michael Harney, Economic Development Officer, Nipissing First Nation:** Personal introduction
27. **Jay Armitage, Hydro One:** Personal introduction
28. **Steven Mantifel, Hydro One:** Personal introduction
29. **Chief Jason Fisher, Moose Deer Point First Nation:** Personal introduction
30. **Chief Gerry Duquette Jr., Dokis First Nation:** Personal introduction
31. **Chief Lloyd Myke, Magnetewan First Nation:** Personal introduction
32. **Chief Warren Tabobondung, Wasauksing First Nation:** Personal introduction
33. **Councilor Richard Jason, Shawanaga First Nation:** Personal Introduction
34. **Harvey Thunderchild, Wahnapitae First Nation:** Personal Introduction

35. **Shane Innes, Hydro One:** Personal introduction
36. **Kevin Hill, Indigenous Network Circle, Hydro One:** Personal introduction
37. **Councilor Gary Smith, Naicatchewenin First Nation:** Personal introduction
38. **Chief Robin McGinnis, Rainy River First Nation:** Personal introduction
39. **Chief Steve Miller, Atikamekshang Anishnawbek:** Personal Introduction
40. **Grand Chief Francis Kavanagh, Treaty #3:** Personal introduction
41. **Chief Wayne Smith, Naicatchewenin First Nation:** Personal introduction
42. **Stan Kapashesit, Moose Cree First Nation:** Personal introduction
43. **Derek Chum, Indigenous Relations, Hydro One:** Personal introduction
44. **Tausha Esquega, Indigenous Relations, Hydro One:** Personal introduction.
45. **Chief Edward Wawia, Red Rock Indian Band:** Personal introduction
46. **Jeff Corbiere, Renewable Energy Coordinator, M'Chigeeng First Nation:** Personal introduction.
47. **Albalina Metatawabin, General Manager, Mushkegowuk Tribal Council:** Personal introduction.
48. **Chief R. Donald Maracle, Mohawks of the Bay of Quinte:** Personal introduction.
49. **Chief Philip Franks, Wahta Mohawks:** Personal introduction
50. **Christine Goulais, Hydro One:** Personal introduction.
51. **Councilor Larry Sault, Mississaugas of the New Credit First Nation:** Personal introduction.
52. **Councilor Lawrence Solomon, Sagamok Anishnawbek First Nation:** Personal introduction.
53. **Marlene Stiles, Economic Development Officer, Chippewas of Georgina Island First Nation:** Personal introduction.
54. **Chief James R. Marsden, Alderville First Nation:** Personal introduction.
55. **David Mowat, Mississaugas of Scugog Island First Nation:** Personal introduction.
56. **Councilor Patrick Brennan, Henvey Inlet First Nation:** Personal introduction.
57. **Chief Andrew Aguonie, Sheguiandah First Nation:** Personal introduction.
58. **Chief Dean Roy, Sheshegwaning First Nation:** Personal introduction.
59. **Councilor Jim Meness, Algonquins of Pikwakanagan First Nation:** Personal introduction.
60. **Jeff Smith, Hydro One:** Personal introduction.
61. **Erika Dawson, Hydro One:** Personal introduction.
62. **Councilor Ted Williams, Chippewas of Rama First Nation:** Personal introduction.
63. **Chief Vanessa Powassin, Animakee Wa Zhing #37:** Personal introduction.
64. **Robin Koistinen, Temagami First Nation:** Personal introduction.
65. **Councilor Laurie Hockaday, Curve Lake First Nation:** Personal introduction.
66. **Warren Lister, Vice President, Customer Service, Hydro One:** Personal introduction.
67. **Councilor Anthony Petten, Ginoogaming First Nation:** Personal introduction.
68. **Councilor Ernest Waboose, Ginoogaming First Nation:** Personal introduction.
69. **Gary Allen, Executive Director, Grand Council Treaty #3:** Personal introduction.
70. **Sarah Luce, S. Barnett and Associates (Wabigoon Lake First Nation):** Personal introduction.
71. **Chief Gregory Nadjiwon, Chippewas of Nawash Unceded First Nation:** Personal introduction.
72. **Chief A. Myeengun Henry, Chippewas of the Thames First Nation:** Personal introduction.

73. **Valerie George, Consultation Coordinator, Chippewas of Kettle and Stoney Point First Nation:** Personal introduction.
74. **Sara Jane Souliere, Indigenous Relations, Hydro One** : Present
75. **Chief Reginald Niganobe, Mississaugas #8 First Nation:** Personal introduction.
76. **Ron Allen, Nigigoonsiminikaaning First Nation:** Personal introduction.
77. **Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island):** Personal introduction.
78. **Vivian Yoanidis, Director, Recruitment, Diversity & Inclusion, Hydro One:** Personal introduction.
79. **Alicia Sayers, Hydro One:** Personal introduction.
80. **Chief Joel Babin, Wahgoshig First Nation:** Personal introduction.
81. **Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One:** Personal introduction.
82. **Chief Duke Peltier, Wikwemikong Unceded First Nation:** Personal introduction.
83. **Tabatha Bull, Senior Manager, First Nations and Metis Relations, Independent Electricity System Operator**: Personal introduction.
84. **Erika Dawson, Indigenous Relations, Hydro One:** Present
85. **Emily Spitzer, Indigenous Relations, Hydro One:** Present

HYDRO ONE CUSTOMER SERVICE

Mr. Cesar Martinez, Customer Care Manager, Hydro One, provided an overview of his powerpoint presentation entitled “Customer Programs”. To date, he explained, they had visited over 1,500 customers in 35 Communities across the province. In addition, there have been a reduction of customers in arrears by 2,400 since January 2017, a reduction from 8,900 to 6,500. Hydro One launched a blitz in August 2017 to reach out to customers who were not receiving the First Nations Delivery Credit. Since then, they had reduced that number by 1,600 to a total of 4,891. He asked for assistance in making sure that their members registered with their status cards for the delivery credit, as there were still approximately 5000 customers who were not registered. They had also doubled the Ontario Electricity Support Program (OESP) enrollments for First Nations customers through their local efforts from 1,600 to 3,400. Enrollment in these programs should be much higher and stated that Hydro One could work with First Nation customers to take advantage of their programs.

He provided a list of those communities where there were customers who had not yet signed up for the First Nations Delivery Credit (FNDC). Hydro One will be attempting to have 100% enrollment in FNDC by the end of 2018 to ensure all customers are receiving the full benefit of the credit. In order to achieve this, Hydro One needed the support of the First Nations and they would also be looking at increasing their local visits, identify seasonal properties where non-status residents live (which do not qualify for the FNDC) and initiating social media and other marketing campaigns. It was important because the credit was significant and he gave an example of a bill which took the total charge from $699 to $ 399 from the previous year in the same month.

Mr. Martinez encouraged them to get in touch with Hydro One to request a local session which could include one-on-one meetings with customers, assist with enrollments in the different programs and answer any questions or concerns that local customers might have.

Chief Elaine Johnston: Chief Johnston asked that the specific numbers for her First Nation could be sent to her so they would know how many have been enrolled for the FNDC and how many more need to enroll. Mr. Martinez stated that this could be sent to her.

Chief ______: The Chief asked when they could expect that this FNDC would be available to their off-reserve members, as it should apply to all First Nations. Mr. Martinez said that some of their other programs do apply off-reserve and could be accessed by off-reserve members but the FNDC, at this point in time, was only for on-reserve residents. Chief Ava Hill, Chiefs Committee on Energy, added that they were working on this and that they were proceeding in stages. They next stage was an attempt to get the FNDC apply to all band owned buildings, then for private businesses on-reserve and then they were going to work on getting the same benefit for their off-reserve members. She said they agreed that the benefit should be available to all First Nations regardless of where they resided and she asked that all the leaders lobby the province whenever possible.

Chief R. Donald Maracle: Chief Maracle asked how many people had not yet signed up for the FNDC and the response was that there were approximately 5000. The Chief asked if their 911 addresses had been sent and the response was that they had not. The Chief said that the Chiefs Committee on Energy would work on asking their Chiefs to send their 911 lists and Mr. Martinez said that these could be sent to Chris Cooley or himself.

Robin Koistinen, Temagami First Nation: Ms. Koistinen suggested that these First Nation customers might also be being charge tax and asked how retroactive that would be if they provided the information to take that off their bills. She also asked about how retroactive for the FNDC or the OESP. Mr. Martinez mentioned that for the OESP, it would not be retroactive; he also noted that people have to re-enroll for that after two years so that was something they had to work on as well. Benefit for the FNDC could go back to July 2017. For the taxes, he believed that it went back on during the current fiscal year.

Chief Elaine Johnston: Chief Johnston said that she had some concerns with providing the 911 lists as there were issues with this since it did not always co-relate to the residences. She also added that if the First Nations were not enrolling again for the OESP, maybe it was a communication issue. Mr. Martinez agreed that it was likely a communication issue; the letter goes out by mail 90 days before but people were not reading it. They needed to look at communicating this information in different ways.

Councilor Peggy Mansur, Chippewas of Nawash First Nation: Councilor Mansur asked if there were any representatives in the room from the welfare administrator organizations and was told that there was not. She suggested that they might want to increase their communications with this group and some others who would be relevant to these discussions. Mr. Martinez said that there was some communication but not enough; they have attempted to reach out to the welfare administrators in the communities when they were there. Councilor Mansur suggested that more cooperation was needed in coordinating community visits. Mr. Martinez agreed with this and would look at different groups that they could meet with locally and regionally.

Valerie George, Chippewas of Kettle and Stoney Point First Nation: Ms. George asked if they could get an extension on the OESP re-enrollment deadline. Mr. Martinez stated that there was no deadline but he said that they would look at the letter again to check for clarity and also follow up with those customers who have not re-enrolled. Hydro One also wanted to talk to the Ontario Energy Board about making that transition easier for the customer.

CHIEFS OF ONTARIO ADDRESS

Ms. Amy Lickers, Chiefs of Ontario, provided an overview of her powerpoint presentation entitled "Ontario First Nations Sovereign Wealth LP – Update February 2018". Ms. Lickers explained that she was from Six Nations and she worked at the Chiefs of Ontario; she worked with a number of Chiefs Committee there. For the past few years, she said, they have been working on an agreement with the province to acquire Hydro One shares. 129 First Nations have signed on to be shareholders in Hydro One; she provided the ownership structure and an overview of the agreement.

Currently they had an interim board of directors in place and they were in the process of electing board members and they were hoping to ratify a new board at the All Ontario Chiefs Conference in June 2018. She asked that they contact their PTO for suggestions on who should be on the board. She said that they will grow the fund to $90M or 12 years, whichever comes first, so there was time for more discussions around a funding formula.

Chief _______: The Chief asked about if the First Nation did not have a PTO, how could they follow up on that. Ms. Lickers noted that there were a number of Independent First Nations and they have formed a group and suggested that could be avenue to participate.

PROGRESS ON PROCUREMENT/BUSINESS PARTNERSHIPS PANEL

Ms. Susan Wylie, Director, Supply Chain, Hydro One, introduced the panel including: Mr. Darryl Hill, A6N Utilities LP; Mr. Brian Johnson, Aecon-Six Nations Joint Venture; Chief Reginald Niganobe, Mississaugas #8 First Nation; and, Ron Allen, Nigigoonsiminikaaning First Nation.

<u>What are the top three challenges in working with Hydro One?</u>

Mr. Johnson stated that it was getting through a complicated procurement process. There were a number of documents needed and they were fortunate to have a partner in Aecon with a lot of resources to assist in getting that done. He suggested that stronger relationships would be helpful. Mr. Hill stated that they needed to meet with everyone involved in the project and clearly set out the milestones for the project. There were challenges to being a small company like theirs. Ms. Wylie stated that they could look additional education programs and more relationship building around the document requirements for procurement.

Mr. Johnson also suggested that they needed an avenue or process to identify the skills sets available in different Indigenous businesses. Ms. Wylie stated that they had been working with

Indigenous Relations to build that directory and outreach activities were being undertaken to have a better working knowledge of the business out there when the projects come up.

Mr. Allen noted that there were issues with Aboriginal set asides, as it was very hard to get in there and there seemed to be many different ways to get screened out as an Indigenous business. Ms. Wylie noted that Mr. Pugliese had mentioned their commitments and they were undertaking more outreach activities to get to know the capacity out there. Hydro One had committed to establishing a set aside process in 2018.

Chief Niganobe stated that they had experienced the procurement issues that have been mentioned and added that they had to build their capacity in order to take advantage of procurement opportunities.

<u>What advice do you have for Hydro One in working with the communities to build community capacity and enhance opportunities for Indigenous businesses?</u>

Mr. Hill suggested that they should have more Indigenous people to make those initial introductions and a good retention plan to keep them on. Mr. Johnson added that they should hold their contractors to socially responsible behaviour around engaging with Indigenous communities where there were projects on the First Nation's territory. It was also suggested that Hydro One should measure and know how their contractors do in this.

Ms. Wylie asked how they could support communities through increased communications. Mr. Allen stated that they needed support for their basic programs to get their people driver's licenses and they also needed to address employment issues such as working with unions. Ms. Wylie suggested that they could bring in their Labour Relations team to address that needs. Mr. Hill stated that they worked with unions every day and suggested that they could help with that.

<u>Final Panel Comments</u>

Chief Niganobe suggested that they could do more regional liaison; he said that they had trouble finding skilled labour but they do have people who could do more. Mr. Allen stated that they had a hard time with relationship building so they could use some help with that. Mr. Johnson said that they wanted to be part of the solution and wanted to provide even more opportunities to community businesses. Their goal was to hire 100% from Six Nations and to achieve that, they needed the help of their partners. Mr. Hill added that they had a good partnership with AECON and they wanted to ensure their community members would get more experience. He thanked Chief Ava Hill for her support and they looked forward to sharing their experiences with other First Nations.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): The Chief asked about maintaining cash flow and if they had a line of credit. Mr. Johnson agreed that this was challenging but, in their situation, their partner was AECON so they did not have to worry. Smaller companies would have trouble with this and he would suggest quicker milestone payments and keeping the lines of communication open to explain the situations

Councilor Larry Sault, Mississaugas of the New Credit First Nation: Councilor Sault stated that what he was seeing in the community was that they always looked for employees who had to have grade 12, but this was not always necessary depending on the position. They also should work with people to get their driver's licenses and those who have criminal records from the past. He also said that they should be challenging the unions on First Nation rights; First Nations have portable rights.

HYDRO ONE DIVERSITY AND INCLUSION

Vivian Yoanidis, Director, Recruitment, Diversity & Inclusion, Hydro One, provided an overview of her PowerPoint presentation entitled "Diversity and Inclusion at Hydro One". She provided information on Hydro One's Diversity and Inclusion Strategy, which had three main goals: to build a diverse workforce; to create a culture of inclusion; and, to be a leader in diversity and inclusion in the energy sector. She explained that background on the establishment of the Indigenous Network Circle. She also provided an overview of the company's commitment which included the following: hiring a Diversity & Inclusion Consultant to focus on Indigenous Outreach, Recruitment and Inclusion; hiring more Indigenous employees (regular hires, co-op/Internship, new graduates, Summer Outreach Program); visiting communities across the province sharing information about recruitment requirements and career opportunities; working with Hydro One Indigenous employees to educate and raise cultural awareness within the organization; engaging Indigenous communities in a dialogue regarding training and development partnerships; and, researching and adopting, as required, Indigenous employment and retention industry best practices.

Panel – Hydro One's Indigenous Network Circle

Mr. Kevin Hill introduced himself saying that he was from Six Nations, adding that he has been with Hydro One for many years and he was happy to see the focus on the Indigenous employees. He spoke to the importance of Indigenous Circle Network; he was proud to sit in a room with other First Nations people at Hydro One. As staff, it was important to have those links to their people.

Mr. Brian George stated that he was from Saugeen and had been a forester for Hydro One for 12 years. The Indigenous Circle Network was a good way for them to get involved in organization and they could provide more support for employees particularly new First Nation employees coming in.

Mr. Charles Doxtator-Young stated that he was from Six Nations. He stated that it was not easy coming from the reserve and joining Hydro One; it seemed far from where he thought he should be but it was important to provide for his family. The Network was a good way for him to be involved and promote careers at Hydro One to their First Nation youth.

Ms. Alicia Sayers stated that she was from Garden River First Nation and had been with Hydro One since 2009. As a young person, she said, she did not know what Hydro One was or what they did but she was not from a community served by Hydro One. She had started there in a summer position and she became fascinated by what Hydro One did so she joined the company full time when she graduated. She felt very isolated; she felt alone. She was happy to be part of the Network and they were there for the right reasons. She said that she believed in the company and what they were doing.

Steven Mantifel, Hydro One: Mr. Mantifel stated that the Network was new and he asked the panelists how they planned on engaging other Hydro One staff. Mr. Doxtator-Young responded that they have not yet set goals for the Network, as they were still building it. To him, he said, it made sense to make those connections because they wanted to share information with non-First Nations employees as well as First Nations employees. He said they were not quite there yet but the idea of non-First Nations group of employees, an ad-hoc committee, to feed into the Network was discussed.

Ms. Amy Lickers, Chiefs of Ontario: Ms. Lickers asked if the panelists had ideas for promoting First Nations employment outside of Hydro One. Mr. Doxtator-Young said that, in Hydro One, they had staff that worked on this so this was happening but they wanted to support that through the Network's activities. Mr. Hill noted that they could also develop their own Network webpage to distribute information as well as encouraging more apprenticeships so people will look to Hydro One for training.

Chief Joel Babin, Wahgoshig First Nation: Chief Babin mentioned that he had a number of issues with Hydro One and he was not sure of the timing to bring them up. He felt that one department at Hydro One for Indigenous Relations was not enough; it should be throughout the organization. He felt that they were trying to dictate the relationship with the First Nations.

Councilor Dan Shilling, First Nation Manager, Chippewas of Rama First Nation: Councilor Shilling stated that he wanted to commend the panelists. In terms of First Nations employment in Hydro One, he asked if they had specific targets they would attempt to reach. If they did not set goals, he felt that this could turn into a token project with no real results. Ms. Yoanidis stated that it was difficult as they needed to self-identify as First Nations or Metis. She did not feel it would be a token project as it has been a long time coming; they wanted to increase the current number of 2.3%. They did not have a hard target in mind but wanted to increase that.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): The Chief mentioned that he really enjoyed the presentations and stated that their youth needed to hear these presentations. He also mentioned that when Hydro One staffs come into the communities or territories, they should have a certain number of Indigenous staff with knowledge of the area to deal with any issues. He said that their people could work in their territory and they would be role models seen by the youth. Mr. Doxtator-Young said the Hydro One had their own program such as apprenticeships and it was a difficult process to go through because they had to leave home. He agreed it was not perfect but they had to put their time in and pay their dues. The Chief agreed and said that their youth needed to be aware of the challenges and presentations such as these would have a positive impact.

HYDRO ONE TRANSMISSION AND DISTRIBUTION PLANNING

Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One, provided an overview of his powerpoint presentation entitled "First Nations – Reliability Performance Overview". He provided detailed information on the distribution grid modernization and an overview of the work that will take place in the community.

Chief Edward Wawia, Red Rock Indian Band: The Chief asked about the Ring of Fire Transmission lines and if Hydro One was involved in that. Mr. Jesus responded that they probably were but he was not sure. He said that he could find out. Now confirmed Hydro One is not currently building any transmission lines to supply the Ring of Fire area.

Chief _____________: The Chief stated that coordinating the communications was key within the community when the power goes out; they needed to let their communities know when they can expect the power to come back on. Mr. Jesus stated that they were looking at working with a central coordinating person when the power goes out.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte: The Chief asked about the frequent power outages on his territory and asked if this could be because of defective equipment. Mr. Jesus said that he was note sure because they would have to look specifically at that case but during storms, they do have outages and Hydro One responds as quickly as possible. The Chief then asked what the plans were to address the issues of climate change. Mr. Jesus stated that they had met with the Ministry of Environment and they have established a committee to look at that. He said that the transmission usually performed well but the distribution networks were not as resilient.

Robin Koistinen, Temagami First Nation: Ms. Koistinen said that they wanted to talk about traditional territories and the transmission lines that cross these territories. There were established Indigenous rights and interests in their traditional territories and they need to be aware when work was taking place in these territories. When notifying the First Nation was delayed, the proponents then try to rush through and identify any issues they may have. The First Nations have to be more involved earlier on in the process. It was a concern that the First Nation was not involved when the lines went in and now they were not being consulted on the huge plans for refurbishment. They wanted to identify opportunities for their people in this work and address issues of consultation/accommodation.

Chief Joel Babin, Wahgoshig First Nation: The Chief stated that his First Nation was looking at creative solutions and making their own investments but it was difficult to work with Hydro One to get the upgrades for their systems to supply their needs for economic development. They were trying to grow their community but they ended up waiting for Hydro One. Mr. Jesus said that he wanted to learn what the issues were and suggested they talk off line.

Chief Duke Peltier, Wikwemikong Unceded First Nation: The Chief provided an overview of his community's issue with ongoing and lengthy power outages. In some situation, the weather was very cold and the community members were asking a number of questions around the reliability of their hydro. He suggested that maybe they should look at resourcing support stations for those with ongoing and lengthy outages – warming stations, food for people, supporting those with health issues, etc. The community was large regional centre and he believed that they needed their own substation. They need to talk to Hydro One about this as it very challenging to the community not only residents but business who are attempting economic development initiatives. Mr. Jesus suggested that they need to discuss this.

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

Tabatha Bull, Senior Manager, First Nations and Metis Relations, Independent Electricity System Operator (IESO), provide a brief overview of her powerpoint presentation entitled "Looking Ahead – Opportunities for First Nation Communities through the Implementation of the LTEP". She explained that the government's Long-Term Energy Plan (LTEP) was released on October 26, 2017 along with two directives to the IESO for the completion of an LTEP Implementation Plan by January 31, 2018. The IESO delivered its' implementation plan, *Putting Ontario's Long-Term Energy Plan Into Action*, informed by public engagement, to the Minister on January 31, 2018. The Implementation Plan outlined the objective and scope of each of the directed initiatives to enable LTEP policy objectives and provided key implementation milestones.

Key to their implementation plan was supporting Indigenous capacity and leadership, encouraging an innovative sector and delivering a flexible and efficient system. She then provided an overview of the Energy Support Programs (ESP). She explained that the next steps included: engagement plans would be developed for each initiative; the conservation report and recommendations were nearing completion and the report would be posted publicly; Energy Support Programs (Public Webinar February 22nd at 10:00 am and further engagement on revised programs) and, continued and ongoing engagement with communities.

Chief Joel Babin, Wahgoshig First Nation: The Chief asked a question around the connection costs process that IESO had with Hydro One. Ms. Bull stated that IESO had no authority to change those costs because it was a standard; they could not go outside of that. They could be directed by the Ministry but they could not do this on their own. She added that they were working with communities to identify other sources of funding and mentioned NRCan as a potential source.

OPEN FACILITATED DISCUSSIONS

Participants were given the opportunity to provide their comments:

Tania Jacko, Energy Advisor, Whitefish River First Nation stated that her community appreciated the Delivery Credit, as this brought a lot of relief to many in the community. It was a positive step to building a stronger relationship. There were a lot of good suggestions today; she suggested that the conservation programs should be extended and make them accessible to low and moderate income households. She also encouraged Hydro One to use more Indigenous contractors. Mr. Pugliese stated that they were looking at expanding their affordability funding and also looking at launching pilots for additional home assistance. It was noted that there was more information on the Affordability Fund on the website.

Chief Warren Tabobondung, Wasauksing First Nation, thanked Hydro One for what had been over the last year and also thanked the Chief Committee on Energy for moving their issues forward. He wanted to mention again the transmission lines and distribution network that cut through their traditional territories and this needed to be addressed. These lines had an impact on their traditional land use activities. He stated that he hoped the dialogue tables would continue and he was grateful for the relief that the First Nation Delivery Credit had provided to his community. There was still a lot of work to do.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island) stated that he wanted to see the identification of milestones in their relationship, increased number of Indigenous employees for example, because they needed to be able to evaluate that.

Chief Elaine Johnston, Serpent River First Nation, stated that since she was part of the Chiefs Committee on Energy, she has learned a lot about their energy system and she felt that these dialogues were valuable. Hydro One should have an Indigenous Relations that not only looked at legal issues but also policy issues. They needed to look at land issues and transmission lines. She thanked them for the information that they could share with their communities. She mentioned the priorities areas of the CCOE in terms of expanding the application of the delivery credit.

Robin Koistinen, Temagami First Nation, thanked the CCOE for the work they have done already and she asked Hydro One could not just go ahead and expand delivery credit to band owned buildings, private business on reserve and also off-reserve members. She said that Mr. Pugliese had mentioned that since they changed from being a crown corporation, they had more flexibility. She asked why the province could dictate on that. Mr. Pugliese stated that they still worked in a regulated environment so they had to follow the same rate process involving the Ontario Energy Board; they could make recommendations for a change in policy. The OEB considered what was best for all rate-payers in Ontario. Amy Lickers mentioned that impact of the provincial budget on the delivery credit and stated that this was why they were lobbying around the provincial budget; this will have to be ongoing.

Chief Joel Babin, Wahgoshig First Nation, stated that Hydro One had taken the first step towards developing a meaningful relationship with Fist Nations. However, he felt that there was very little opportunity for participation of First Nation leadership in the agenda for this meeting; they had issues they wanted to discuss and he did not feel that they participated as equal partners in this session. He admitted that there would be some very uncomfortable conversations that need to take place. For the next meeting, he encouraged them to let First Nations state their concerns in their own voice.

Michael Harney, Nipissing First Nation, stated that they were thankful for the delivery credit but he did feel comfortable that this would last over time. There might be changes with a change in government so he wanted to see this strengthened; maybe they needed to look at generating their own electricity and work with the grid to provide that to their communities.

Chief A. Myeengun Henry, Chippewas of the Thames First Nation, asked what caused this change at Hydro One and when funds were made available to programs, where did this come from. Mr. Pugliese stated that he has only been with the company since September 2016; when the company was privatized, a new Board was brought in. There was also a new executive team brought in and the key values focused on communities and customers. There was also a conversation around Indigenous communities because they served many of them. The organizational mandate was changed and they believed it was important to engage with these communities as equal partners. Leveraging opportunities to grow economically was good for everyone. Each board meeting, they discuss Indigenous issues and they have a committee of the Board that worked on this.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte, stated that they were thankful for the delivery credit and the programs but this did not settle past grievances where lands had been taken fraudulently from First Nations. There was no extinguishment of First Nations rights. First Nations want to look at revenue streams and innovative ways to address past grievances. Mr. Pugliese stated that they are open to that and encouraged them to look at the LTEP for other opportunities as well.

Chief Rick Allen, Constance Lake First Nation, asked for clarification around when they could expect a response from Hydro One on negotiating compensation for past grievances. Mr. Pugliese stated that they have to work on those situations on a case by case basis and they were in these conversations now. They were happy to talk about these situations as they arise.

Robin Koistinen, Temagami First Nation, asked that if, in the spirit of an open and transparent relationship, Hydro One could share existing agreements that have been negotiated on compensation for transmission lines. Mr. Pugliese said that they could not share specific details of each community's terms; often the community itself wanted that privacy. He encouraged her that if her community wanted to have this conversation to come talk to them.

WRAP UP

Chief Ava Hill was provided the opportunity to provide closing comments. She said that she too was still learning about energy in order to help the community. She thanked all the presenters and mentioned that she particularly enjoyed the panel presentation of Indigenous employees of Hydro One. She felt that this panel was inspirational; their young people needed to see these examples. She said that they would be looking in more detail at compensation for transmission lines and she appreciated the opportunity to learn more about hydro transmission and distribution today. She said that her community had an agreement that could be shared with others. She said that it was important that they were able to continue these discussions and she liked the format of the session. She suggested that, for future meetings, the Chiefs Committee on Energy could assist with the development of the agenda. The CCOE would be working on pushing the FNDC to include band building in the near future and she suggested that they could meet regularly with Hydro One to continue to strengthen that relationship but also work on finding solutions to address their issues.

Mr. Pugliese said that he could see that their leadership role was a challenging one and stated the importance of not only talking about solutions but acting on those. He said that he welcomed the establishment of a joint group to work on next year's session agenda and they very much looked forward to further strengthening that relationship. They had a more powerful voice when they could work collectively. Increasing ways of tracking the success of their relationship was a good idea and he was confident that they could be the benchmark for success in North America.

A closing prayer was provided by Elder Watson.
Meeting adjourned.

ANNEX A

Hydro One Second Annual First Nations Engagement Session

Chippewas of Rama First Nation, Casino Rama Silvernightingale Room

Goal:	Reinforce working relationships between First Nation communities and Hydro One through continuous engagement and constructive dialogue.
Objectives:	a) Share information on key progress made since February 2017. b) Discuss priorities moving forward in 2018.
Facilitator:	Phil Goulais Advisory & Contract Services
Report Writer:	Carolyn Hunter Hunter-Courchene Consulting Group Inc.
Graphic Recorder:	Disa Kauk, Thinklink Graphics

8:00 – 8:30 **Networking Breakfast (30 minutes)**

8:30 – 8:45 **Opening Prayer from Elder Myrna Watson**

Welcoming Remarks

- Chief Rodney Noganosh Chippewas of Rama First Nation (10 minutes)

8:45 – 9:05 **Opening Remarks**

- Mayor Steve Clarke City of Orillia (10 minutes)
- Chief Ava Hill on behalf of the Chiefs Committee on Energy (10 minutes)

9:05 – 9:20 **Hydro One Address**

- Ferio Pugliese Executive Vice President Customer Care and Corporate Affairs (15 minutes)

9:20 – 9:35 **Round of Introduction** (15 minutes)

9:35 – 10:00 **Hydro One Customer Service**

- Cesar Martinez, Customer Care Manager, Progress on Get Local Initiatives - First Nations Delivery Credit, Ontario Electricity Support Program, Conservation Programing, etc. (15 minutes)
- Qs & As (10 minutes)

10:00 – 10:15 **Health Break and Networking** (15 minutes)

10:15 – 10:45 **Chiefs of Ontario Address**

- Amy Lickers, Director, Economic and Sustainable Community Development: Progress on Ontario First Nations Sovereign Wealth LP (15 minutes)
- Qs & As (15 minutes)

10:45 – 11:30	**Progress on Procurement/Business Partnerships Panel** Facilitator: Susan Wylie Director, Supply Chain Panelists: Darryl Hill, A6N Utilities LP; Bryan Johnston, Aecon-Six Nations Joint Venture; Chief Reginald Niganobe, Mississauga#8 First Nations & Ron Allen, Nigigoonsiminikaaning First Nation (30 minutes) • Qs & As (15 minutes)
11:30 – 12:00	**Hydro One Diversity & Inclusion** • Vivian Yoanidis, Director Diversity & Inclusion: Progress on Diversity & Inclusion Strategy and on Indigenous Leadership Learning Program (10 minutes) • Alicia Sayers, Kevin Hill, Brian George & Charles Doxtater-Young from the Indigenous Network Circle (10 minutes) • Qs & As (10 minutes)
12:00 – 13:00	**Networking Lunch** (60 minutes)
13:00 – 14:00	**Hydro One Transmission and Distribution Planning** • Bruno Jesus, Director, Strategy & Integrated Planning: First Nations Reliability Performance Overview (30 minutes) • Qs & As (30 minutes)
14:00 – 14:45	**Independent Electricity System Operator** • Tabatha Bull, Senior Manager, First Nation and Métis Relations: Progress on key Indigenous energy programs (30 minutes) • Qs & As (15 minutes)
14:45 – 15:30	**Open Facilitated Discussions** • Phil Goulais, Facilitator: *What are Hydro One & First Nations Priorities for 2018?* (45 minutes)
15:30 – 15:45	**Health Break and Networking** (15 minutes)
15:45 – 16:00	**Closing Remarks** • Chief Ava Hill on behalf of the Chiefs Committee on Energy (5 minutes) • Ferio Pugliese Executive Vice President Customer Care and Corporate Affairs (5 minutes) **Closing Prayer from Elder Myrna Watson**
16:00 -17:00	**Networking**
17:00 – 18:00	**Dinner**
18:00 – 19:00	**Mr. Don Burnstick Comedy Show Performance / Networking**

Diversity & Inclusion at Hydro One

Overview

- Diversity & Inclusion Strategy
- Diversity & Inclusion Effectiveness Review
- Indigenous Leadership Training
- Indigenous Network Circle Workshop
- Company Commitments

Diversity & Inclusion Strategy

hydro one

- Organizational benefits of Diversity & Inclusion
  - Higher productivity
  - Safety in the workplace
  - Engagement and trust
  - Better decision making
  - Creativity and innovation

- 3 main goals:
  - To build a diverse workforce
  - Create a culture of inclusion
  - Be a leader in diversity and inclusion in the energy sector.

Diversity & Inclusion Strategy

- We will consider our partners perspectives to help us achieve our goals and deliver them value. Our key partners are:

- Unions
- Customers
- Communities
- Employees & leaders
- Shareholders

5 Paths to Achieving our Strategy

Workforce Planning

- Work with business leaders to identify where diversity and inclusion can enhance their business
- Establish a set of measures that are discussed and actioned with the business

Recruitment

- Develop a recruitment strategy that will attract diverse candidates
- Select diverse candidates and ensure our selection process is not biased

Succession Planning

- Identify and promote diverse candidates

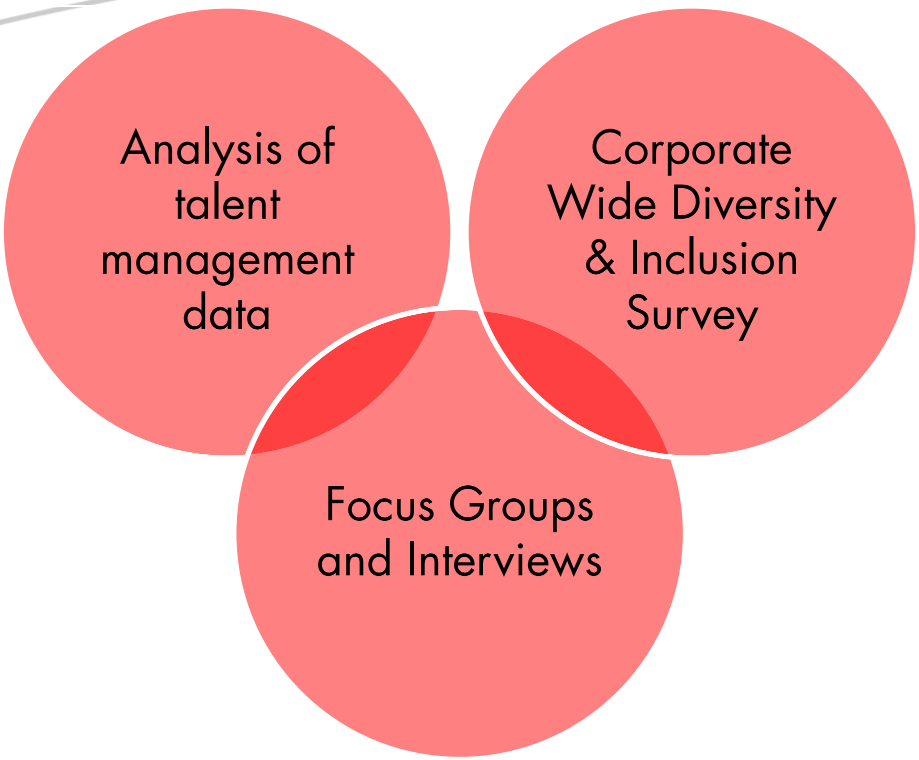
Education and Leadership Development

- Develop a Women in Leadership program
- Roll out Indigenous Leadership Learning program
- Integrate diversity and inclusion principles into training and development programs
- Deliver specialized diversity and inclusion programs

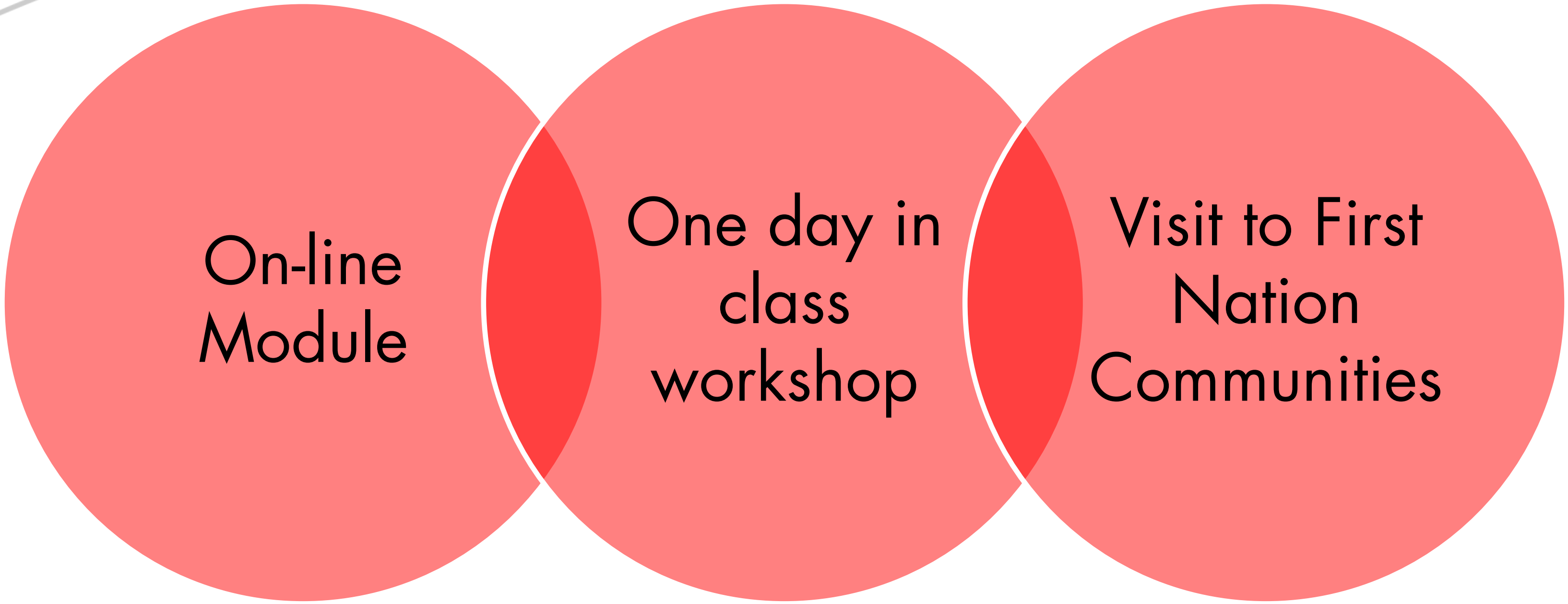
Cultural Guidance and Outreach

- Conduct a diversity and inclusion effectiveness review
- Create and promote employee resource groups including an Indigenous Network Circle
- Develop strategic community partnerships and sponsor community and industry initiatives
- Create a Diversity Leadership Council

Diversity & Inclusion Review



Indigenous Leadership Training



Indigenous Network Circle Workshop

Shared insights and personal experiences

30 Indigenous Employees

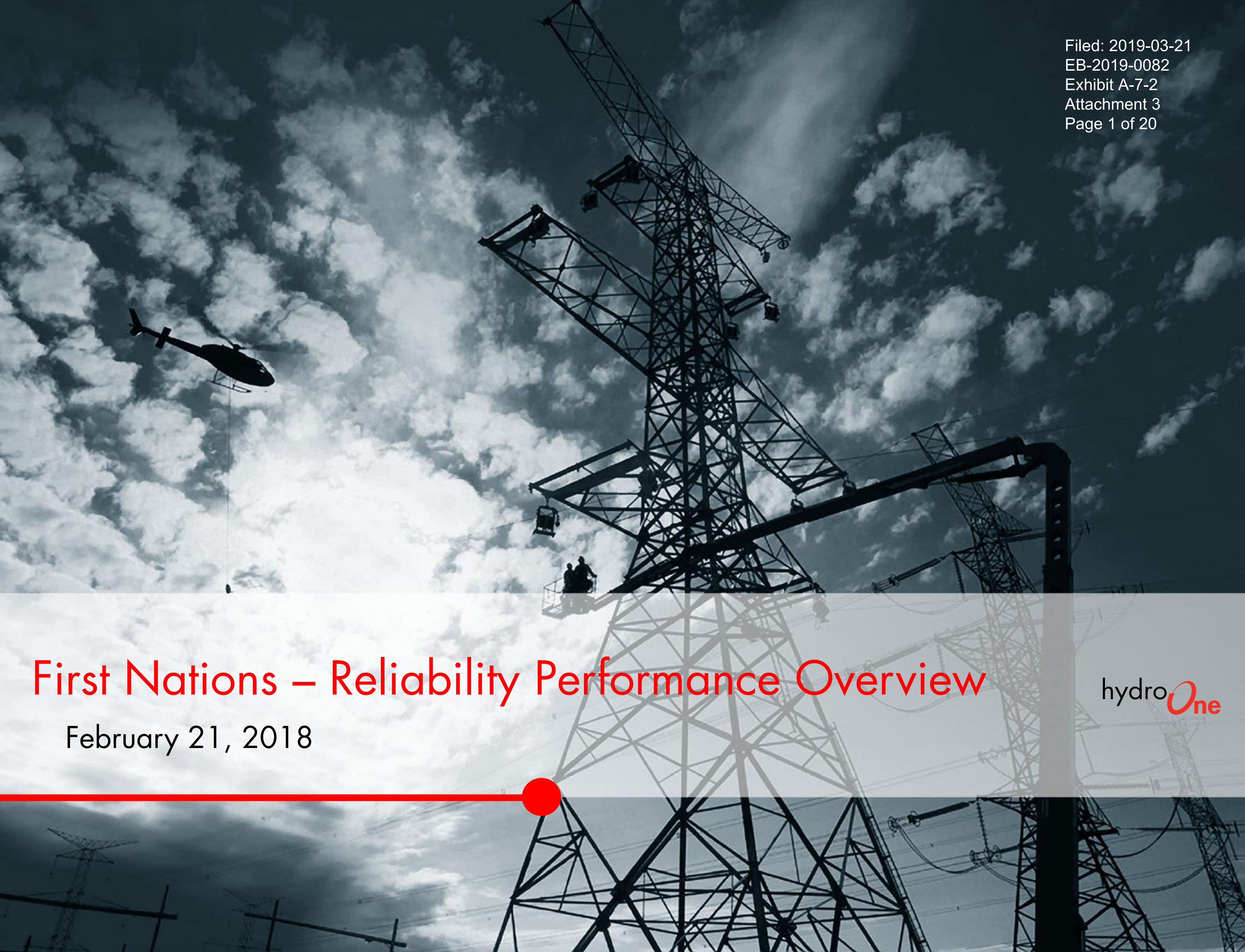
1-day workshop

Unanimously agreed to develop a Network

Company Commitments

- Hire a Diversity & Inclusion Consultant to focus on Indigenous Outreach, Recruitment and Inclusion
- Hire more Indigenous employees:
  - Regular hires
  - Co-op/Internship
  - New Grad
  - Summer Outreach Program
- Visit communities across the province sharing information about recruitment requirements and career opportunities
- Work with Hydro One Indigenous employees to educate and raise cultural awareness within the organization
- Engage Indigenous communities in a dialogue regarding training and development partnerships
- Research and adopt as required Indigenous employment and retention industry best practices

Questions?



First Nations – Reliability Performance Overview

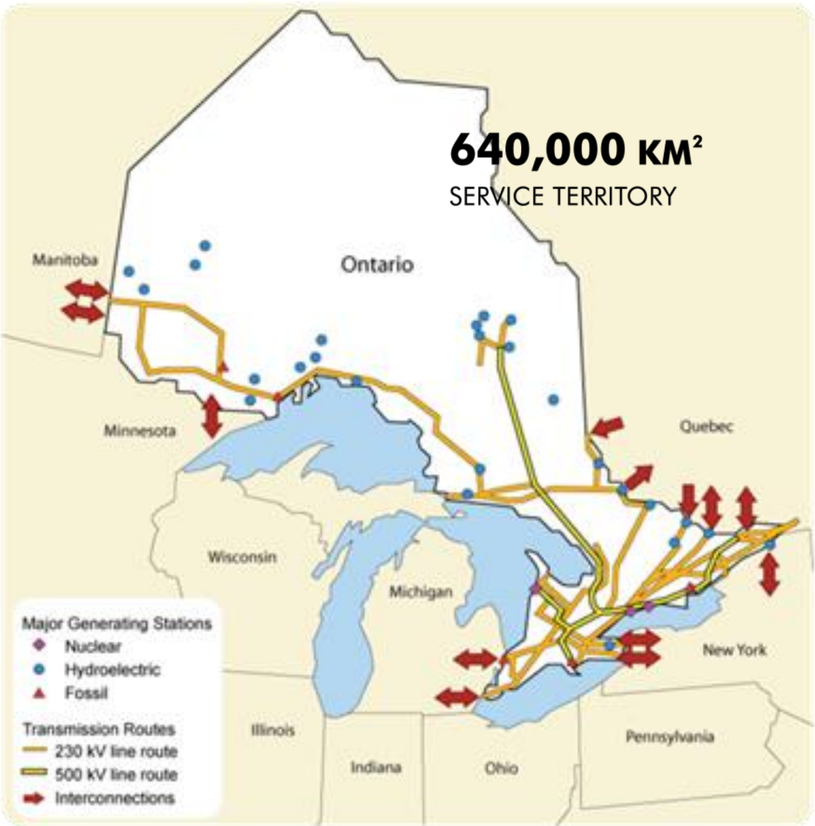
February 21, 2018

hydro One

Agenda

- Hydro One Operations Review
- Historical Reliability Performance
- First Nations Communities Supply
- 2017 Transmission Reliability
- Transmission Reliability Improvements
- 2017 Distribution Reliability
- Distribution Grid Modernization
- Planned Work on Assets Serving First Nations Communities

HYDRO ONE OPERATIONS REVIEW



30,000 KM
OF HIGH-VOLTAGE TRANSMISSION LINES

308
TRANSMISSION STATIONS

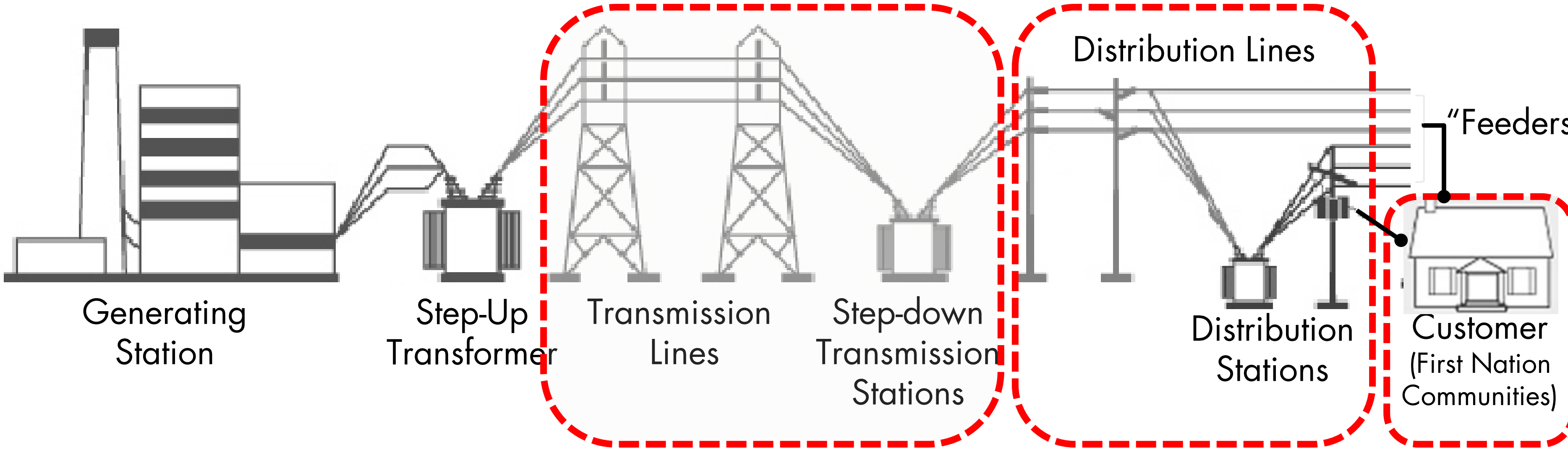
1.6 MILLION
DISTRIBUTION POLES

123,000 KM
OF LOCAL DISTRIBUTION LINES

1.3 MILLION
RESIDENTIAL AND BUSINESS CUSTOMERS ACROSS ONTARIO

1005
Distribution Stations

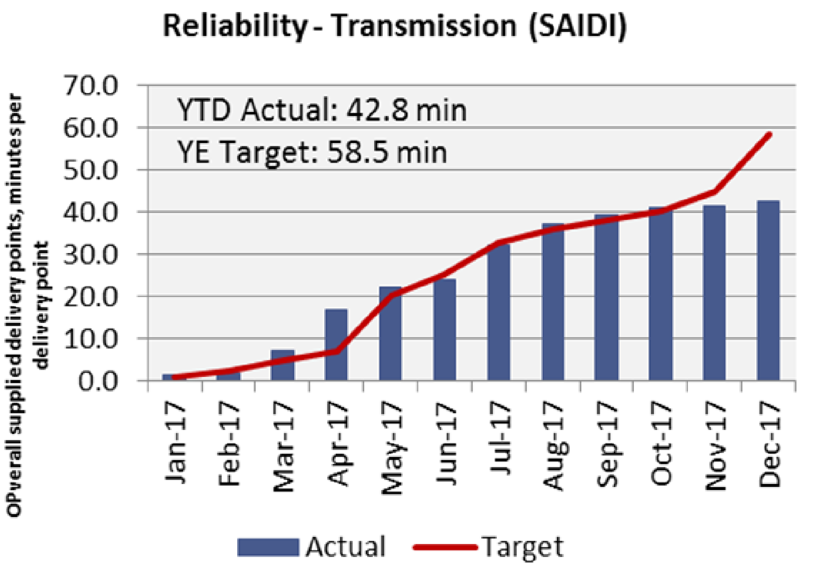
First Nations Communities Supply

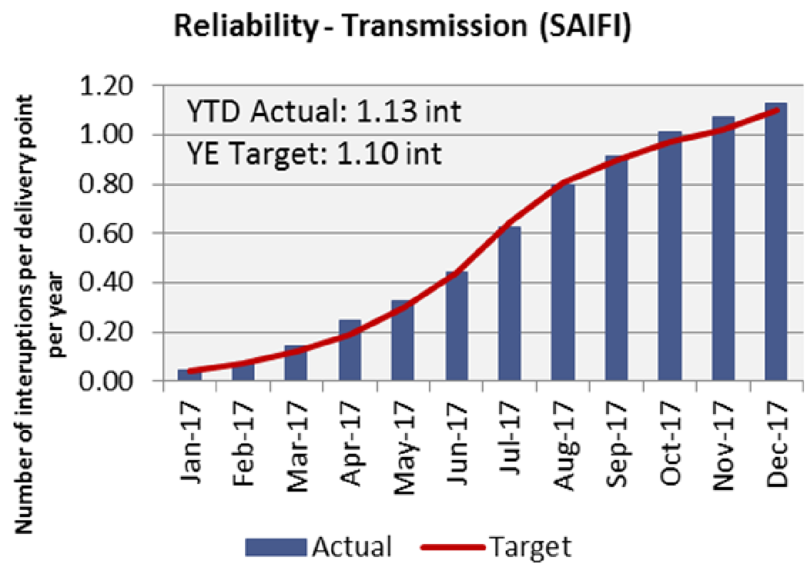


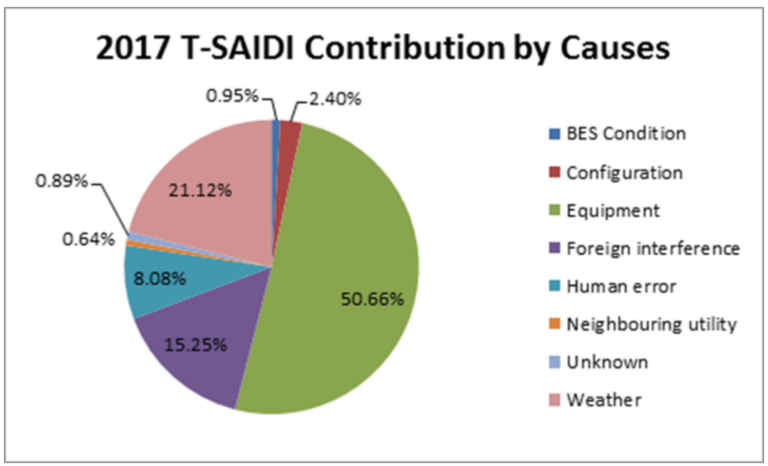
First Nations Communities: Supplied from 68 Transmission Lines, 59 Transmission Delivery Points and 109 Distribution Feeders

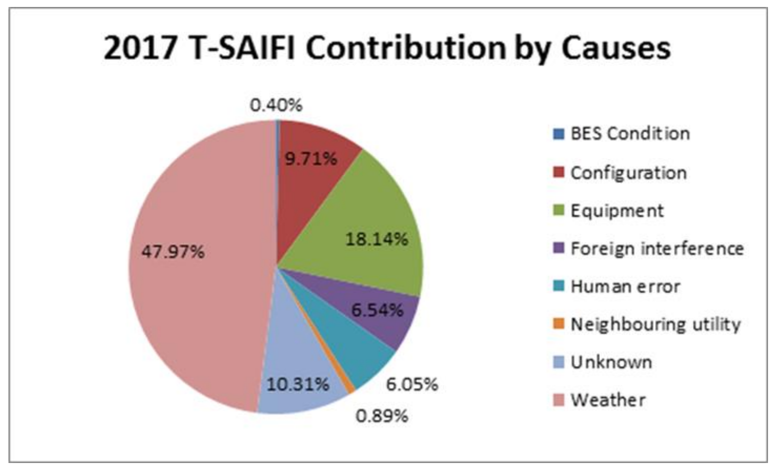
2017 Transmission System Reliability Performance

2017 Year End Overall Transmission Performance: SAIDI was 42.8 min and SAIFI was 1.1 interruptions per customer delivery point. Main causes of these interruptions are 1) Weather 2) Defective Equipment and 3) Unconfirmed







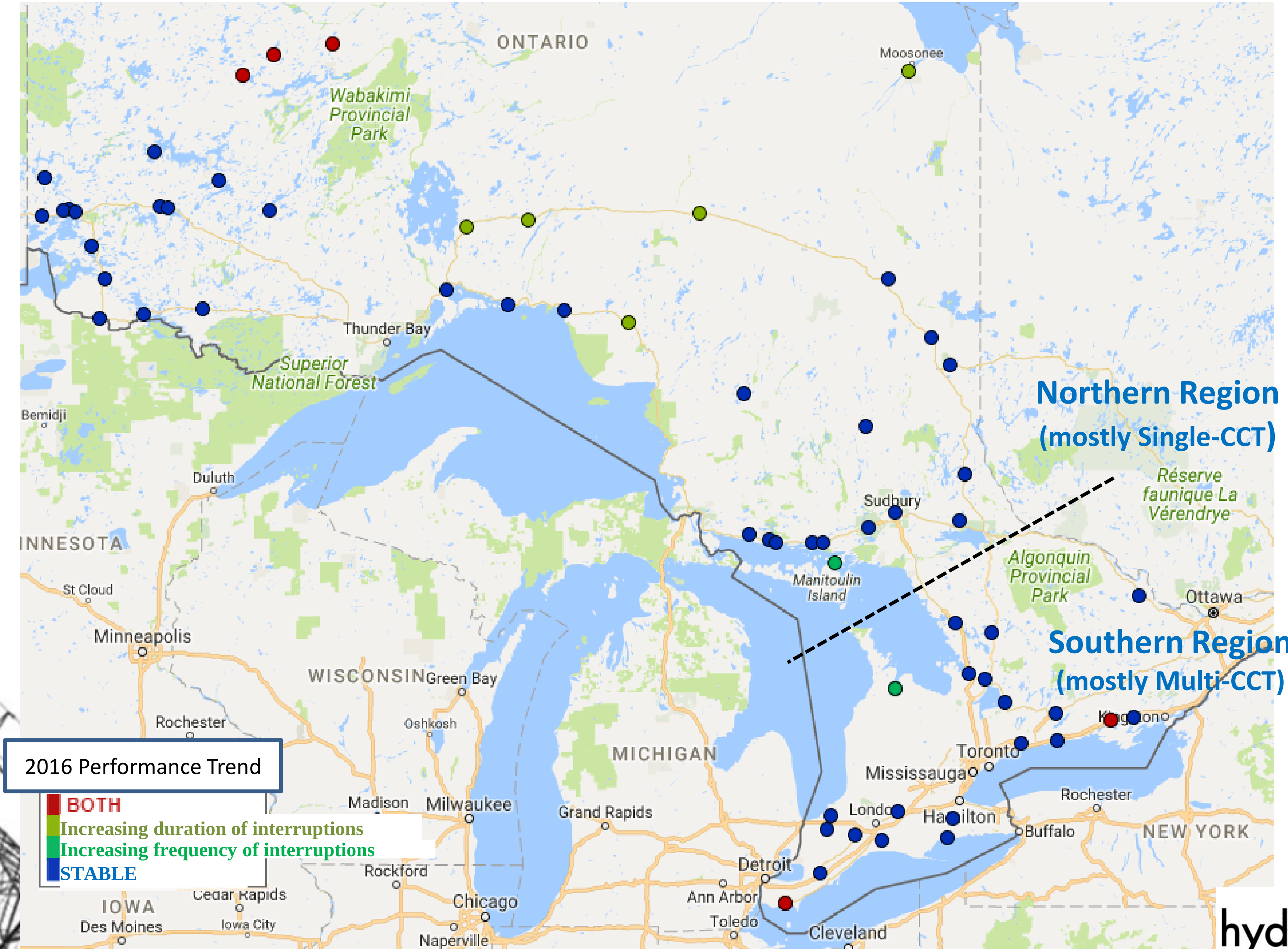


hydroOne

Tx System – Primary Causes of Interruptions:
(~66% from Weather & Equipment Failures)

Power outage causes (2017)		
Weather	**48%**	Adverse weather (freezing rain, ice, lightning)
Equipment failure	**18%**	Majority of failures have occurred on Lines assets (Insulators, Wood Poles, Conductor, etc)
Unconfirmed causes	**10%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Configuration	**10%**	Issues relating to the configuration of the system at the time of the event or system conditions.
Animal/vehicle or Tree Contacts	**7%**	Animal contacts with Hydro One's equipment, motor vehicle or tree-falling events

First Nations: Transmission Connections

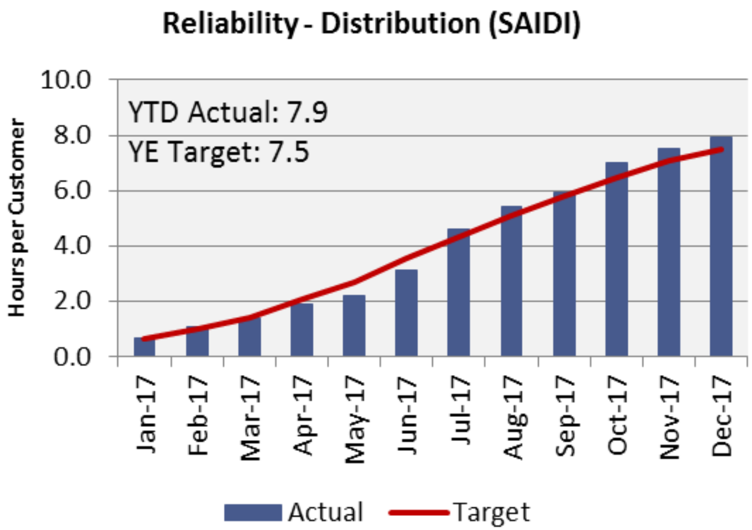


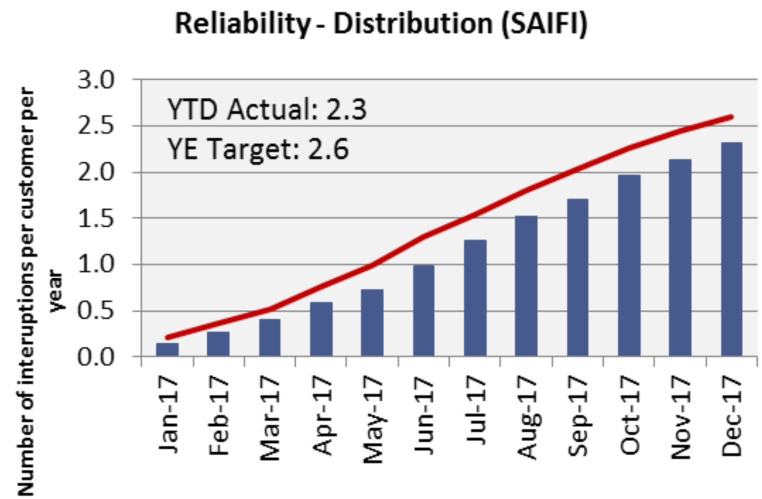
How Is Hydro One Improving Tx Reliability

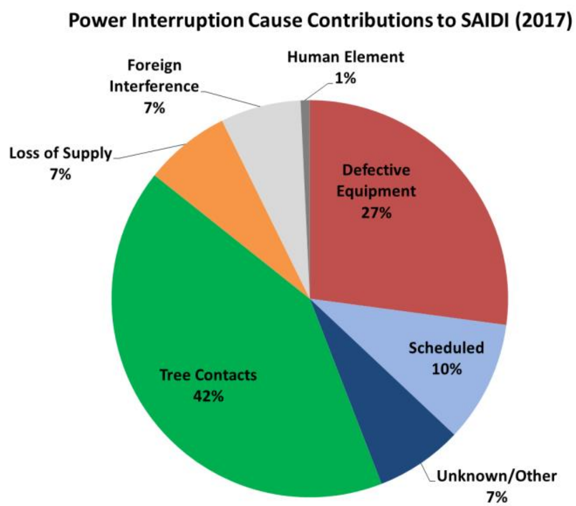
- Increasing Capital Investments (Lines & Stations)
- Address Worst Performing Delivery Points and Transmission Circuits
- Leveraging Technology (Distance-to-Fault)
- Hardening Contingency Plans and Reducing Planned Outages (Bundling Work)

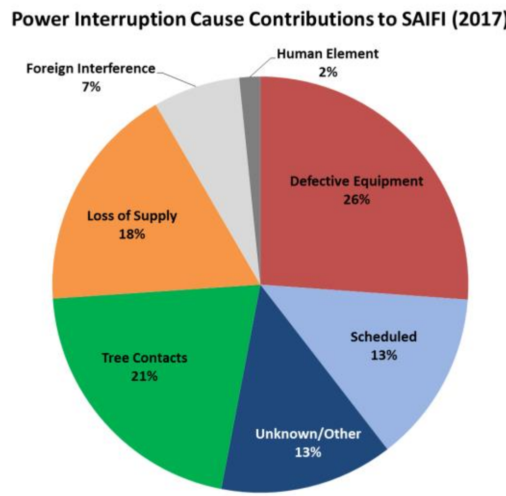
2017 Distribution System Reliability Performance

2017 Year End Overall Distribution Performance: SAIDI was 7.9 hrs and SAIFI was 2.3 interruptions per customer. Main causes of these interruptions are 1) Defective Equipment 2) Tree Contacts 3) Loss of Supply









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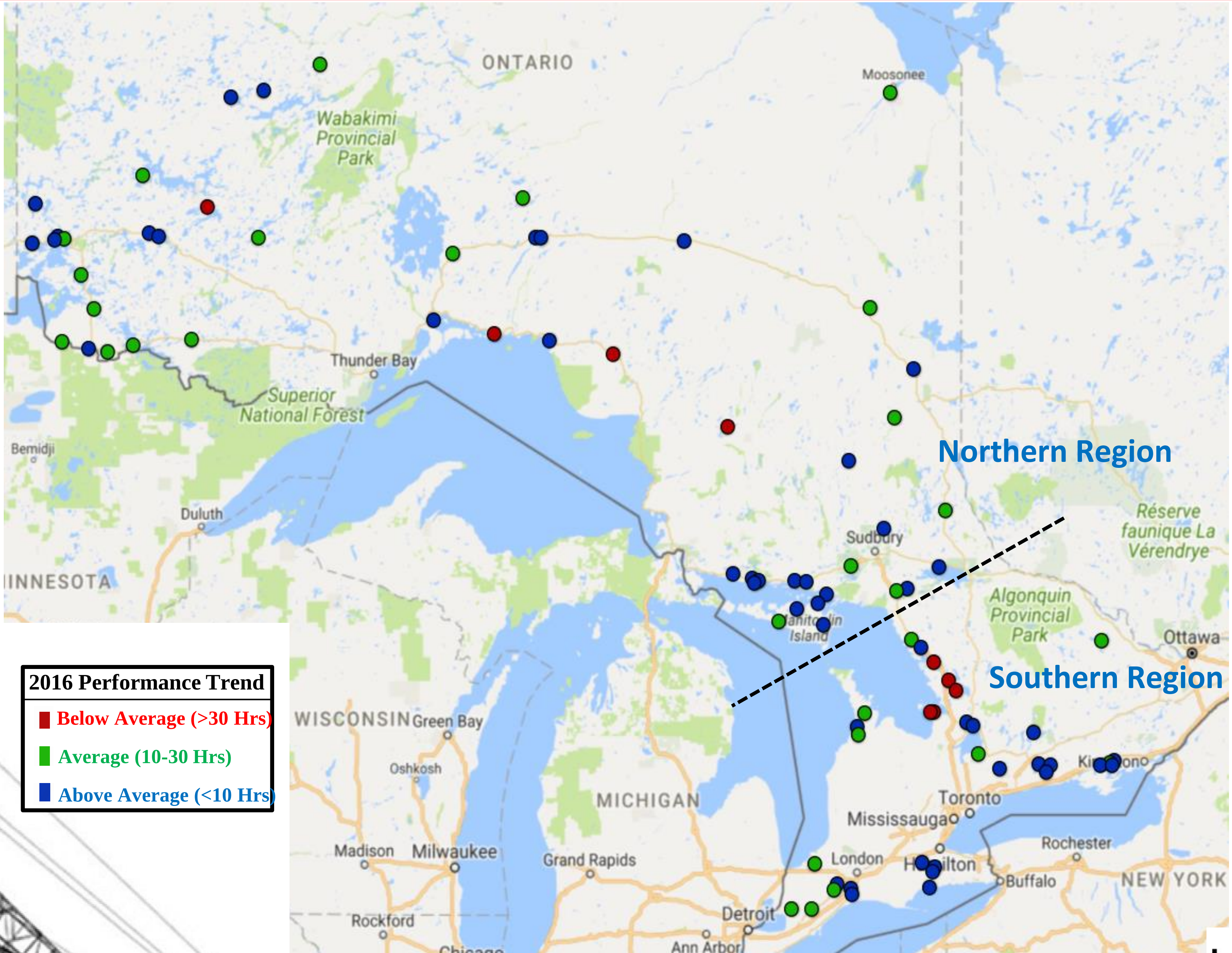
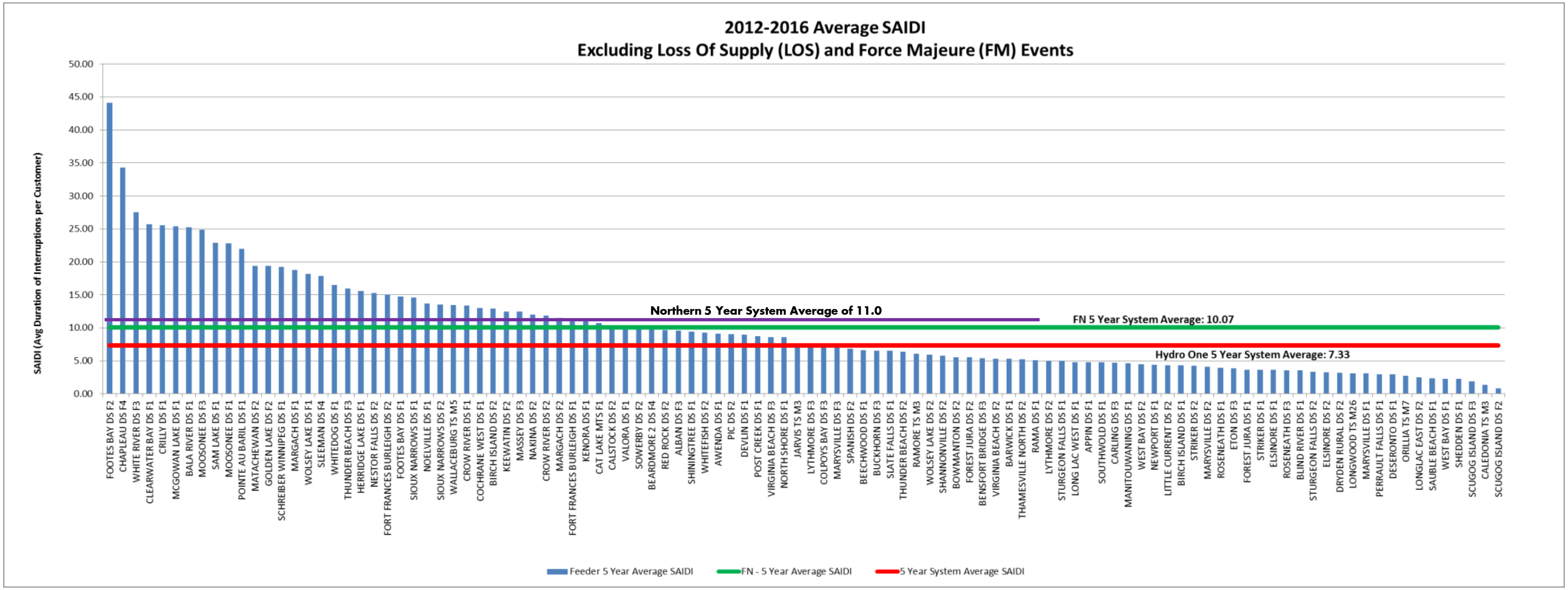
Dx System – Primary Causes of Interruptions:
(~47% occurs from Tree Contacts & Equipment Failures)

Power outage causes (2017)		
Equipment failure	**26%**	Poles, transformers, lines failures can cause an outage.
Tree Contacts	**21%**	Trees fall on lines during storms.
Loss of Supply	**18%**	Transmission caused outage events that result in distribution system loss of supply
Scheduled outages	**13%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Unconfirmed causes	**13%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Animal or vehicle damage to equipment	**7%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.

First Nations: Distribution Connections

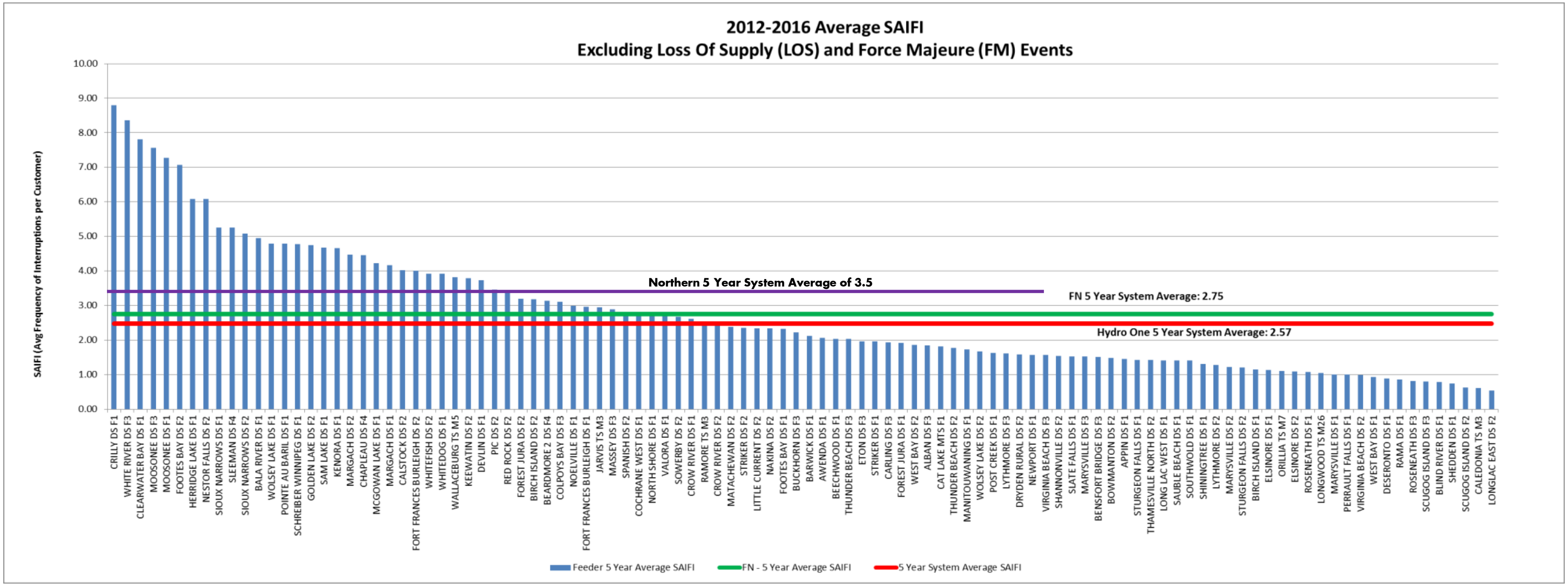


Dx Feeders Supply to First Nations Communities: 5 Year Average SAIDI Excluding Loss of Supply (LOS) and Force Majeure (FM) Events



The First Nations 5 Year average SAIDI performance is about 9% better than the Hydro One Northern system average. The primary SAIDI cause contributor is Tree Contacts. The secondary contributor is Defective Equipment.

Dx Feeders Supply to First Nations Communities: 5 Year Average SAIFI Excluding Loss of Supply (LOS) and Force Majeure (FM) Events



The First Nations 5 year average SAIFI performance is 27% better than the Hydro One Northern system average. The primary SAIFI cause contributor is Tree Contacts. The secondary contributor is Scheduled outages.

DISTRIBUTION GRID MODERNIZATION

Our plan to tackle Distribution Reliability:

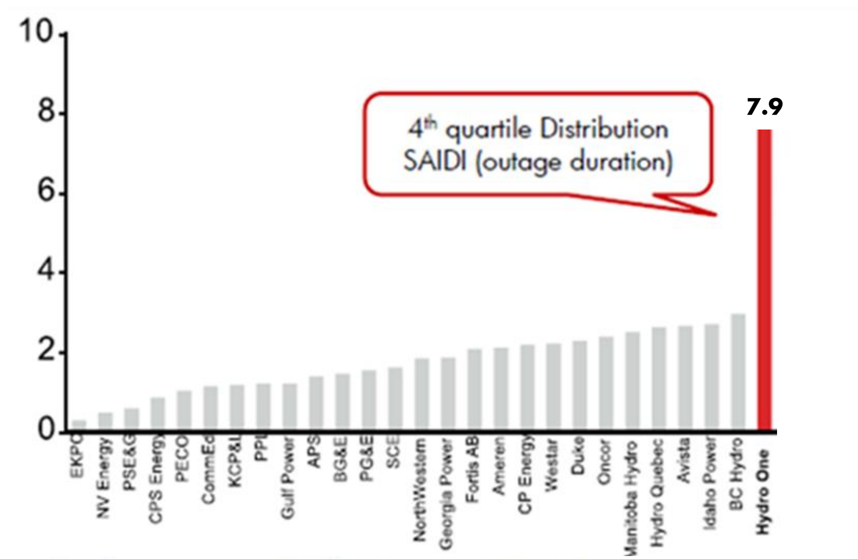
- New vegetation management strategy (20-40% improvement)
- Focusing on 30% worst performing feeders by deploying automation, self-healing, smart sectionalization, fault indicators and remote sensors (20 to 40% improvement)
- Storm prediction tools and processes to improve response and restoration (CAIDI) including leveraging smart meters (10% improvement)
- Grid Modernization and deployment of new technologies (i.e. energy storage, micro grids, electric vehicles) and non-wires solutions for addressing reliability and power quality.

AVERAGE SAIDI FROM 2013 – 2017

7.53

AVERAGE SAIFI FROM 2013 - 2017

2.51



Note: *Peer comparison shows 2016 Hydro One result with 2015 results for peers
Source: EIA 861 data; SNL; Company public disclosures; IEEE

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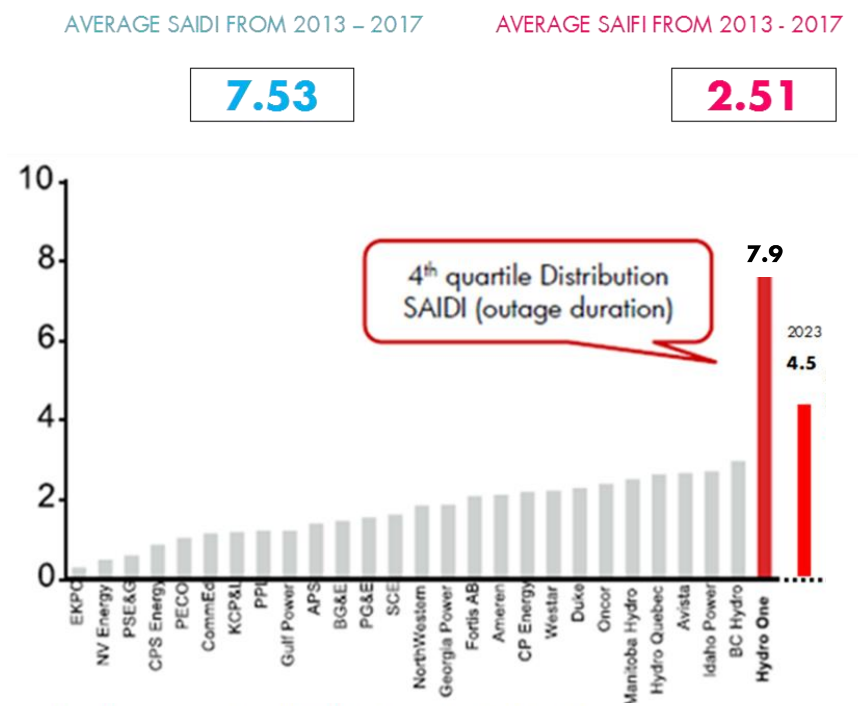

Note: *Peer comparison shows 2016 Hydro One result with 2015 results for peers
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Planned Work on Assets Serving First Nations Communities (Page 1)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Alderville First Nation	3A	Peterboroug	Bowmanton DS	F2	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
	3A		Roseneath DS	F1	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
	3A		Roseneath DS	F3	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
Algonquins of Pikwakanagan	3B	Cobden	Golden Lake DS	F2	COBDEN TS	X2Y / X6	M6	Cobden TS M6 - Install 6 smart switches under worst performing feeder + Tx Line Refurb X2Y	2018 - 19
Animakee Wa Zhing #37	7	Kenora	Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Animbigoo Zaagiigan Anishinaabek (AZA)	7	Thunder Bay	Jellicoe DS #3	F1	Transmission Circuit	A4L		3ph expansion to connect new AZA subdivision + Tx Line Refurbishment	Pending customer signed agreement+ 2021
Anishinaabeg of Naongashiing	7	Fort Frances	Sleeman DS	F4	BARWICK TS	K6F	M2	Sleeman DS Rebuild and voltage conversion to 25 kV	2023
Anishinabe of Wauzhushk Onigum (Rat Portage)	7	Kenora	Margach DS	F1	Transmission Circuit	K6F	K6F	Extend Keewatin DS F2 to pick up portion of Margach DS F1 (Rat Portage FN)	2019
Aroland First Nation	7	Thunder Bay	Nakina DS	F2	LONGLAC TS M2	A4L	A4L	Longlac TS to be relocated (customer driven project) + Tx Line Refurbishment	2021
Asubspeeschoseewagong Netum Anishinabek (Grassy Narrows)	7	Kenora	Margach DS	F2	Transmission Circuit	K6F	K6F		
Aundeck-Omni-Kaning	6	Manitoulin	Little Current DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2018 2017
Beausoloeil First Nation	5	Penetang	Thunder Beach DS	F2	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser.	2018 for switches
	5		Thunder Beach DS	F3	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser.	2018 for switches
	5		Awenda DS	F1	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser. On Awanda DS-F1 we are planning to upgrade the supply to Christian Island	2019 for the upgrades
Big Grassy First Nation	7	Fort Frances	Sleeman DS	F4	BARWICK TS	K6F	M2	Sleeman DS Rebuild and voltage conversion to 25 kV	2023
Biinjitiwaabik Zaaging Anishinaabek (BZA) (aka Rocky Bay First Natior	7	Thunder Bay	Beardmore DS #2	F4	Transmission Circuit	A4L	A4L	Tx Line Refurbishment	
Brunswick House, Chapleau Cree FN , Chapleau Ojibway FN	6	Timmins	Chapleau DS	F4	Transmission Circuit	W2C	W2C		
Caldwell First Nation	1A	Essex	Kingsville TS	-	Kingsville TS	K2Z / K6Z	K2Z	Leamington TS feeder development + New Leamington TS + Kingsville Refurbishment	2018-20
	1A	Essex	Kingsville TS	-	Kingsville TS	K2Z / K6Z	K6Z	Leamington TS feeder development + New Leamington TS + Kingsville Refurbishment	2018-20
Cat Lake FN	7	Dryden	Cat Lake DS	F1	Transmission Circuit	E1C	E1C	Station Refurbishment on site (weather and ice road dependent, was deferred for two years due to warm weather) + Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2018
Chippewas of Georgina Island First Nation	3A	Fenelon Fall	Virginia Beach DS	F2	BEAVERTON TS	M80B / M81B	M27	TS Station Work	2023
	3A		Virginia Beach DS	F3	BEAVERTON TS	M80B / M81B	M27	TS Station Work	2023
Chippewas of Kettle and Stony Point First Nation	1A	Lambton	Forest Jura DS	F1	Transmission Circuit	S2N	S2N	Tx Line Refurb S2N	2019
	1A		Forest Jura DS	F2	Transmission Circuit	S2N	S2N	Tx Line Refurb S2N	2019
Chippewas of Nawash Unceded First Nation	1B	Owen Sound	Colpoys Bay DS	F3	OWEN SOUND TS	B27S / B28S	M23	Mar DS and Feeder Development	2021
Chippewas of Rama First Nation	5	Orillia	Rama DS	F1	ORILLIA TS	M6E / M7E	M7	Sectionalizing M6E/M7E Switches + Tx Line Refurb M6E/M7E + TS station work	2017 - 21
	5		Orillia TS	M7	Transmission Circuit	M6E / M7E	M7E	Sectionalizing M6E/M7E Switches + Tx Line Refurb M6E/M7E + TS station work	2017 - 21
Chippewas of The Thames First Nation	1A	Strathroy	Longwood TS	M26	Transmission Circuit	L24L / L26L	L24L	Longwood TS Station Work	2023
	1A					L24L / L26L	L26L	Longwood TS Station Work	2023
	1A		Appin DS	F1	LONGWOOD TS	L24L / L26L	M26	Longwood TS Station Work	2023

Planned Work on Assets Serving First Nations Communities (Page 2)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Constance Lake First Nation	6	Kapuskasing	Calstock DS	F2	Transmission Circuit	H2N	H2N		
Couchiching First Nation	7	Fort Frances	Burleigh DS	F1	Transmission Circuit	F1B	F1B		
Curve Lake First Nation	3A	Peterboroug	Buckhorn DS	F3	OTONABEE TS DESN2	C28C / H24C	M27	On Otonabee M27, install 3 DMS operable switches and upgrade existing recloser to improve reliability as part of worse performing feeders + Tx Line Refurb C28C	2018 -23
Delaware Nation	1A	Kent	Thamesville North DS	F2	KENT TS DESN2	L28C / L29C	M24	TS Station Refurb	2025
Dokis	6	Sudbury	Noelville DS	F1	MARTINDALE TS	S21N / F2SP	M5	Transformer Replacement Martindale M5 Rebuild + Martindale TS Refurbishment	2018 - 21
Eagle Lake	7	Dryden	Eton DS	F3	Transmission Circuit	K3D	K3D		
Ginoogaming First Nation	7	Thunder Bay	Longlac East DS	F2	LONGLAC TS	A4L	M1	Longlac TS to be relocated (customer driven project) + Tx Line Refurbishment	2021
Henvey Inlet	6	Sudbury	Alban DS	F3	MARTINDALE TS	S21N / F2SP	M5	Wind Farm Connection Martindale M5 Rebuild + Martindale TS Station Refurbishment	2019 2018 - 21
Hiawatha First Nation	3A	Peterboroug	Bensfort Bridge DS	F3	OTONABEE TS DESN2	C28C / H24C	M28	Relocation of Otonabee M28 from off-road to road allowance + Tx Line Refurb C28C	2019 - 23
Iskatewizaagegan #39 Independent First Nation	7	Kenora	Clearwater Bay DS	F1	Transmission Circuit	SK1	SK1		
Lac La Croix	7	Fort Frances	Crilly DS	F1	Transmission Circuit	M1S	M1S	Crilly DS rebuild	2020
Lac Seul First Nation	7	Dryden	Sam Lake DS	F1	Transmission Circuit	K3D	K3D		
Long Lake No. 58 First Nation	7	Thunder Bay	Longlac West DS	F1	LONGLAC TS	A4L	M1	Longlac TS to be relocated (customer driven project)	2021
Magnetawan First Nation	5	Parry Sound	Pointe Au Baril DS	F1	PARRY SOUND TS	E26 / E27	M1	TS Station Work	2022
Matachewan	6	Kirkland Lake	Matachewan DS	F2	KIRKLAND LAKE TS	K2 / A8K	G3K	G3K - Line Relocation + Tx Line Refurbishment A8K & K2 + Kirkland Lake TS Refurbishment	2020 - 23
Mattagami	6	Timmins	Shiningtree DS	F1	Transmission Circuit	T61S	T61S	Worst Performing Feeder Investment + Install Sectionalizing Switch for Shiningtree DS + Tx Line Refurb T61S	2018 -24
M'Chigeeng First Nation	6	Manitoulin	West Bay DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work Worst Performing Feeder Investment	2022 2018
	6		West Bay DS	F2	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2022 2018 2017
Mishkeegogamang	7	Dryden	Crow River DS	F1	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2022
	7		Crow River DS	F2	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2022
Mississauga	6	Algoma	North Shore DS	F1	Transmission Circuit	T1B	T1B		
	6		Blind River DS	F1	STRIKER DS	T1B	F1	Voltage Conversion Project	2021
	6		Striker DS	F1	Transmission Circuit	T1B	T1B		
	6		Striker DS	F2	Transmission Circuit	T1B	T1B		
Mississaugas of Scugog Island First Nation	3A	Bowmanville	Scugog Island DS	F2	WILSON TS DESN2	B23C / E29C	M12	New line build to off load part of M12 to the new Enfield TS + Tx Line Refurbishment B23C + Wilson TS Station Work	2019 - 23
	3A		Scugog Island DS	F3	WILSON TS DESN2	B23C / E29C	M12	New line build to off load part of M12 to the new Enfield TS + Tx Line Refurbishment B23C + Wilson TS Station Work	2019 - 23
Mississaugas of The New Credit First Nation	2	Simcoe	Lythmore DS	F2	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Lythmore DS	F3	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Jarvis TS	M3	Transmission Circuit	N21J / N22J	N21J	New lighting arrestors	2018

Planned Work on Assets Serving First Nations Communities (Page 3)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
MoCreebec Eeyoud aka Moose Cree FN	6	Kapuskasing	Moosonee DS	F1 & F2	Transmission Circuit	M9K / T7M / T8M	M9K	New circuit T8M parallel to T7M was placed I/S in 2015 which will improve performance to Moosonee DS	2015
Mohawks of the Bay of Quinte	3B	Picton	Deseronto DS	F1	NAPANEE TS	X21 / X22	M4		
	3B		Shannonville DS	F2	BELLEVILLE TS	B23C /H23B	M6	Tx Line Refurbishment B23C + TS Station Work	2021 - 23
	3B		Marysville DS	F1	NAPANEE TS	X21 / X22	M4		
	3B		Marysville DS	F2	NAPANEE TS	X21 / X22	M4		
	3B		Marysville DS	F3	NAPANEE TS	X21 / X22	M4		
	3B		Beechwood DS	F1	NAPANEE TS	X21 / X22	M4		
Moose Cree First Nation	6	Kapuskasing	Moosonee DS	F1	Transmission Circuit	M9K / T7M / T8M	M9K	New circuit T8M parallel to T7M was placed I/S in 2015 which will improve performance to Moosonee DS.	2015
	6		Moosonee DS	F3	Transmission Circuit	M9K / T7M / T8M	M9K		
Moose Deer Point First Nation	5	Parry Sound	Footes Bay DS	F2	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
Munsee-Delaware Nation	1A	Strathroy	Appin DS	F1	LONGWOOD TS	L24L / L26L	M26	Longwood TS Station Work	2023
	1A		Longwood TS	M26	Transmission Circuit	L24L / L26L	L26L	Longwood TS Station Work	2023
	1A						L24L	Longwood TS Station Work	
Naicatchewenin	7	Fort Frances	Devlin DS	F1	BARWICK TS	K6F	M1	Devlin DS HV Fuse upgrade, and inline reclosers OCR 906 and 953 upgrade on F1	2018
Naotkamegwanning	7	Kenora	Sioux Narrows DS	F1	Transmission Circuit	K6F	K6F		
	7		Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Nigigoonsiminikaaning First Nation (aka Red Gut First Nation)	7	Fort Frances	Burleigh DS	F2	Transmission Circuit	F1B	F1B	Burleigh DS F2 1ph to 3ph conversion	2020
Nipissing First Nation	6	Nipissing	Sturgeon Falls DS	F1	CRYSTAL FALLS TS	H23S / H24S	M2		
	6		Sturgeon Falls DS	F2	CRYSTAL FALLS TS	H23S / H24S	M2		
Northwest Angle No. 33 / Whitefish Bay 33A	7	Kenora	Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Obashkaandagaang	7	Kenora	Keewatin DS	F2	Transmission Circuit	SK1	SK1	Extend Keewatin DS F2 to pick up portion of Margach DS F1 (Rat Portage FN)	2019
Ochiichagwe'babigo'ining First Nation	7	Kenora	Kenora DS	F1	Transmission Circuit	T1L / T2L	T2L	Station Refurbishment on site	2021
Ojibway Nation of the Saugeen	7	Dryden	Valora DS	F1	Transmission Circuit	29M1	29M1		
Ojibways of Onigaming First Nation	7	Fort Frances	Nestor Falls DS	F2	Transmission Circuit	K6F	K6F		
Oneida Nation of the Thames	1A	Strathroy	Southwold DS	F1	EDGEWARE TS	W44LC / W45LS	M2	Aylmer TS new feeder + Edgeware Station Work	2018 - 21
	1A		Shedden DS	F1	EDGEWARE TS	W44LC / W45LS	M2	Aylmer TS new feeder + Edgeware Station Work	2018 - 21
Pays Plat	7	Thunder Bay	Schreiber Winnipeg D	F1	Transmission Circuit	A5A	A5A	-Schreiber Winnipeg DS Regulator replacement and MUS facility installation -Schreiber town rebuild	2018 -2020
Pic Mobert	7	Thunder Bay	White River DS	F3	Transmission Circuit	M2W	M2W	F1 and F2 station recloser upgrade to Viper, protection coordination update on F1	2018
Pic River First Nation (Biigtigong Nishnaabeg First Nation)	7	Thunder Bay	Pic DS	F2	Transmission Circuit	M2W	M2W		
Rainy River First Nation	7	Fort Frances	Barwick DS	F1	BARWICK TS	K6F	M2		
Red Rock (aka Lake Helen First Nation)	7	Thunder Bay	Red Rock DS	F2	Transmission Circuit	56M1	56M1		
Sagamok Anishnawbek	6	Algoma	Massey DS	F3	Transmission Circuit	S2B	S2B	S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Saugeen First Nation	1B	Owen Sound	Elsinore DS	F1	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018
	1B		Elsinore DS	F2	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018
	1B		Sauble Beach DS	F1	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018

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Planned Work on Assets Serving First Nations Communities (Page 4)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Seine River First Nation	7	Fort Frances	Crilly DS	F1	Transmission Circuit	M1S	M1S	Crilly DS rebuild	2020
Serpent River	6	Algoma	Spanish DS	F2	Transmission Circuit	S2B	S2B	S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Shawanaga First Nation	5	Parry Sound	Carling DS	F3	PARRY SOUND TS	E26 / E27	M1	Carling DS - Nobel Rd & Avro Arrow Rd Line Relocate Pt 1 + TS Station Work	2018 - 22
Sheguiandah	6	Manitoulin	Little Current DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Sheshegwaning	6	Manitoulin	Wolsey Lake DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment	2022
								Worst Performing Feeder Investment	2018
	6		Manitouwaning DS	F1	MANITOULIN TS	S2B	M26	Transformer Replacement	2018
								Worst Performing Feeder Investment	2018
	6		West Bay DS	F2	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work	2022
								Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Shoal Lake No. 40	7	Kenora	Clearwater Bay DS	F1	Transmission Circuit	SK1	SK1		
Six Nations of the Grand River	2	Simcoe	Lythmore DS	F2	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Lythmore DS	F3	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Jarvis TS	M3	Transmission Circuit	N21J / N22J	N21J	New lighting arrestors	2018
	2						N22J	New lighting arrestors	2018
	2		Caledonia TS	M3	Transmission Circuit	N1M / N5M	N5M	Lythmore Relief Project	2018
	2						N1M	Lythmore Relief Project	
	2		Newport DS	F1	BRANTFORD TS	M32W / M33W	M27	Newport DS Conversion	2018
Slate Falls First Nation	7	Dryden	Slate Falls DS	F1	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2020-23
Stanjikoming/Mitaanjigamiing First Nation	7	Fort Frances	Burleigh DS	F1	Transmission Circuit	F1B	F1B		
Taykwa Tagmou Nation	6	Kapuskasing	Cochrane West DS	F1	Transmission Circuit	A4H	A4H	Station Refurbishment + Tx Line Refurbishment	2019 -21
Temagami First Nation	6	New Liskeard	Herridge Lake DS	F1	Transmission Circuit	D2L	D2L	Demand Enhancement - Line Regulator + Tx Line Refurb D2L	2018
Thessalon	6	Algoma	Sowerby DS	F2	Transmission Circuit	T1B	T1B	Station Refurbishment	2019
Wabaseemoong Independent Nations	7	Kenora	Whitedog DS	F1	WHITEDOG FALLS GS	FP3H	FP3H	Station Refurbishment on site	2020
Wabauskang First Nation	7	Dryden	Perrault Falls DS	F1	Transmission Circuit	E4D	E4D	E4D - Upgrade to operate at Higher Temperature	2018
Wabigoon Lake Ojibway Nation	7	Dryden	Dryden Rural DS	F2	DRYDEN TS	FP25A1A2	M1	Dryden TS Station Refurbishment	2018
Wahgoshig	6	Kirkland Lake	Ramore TS	M3	Transmission Circuit	A9K	A9K	Demand Enhancement - Line Regulator	2018
Wahnapitae	6	Sudbury	Post Creek DS	F1	MARTINDALE TS	S21N / F2SP	M7	Martindale TS station refurbishment	2021
Wahta Mohawks First Nation	5	Bracebridge	Bala River DS	F1	MUSKOKA TS	M6E / M7E	M1	Muskoka M1- relocating 10km of line, and installing DMS operable switches + Tx Line Refurb + TS Station Refurbishment	2018 for switches, 201
	5	Parry Sound	Footes Bay DS	F1	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
	5		Footes Bay DS	F2	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
Walpole Island	1A	Kent	Wallaceburg TS	M5	Transmission Circuit	N5K	N5K	N5K - Connect Otter Creek Generation	2019
Wasauksing First Nation	5	Parry Sound	McGowan Lake DS	F1	PARRY SOUND TS	E26 / E27	M3	TS Station Work	2022
Whitefish Lake (Atikameksheng Anishnawbek)	6	Sudbury	Whitefish DS	F2	Transmission Circuit	S2B	S2B	Regulator Replacement	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017

Planned Work on Assets Serving First Nations Communities (Page 5)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Whitefish River	6	Manitoulin	Birch Island DS	F1	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
	6		Birch Island DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Wikwemikong	6	Manitoulin	Manitouwaning DS	F1	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
	6		Wolsey Lake DS	F2	MANITOULIN TS	S2B	M25	Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Zhiibaahaasing First Nation	6	Manitoulin	Wolsey Lake DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment	2022
								Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017

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Customer Programs

Get Local
First Nations
Delivery Credit,
Ontario Electricity
Support Program

2017 By The Numbers

TURN ON THE POWER OF POSSIBILITY

Get Local

- To date, we've visited over 1,500 customers in 35 Communities across the province.

Customers In Arrears

- There has been a reduction of customers in arrears by 2,400 since January 2017, a reduction from 8,900 to 6,500.

First Nations Delivery Credit (FNDC)

- Hydro One launched a blitz in August 2017 to reach out to customers who were not receiving the First Nations Delivery Credit. Since then, we have reduced that number by 1,600 to a total of 4,891. Included in the 4,891 are 2,470 seasonal properties.

Ontario Electricity Support Program (OESP)

- We have doubled OESP enrollments for First Nations customers through our get local efforts from 1,600 to 3,400.

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TURN ON THE POWER OF POSSIBILITY

Top 10 Communities Who Can Benefit from the First Nations Delivery Credit

Below are the number of customers, by Community, that are not currently enrolled in the First Nations Delivery Credit, as well as the number of seasonal properties included in the total.

Community	# Customers Not Enrolled	Seasonal Properties
Saugeen 29FN	1180	1135
Kettle Point 44FN	453	246
Nipissing FN	296	30
Parry Island 16FN	245	209
Christian IS 30FN	243	224
Curve Lake 35FN	227	61
Moose Factory	210	0
West Bay 22FN	194	0
Six Nations 40FN	173	0
Georgina Is 33FN	155	122

*** We need your help in identifying if the accounts classified as seasonal are inhabited by First Nations customers**

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FNDC – Next Steps to 100% Enrollment

TURN ON THE POWER OF POSSIBILITY

Hydro One will be attempting to have 100% enrollment in FNDC by the end of 2018 to ensure all customers are receiving the full benefit of the credit.

<u>How we plan to achieve 100% enrollment</u>

- We need your support! Average customer savings of 50%!
- Increase the number of Get Local Community visits to 60
- Provide detailed maps to Band Offices to help identify seasonal properties and properties not inhabited by First Nations customers
- Door to door visits to meet with customers to assist with the enrollment process
- Social Media campaigns, marketing campaigns (radio, newspaper)

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Benefits of FNDC

TURN ON THE POWER OF POSSIBILITY

Below is an example of a customer's bill pre Fair Hydro Plan and post Fair Hydro Plan for the same time period in 2017 and 2018:

- Feb. 2017 Bill:
  - Consumption: 4,100 kwh
  - Total charges: $650
- Feb. 2018 Bill:
  - Consumption: 6,000 kwh
  - Total charges: $399

- There is a $250 difference between 2017 and 2018 and in the case of this customer, consumption increased by one third from 4,100 kwh to 6,000 kwh

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Get Local 2018

TURN ON THE POWER OF POSSIBILITY

Hydro One plans to continue to grow this program by expanding Get Local from 35 Communities to 60 Communities in 2018.

Has Hydro One been to your Community?

Would you like to schedule a Get Local session in your Community?

We'd love to meet with you!

To request a Get Local session in your Community, please call us at 1-866-994-9909 x 5821 or email us at FNMCustomer@HydroOne.com

- One-on-One meetings with Hydro One and our customers
- Assist with enrollments in FNDC, OESP and other various programs
- Provide dedicated and knowledgeable staff to answer any questions or concerns our customers may have

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TURN ON THE POWER OF POSSIBILITY

Thank You!

DRAFT ISSUES LIST

A. GENERAL

1. Has Hydro One responded appropriately to all relevant Ontario Energy Board ("OEB") directions from previous proceedings?
2. Are all elements of the proposed revenue requirement and their associated total bill impacts reasonable?
3. Were Hydro One's customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?

B. CUSTOM APPLICATION

4. Is Hydro One's proposed Custom Incentive Rate Methodology consistent with the OEB's *Rate Handbook*?
5. Are the proposed industry-specific inflation factor, the proposed custom productivity factor and the proposed capital factor, appropriate?
6. Are the annual updates proposed by Hydro One appropriate?
7. Is the proposed Earnings/Sharing mechanism appropriate?
8. Are the proposed Z-factors and Off-Ramps appropriate?

C. TRANSMISSION SYSTEM PLAN

9. Does the Transmission System Plan adequately address customer needs and preferences?
10. Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of the transmission system assets?

11. Are the proposed Capital Expenditures appropriate?
12. Do the proposed Capital Expenditures include the consideration of factors such as customer preferences, system reliability and asset condition?
13. Are the methodologies used to allocate Common Corporate capital expenditures to the transmission business and to determine the transmission Overhead Capitalization Rate appropriate?
14. Is the benchmarking evidence adequate/sufficient and does it support the proposed Transmission System Plan and related cost forecasts?

D. PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCORECARD

15. Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations?
16. Are the metrics in the proposed scorecard appropriate and do they adequately reflect appropriate outcomes? Do the outcomes adequately reflect customer expectations?

E. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

17. Are the proposed spending levels for Sustainment, Development, Operations, and Customer Care OM&A in 2020 appropriate, including consideration of factors such as system reliability and asset condition?
18. Do the proposed OM&A expenditures include the consideration of factors such as system reliability, asset condition and customer preferences?
19. Are the proposed spending levels for Common Corporate Services and Other OM&A in 2020 appropriate?

20. Are the human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate?
21. Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the transmission business appropriate?
22. Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?
23. Is Hydro One’s proposed depreciation expense appropriate?

F. RATE BASE & COST OF CAPITAL

24. Are the amounts proposed for rate base and capital structure reasonable?
25. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?
26. Is the forecast of long term debt appropriate?

G. LOAD & REVENUE FORECAST

27. Is the load forecast methodology and the resulting load forecast appropriate?
28. Have the impacts of conservation and demand management initiatives been suitably reflected in the forecast?
29. Are Other Revenue (including export revenue) forecasts appropriate?

H. DEFERRAL/VARIANCE ACCOUNTS

30. Are the proposed amounts, disposition and continuance of Hydro One’s existing deferral and variance accounts appropriate?
31. Are the proposed new deferral and variance accounts appropriate?

I. COST ALLOCATION

32. Is the transmission cost allocation proposed by Hydro One appropriate?

J. EXPORT TRANSMISSION SERVICE RATES

33. Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

WITNESS LIST

The list of witnesses will be provided in advance of the oral hearing in this proceeding.

Witness: Frank D'Andrea

CURRICULA VITAE

Curricula Vitae information will be filed prior to the oral hearing.