Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5680
Cell: (416) 568-5534
frank.dandrea@HydroOne.com

Frank D'Andrea
Vice President, Reliability Standards and Chief Regulatory Officer

BY EMAIL AND RESS

August 5, 2021

Ms. Christine E. Long, Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long,

EB-2021-0110 – Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution – Application and Evidence

Attached please find Hydro One Networks Inc.'s (Hydro One) application for:

1. Approval of revenue requirement for Hydro One's transmission business for the period 2023 to 2027; and
2. Approval of rates for Hydro One's distribution business for the period 2023 to 2027 (collectively, the Joint Rate Application or JRAP)

A request for confidential treatment of certain information will be submitted separately.

The JRAP has been submitted electronically using the OEB's Regulatory Electronic Submission System.

Please contact me if you have any questions.

Sincerely,

Frank D'Andrea

Frank D'Andrea

EXHIBIT LIST

Exhibits/attachments denoted by "*" have been provided in Excel format.

Exhibit	Tab	Schedule	Attachment	Contents
A - Administration				
A	1	1		Exhibit List
A	2	1		Application Requests
A	2	1	1	Certification of Evidence
A	2	1	2	Certification Regarding Personal Information
A	2	2		Glossary
A	2	3		Compliance with OEB Filing Requirements for Electricity Transmitters and Distributors
A	2	3	1	Transmission Filing Requirement Checklist*
A	2	3	2	Distribution Filing Requirement Checklist*
A	2	3	3	Hydro One Distribution Updates to Conditions of Service
A	2	4		Summary of Board Directives and Undertakings from Previous Proceedings
A	3	1		Executive Summary
A	3	1	1	Hydro One Networks Inc. Business Plan 2023-2027
A	4	1		Custom IR Application Summary
A	4	1	1	Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application – Clearspring, dated: July 30, 2021
A	4	2		Components of Custom IR Formula - Transmission
A	4	3		Components of Custom IR Formula - Distribution
A	5	1		Corporate Organization Charts
A	5	1	1	Corporate Organizational Structure for the Hydro One Group of Companies
A	5	1	2	Organization Structure - Executive and Senior Management Positions
A	5	2		Pacific Economics Group (PEG) Distribution Total Cost Benchmarking Forecast
A	5	2	1	PEG Benchmarking Forecast Model (Excel Only)*
A	5	3		Distribution Electricity Service Quality Requirements
A	5	3	1	Dx Chapter 2 Appendix 2-G - Service Reliability and Quality Indicators for Distribution*
A	6	1		Accounting Information
A	6	1	1	US GAAP to IFRS Conversion Impact Review – PWC, dated: June 17, 2021

Exhibit	Tab	Schedule	Attachment	Contents	
A	6	2		Hydro One Transmission and Distribution Financial Statements - Historical Years	
A	6	2	1	2018 and 2019 Hydro One Networks Transmission Financial Statements	
A	6	2	2	2019 and 2020 Hydro One Networks Transmission Financial Statements	
A	6	2	3	2018 and 2019 Hydro One Networks Distribution Financial Statements	
A	6	2	4	2019 and 2020 Hydro One Networks Distribution Financial Statements	
A	6	3		Rating Agency Reports	
A	6	3	1	Moody's Investor Service, Credit Opinion, dated: December 21, 2020	
A	6	3	2	S&P Global Ratings Research, dated: March 11, 2021	
A	6	3	3	DBRS Ratings Report, dated: April 21, 2021	
A	6	4		Reconciliation of Regulatory Financial Results with Audited Financial Statements (2020)	
A	6	5		Prospectus for Most Recent Financing	
A	6	5	1	Short Form Base Shelf Prospectus, dated: April 14, 2020	
A	6	6		Hydro One Limited - Historical Year Annual Report (2019 and 2020)	
A	6	6	1	Hydro One Limited 2019 Annual Report	
A	6	6	2	Hydro One Limited 2020 Annual Report	
A	7	1		Identifying Customer Needs	
A	7	1	1	Dx Chapter 2 Appendix 2-AC - Customer Engagement Activities Summary*	
A	7	1	2	Customer Summary	
A	7	2		First Nations and Métis Engagement Strategy	
A	7	2	1	First Nations Reliability Report 2021	
A	8	1		Acquired Distribution and Transmission Utilities	
A	9	1		Draft Issues List	
A	9	2		Witness List	
A	9	3		Curricula Vitae	
B - System Plans					
B-01 System Plan Framework					
B	1	1		Section 1.0	SPF – Introduction to the System Plans Framework
B	1	1		Section 1.1	SPF – System Plans Framework Overview

Exhibit	**Tab**	**Schedule**	**Attachment**	**Contents**	
B	1	1		Section 1.2	SPF – Coordination Through Regional Planning • Attachment 1 – IESO Letter – Regional Planning Process Update • Attachments 2 to 20 – Regional Infrastructure Plans Reports • Attachment 21 – Hydro One Transmission Regional Planning Status Letter to Hydro One Distribution
B	1	1		Section 1.3	SPF – Procurement Process for Third-Party Reports
B	1	1		Section 1.4	SPF - Productivity Framework • Attachment 1 – Hydro One Distribution Productivity Report • Attachment 2 – Hydro One Productivity Framework Review
B	1	1		Section 1.5	SPF – Performance Measurement and Outcomes • Attachment 1 – Performance Reporting Governance Framework
B	1	1		Section 1.6	SPF – Customer Engagement • Attachments 1 to 7 – Customer Engagement Reports
B	1	1		Section 1.7	SPF – Investment Planning Process
B	1	1		Section 1.8	SPF – Climate Change
B-02 Transmission System Plan					
B	2	1		Section 2.0	TSP – Introduction
B	2	1		Section 2.1	TSP – Overview
B	2	1		Section 2.2	TSP – Asset Information and Lifecycle Strategies
B	2	1		Section 2.3	TSP – Benchmarking and Other Studies • Attachments 1 to 4 – Benchmarking and Other Studies

Exhibit	Tab	Schedule	Attachment	Contents	
B	2	1		Section 2.4	TSP – Transmission System Reliability • Attachment 1 – First Nations Reliability Performance • Attachment 2 – Customer Delivery Point Performance Standard • Attachment 3 – Description of the Reliability Measures
B	2	1		Section 2.5	TSP – Performance Measurement and Outcomes • Attachment 1 – Dx Chapter 5 Appendix 5-A – Metrics for Transmission* • Attachment 2 – Dx Chapter 2 Appendix 2-G – Service Reliability and Quality Indicators for Transmission*
B	2	1		Section 2.6	TSP – Other Capital Planning Factors and Considerations
B	2	1		Section 2.7	TSP – Investment Planning Process
B	2	1		Section 2.8	TSP – Capital Expenditures – Overview • Attachment 1 – Dx Chapter 2 Appendix 2-AB - Capital Expenditures for Transmission*
B	2	1		Section 2.9	TSP – Capital Expenditure – Trends and Variances • Attachment 1 – Dx Chapter 2 Appendix 2-AA - Capital Projects for Transmission* • Attachment 2 – Capital Program Performance Report - 2020
B	2	1		Section 2.10	TSP – Capital Work Execution Strategy
B	2	1		Section 2.11	TSP – Material Investments Summary Documents • Investment Summary Documents: T-SA-01 to T-SA-10, T-SR-01 to T-SR-18, T-SS-01 to T-SS-09
B-03 Distribution System Plan					
B	3	1		Section 3.0	DSP – Introduction
B	3	1		Section 3.1	DSP – Overview

Exhibit	Tab	Schedule	Attachment	Contents	
B	4	1		Section 4.3	GSP – Benchmarking and Other Studies • Attachments 1 to 3 – Benchmarking and Other Studies
B	4	1		Section 4.4	Placeholder[1]
B	4	1		Section 4.5	Placeholder[1]
B	4	1		Section 4.6	GSP – Other Capital Planning Factors and Considerations
B	4	1		Section 4.7	GSP – Investment Planning Process
B	4	1		Section 4.8	GSP – Capital Expenditures – Overview • Attachment 1 – Dx Chapter 2 Appendix 2-AB - Capital Expenditures for General Plant*
B	4	1		Section 4.9	GSP – Capital Expenditure – Trends and Variances • Attachment 1 – Dx Chapter 2 Appendix 2-AA - Capital Projects for General Plant* • Attachment 2 – Capital Program Performance Report for General Plant
B	4	1		Section 4.10	GSP - Capital Work Execution Strategy
B	4	1		Section 4.11	GSP - Material Investments Summary Documents • Investment Summary Documents: G-GP-01 to G-GP-22
C - Rate Base					
C	1	1		Rate Base	
C	2	1		Transmission In-Service Additions	
C	2	2		Distribution In-Service Additions	
C	3	1		Shared Asset Allocation	
C	4	1		Statement of Utility Rate Base	
C	4	2		Continuity of Property, Plant and Equipment: Gross Fixed Assets	
C	4	3		Continuity of Property, Plant and Equipment: Accumulated Depreciation	

[1] GSP Sections 4.4 and 4.5 are placeholders to maintain structure alignment with the TSP and DSP.

Exhibit	Tab	Schedule	Attachment	Contents
E	9	2	1	Calculation of Utility Income Taxes – Bridge and Test Years*
E	9	2	2	Calculation of Capital Cost Allowance – Bridge and Test Years*
E	9	2	2A	Reconciliation of Accounting to Tax Additions – Bridge and Test Years*
E	9	2	3	Calculation of Utility Income Taxes - Historical Years*
E	9	2	4	Calculation of Capital Cost Allowance - Historical Years*
E	9	2	5	Calculation of Tax Credits – Bridge and Test Years*
E	9	2	6	Calculation of Tax Credits – Historical Years*
E	9	3		Hydro One Networks Inc. Income Tax Return
E	9	3	1	2020 Tax Return
E	9	4		Taxes Other than Income Taxes
E	10	1		Regulatory Application Costs
E	10	1	1	Dx Chapter 2 Appendix 2-M: Regulatory Cost Schedule*
E	10	2		One Time Costs
E	10	3		Charitable and Political Donations
E	10	4		Z-Factor Claims
F - Cost of Capital and Capital Structure				
F	1	1		Cost of Capital/Capital Structure
F	1	2		Cost of Third Party Long-Term Debt
F	1	3		Debt and Equity Summary*
F	1	4		Cost of Long-Term Debt Capital*
G - Deferral and Variance Accounts				
G	1	1		Regulatory Accounts
G	1	1	1	2020 GA Analysis Workform (Excel Only)*
G	1	1	2	CFO Certification
G	1	1	3	Calculation of the 2018 and 2019 CDM and Demand Response Variance Account
G	1	1	4	Accounting Orders for Utility Specific Accounts Sought for Disposition
G	1	1	5	HONI Transmission and Distribution Accelerated CCA Calculations
G	1	2		Regulatory Accounts Requested
G	1	2	1	Accounting Order - Transmission Capitalized Overhead Tax Variance Account
G	1	2	2	Accounting Order - Transmission Externally Driven Projects Variance Account
G	1	2	3	Accounting Order - Transmission CISVA (Modification)

Exhibit	Tab	Schedule	Attachment	Contents
L	3	1	3	Comparison of LDC OEB Approved Revenue Requirement and Rate Base Following 5-year IRM Applications
L	4	1		Specific Service Charges
L	4	1	1	2021 Specific Service Charges Survey – Innovation Research Group, dated: February 2021
L	4	1	2	Description of Specific Service Charges
L	4	1	3	Proposed Specific Service Charges
L	5	1		Rate Riders
L	5	1	1	Rate Rider for NPDI and WHSI's 1595 (2018) Accounts (Excel Only)*
L	5	1	2	DVA Workform Group 1 (Excel Only)*
L	5	1	3	DVA Workform Group 2 (Excel Only)*
L	5	1	4	Base Rate Adjustment Rider (Excel Only)*
L	6	1		Distribution Bill Impacts and Mitigation
L	6	1	1	2023 Bill Impacts *
L	6	1	2	2024 Bill Impacts *
L	6	1	3	2025 Bill Impacts *
L	6	1	4	2026 Bill Impacts *
L	6	1	5	2027 Bill Impacts *
L	6	2		Loss Factors
L	6	2	1	Dx Chapter 2 Appendix 2-R: Loss Factors *
L	7	1		Current Rate Schedules
L	7	1	1	Current (2021) Tariff Schedules Hydro One Distribution
L	7	1	2	Current (2021) Tariff Schedules Acquired Utilities
L	7	1	3	Current (2021) Tariff Schedules Hydro One Distribution (Excel Only)*
L	7	1	4	Current (2021) Tariff Schedules Norfolk Service Area (Excel Only)*
L	7	1	5	Current (2021) Tariff Schedules Woodstock Service Area (Excel Only)*
L	7	1	6	Current (2021) Tariff Schedules Haldimand Service Area (Excel Only)*
L	7	2		Proposed Rate Schedules
L	7	2	1	2023 Tariff Schedules*

This page left blank intentionally.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Sched. B) (the 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 or fixing just and reasonable rates for the transmission and distribution of electricity.

APPLICATION

1. Hydro One Networks Inc. (Hydro One or the Company) is an Ontario corporation with its head office in Toronto. Hydro One carries on the business, among other things, of owning and operating electricity transmission and distribution facilities in Ontario pursuant to licenses (ET-2003-0035 and ED-2003-0043) from the Ontario Energy Board (the OEB).

2. This is Hydro One's Application for approval of rates under a Custom Incentive Rate-Setting (Custom IR) framework, for a five-year test period commencing January 1, 2023 and ending December 31, 2027, for each of its transmission and distribution businesses. This is Hydro One's first joint rate application and is made pursuant to the OEB's direction.[1]

3. In this Application, Hydro One's transmission business is referred to as Hydro One Transmission, and Hydro One's distribution business is referred to as Hydro One Distribution. Hydro One is an indirect subsidiary of Hydro One Ltd., which is publicly traded on the Toronto Stock Exchange. There are several affiliates of the Company that are

[1] See the March 16, 2018 OEB Correspondence Letter (OEB_letter re HONI Dx and Tx_20180316) for the OEB's expectations regarding future applications for Hydro One distribution rates and transmission revenue requirement, and the July 31, 2019 OEB Correspondence Letter (OEBltr_HONI Remotes_20190731) for the subsequent letter from the OEB agreeing that this application does not need to include Hydro One Remote Communities Inc.

separately regulated by the OEB. Hydro One's corporate structure is shown in Attachment 1 of Exhibit A-05-01.

4. Hydro One's proposed revenue requirement for the 2023 test year has been determined separately for each of the transmission and distribution businesses using a cost of service, forward test year approach. The transmission and distribution revenue requirements for 2024-2027 will be determined formulaically using a proposed Custom IR framework, with parameters specific to each business. For the transmission business, Hydro One requests approval of a revenue requirement and an amendment to Uniform Transmission Rates to allow for recovery of its proposed rates revenue requirement. For the distribution business, Hydro One requests approval of distribution rates and charges, as set out below.

RELIEF SOUGHT

5. Hydro One hereby applies to the OEB for orders approving:

<u>Transmission</u>

a) A total transmission revenue requirement of $1,823.2M for the 2023 test year, to be effective and implemented on January 1, 2023, and an amendment to the Uniform Transmission Rates to allow for recovery of the proposed transmission rates revenue requirement of $1,763.3M for 2023 as further outlined in Exhibit H-01-01;
b) The proposed Custom IR framework, including the applicable transmission-related parameters, to set Hydro One's annual transmission revenue requirement during the period effective January 1, 2024 through December 31, 2027, as described in Exhibits A-04-01 and A-04-02;
c) The proposed charge determinants by rate pool over the test period, as outlined in Exhibit H-07-01;
d) Other Revenues including external revenues and funding for the LV switchgear credit for each of the test years as outlined in Exhibits D-02-01 and H-01-03;
e) Export Transmission Service (ETS) revenues for each of the test years, as described in Exhibit H-09-01;

f) The fees associated with Wholesale Meter Service, as outlined in Exhibit H-08-01;

g) The continuation and discontinuation of Hydro One's current transmission regulatory accounts, as described in Exhibit G-01-02;

h) Accounting orders for new or modified regulatory accounts for Hydro One Transmission, as set out in Exhibit G-01-02;

i) The recovery of transmission regulatory accounts of $5.6M as of December 31, 2020, inclusive of projected carrying charges to December 31, 2022, as outlined in Exhibit G-01-03. Hydro One seeks approval to recover this amount from customers in an addition to its revenue requirement in the amount of $1.1M per year over a five-year period commencing January 1, 2023 as proposed in Exhibit G-01-03; and,

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

Distribution

a) Electricity distribution rates identified in the proposed Tariff of Rates and Charges in Exhibit L-07-02, to be effective January 1, 2023, which are calculated to support Hydro One's 2023 base distribution revenue requirement of $1,586.0M net of external revenue (or total revenue requirement of $1,632.4M) as further outlined in Attachment 1 of Exhibit L-02-01;

b) The proposed Custom IR framework, including applicable distribution-related parameters, to set Hydro One's distribution rates during the period effective January 1, 2024 through December 31, 2027, as described in Exhibits A-04-01 and A-04-03;

c) The proposed Specific Service Charges, as described in Exhibit L-04-01;

d) The continuation and discontinuation of Hydro One's current distribution regulatory accounts, as described in Exhibit G-01-02;

e) Accounting orders for new or modified regulatory accounts for Hydro One Distribution, as set out in Exhibit G-01-02;

f) The refund of distribution regulatory accounts of $87.7M as of December 31, 2020, inclusive of projected carrying charges to December 31, 2022, which include Hydro One

Distribution's Group 1 and 2 balances and Acquired Utilities (Norfolk, Haldimand and Woodstock) Group 1 accounts, as outlined in Exhibit G-01-03. Hydro One seeks approval to refund this amount to ratepayers over a five-year period commencing January 1, 2023 as proposed in Exhibit G-01-03, and approval of the rate riders as proposed in Exhibit L-05-01;

g) The creation of new customer classes as described in Exhibit L-01-02; and,

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

CUSTOMERS AFFECTED

6. Hydro One's transmission and distribution service territories are described in TSP Section 2.1 and DSP Section 3.1, respectively. The persons affected by this Application are Ontario transmission ratepayers and the ratepayers of Hydro One Distribution.

NOTICE AND FORM OF HEARING REQUESTED

7. Given Hydro One's vast transmission and distribution service territories, notice of this Application is recommended to be published by the OEB in newspapers with wide circulation in Ontario, including The Toronto Star, Sudbury Star, Thunder Bay Chronicle Journal, Ottawa Citizen, Hamilton Spectator and Windsor Star. Hydro One also has active social media accounts on Twitter, Facebook, Instagram and LinkedIn platforms.

8. The Application may be viewed on the Internet at the following address: https://www.hydroone.com/about/regulatory

9. Hydro One requests that this Application be heard by way of an oral hearing, consistent with prior proceedings to review Hydro One's multi-year rate applications for Transmission and Distribution.

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

PROPOSED EFFECTIVE DATE

11. Hydro One requests that the OEB's rate orders be effective January 1, 2023.

12. In the event the requested rate orders cannot be made effective by such date, Hydro One requests an Interim Order making its current transmission revenue requirement and charge determinants, as well as its current distribution rates and charges, effective on an interim basis as of January 1, 2023. Hydro One requests the ability to recover any differences between the interim rates and the final rates effective January 1, 2023, based on the OEB's final Decision and Order herein.

BILL IMPACTS

13. *Total bill Impact for typical residential and General Service <50 kW (GSe) customers – Transmission & Distribution*

    For a typical Hydro One medium density residential (R1) customer consuming 750 kWh per month, the estimated total monthly bill impact is a decrease of 0.3% ($0.43) in 2023 resulting from the transmission portion of this Application, and an average annual increase of 0.3% ($0.39) on monthly bills over the Application period.

    Approval of the distribution portion of this Application results in an estimated total monthly bill decrease of 1.8% ($2.78) in 2023 for a typical R1 customer, without Distribution Rate Protection (DRP) per O.Reg 198/17, and an average annual increase of 0.8% ($1.29) on monthly bills over the Application period. With DRP, there is a total monthly bill decrease for the R1 customer of 0.7% ($0.95) in 2023 resulting from the distribution portion of this

Application, and an average annual decrease of 0.1% ($0.19) on monthly bills over the Application period.[2]

For a typical Hydro One General Service <50kW (GSe) customer consuming 2000 kWh per month, the estimated total monthly bill impact is a decrease of 0.2% ($0.90) in 2023 resulting from the transmission portion of this Application, and an average annual increase of 0.2% ($0.83) on monthly bills over the Application period.

Approval of the distribution portion of this Application results in an estimated total monthly bill decrease of 2.0% ($8.32) in 2023 for a typical GSe customer, and an average annual increase of 0.7% ($2.92) on monthly bills over the Application period.[3]

Total Monthly Bill Impact from Transmission Rates	2023	2024	2025	2026	2027
R1 Residential (750 kWh)	($0.43)	$0.49	$0.61	$0.77	$0.52
General Service < 50kW (2000 kWh)	($0.90)	$1.03	$1.30	$1.62	$1.11

Total Monthly Bill Impact from Distribution Rates	2023	2024	2025	2026	2027
R1 Residential (750 kWh) – without DRP	($2.78)	$1.40	$2.36	$3.18	$2.26
General Service < 50kW (2000 kWh)	($8.32)	$1.43	$6.12	$8.38	$6.99

CONDITIONS OF SERVICE

14. Hydro One Distribution's Conditions of Service have changed since its last rebasing application in EB-2017-0049. A summary of key changes and the rationale for the changes are included at Attachment 3 of Exhibit A-02-03. As described in Exhibit L-02-01, this

[2] For distribution only bill impacts for the typical R1 customer, see Exhibit L-06-01.
[3] For distribution only bill impacts for the typical GSe customer, see Exhibit L-06-01.

Application also proposes to remove the requirement for ST customers to own their local transformation, and provide such customers with the option to pay a transformer charge if they meet all of the other requirements of the ST class and prefer to be connected to Hydro One local transformers. If approved, the Conditions of Service will be amended to reflect this new option for customers.

15. There are no rates and charges linked in the Conditions of Service that are not in Hydro One's Tariff of Rates and Charges, except as described in Exhibit L-04-01. The current Conditions of Service can be found on Hydro One's website at: https://www.hydroone.com/about/conditions-of-service

CONFIDENTIAL FILINGS CONTAINED IN APPLICATION

16. Hydro One has not filed any personal information within this Application pursuant to Rule 9A of the *OEB Rules of Practice and Procedure.* A certification regarding personal information has been filed at Attachment 2 of Exhibit A-02-01.

17. Hydro One has filed confidential information pursuant to Rule 10 of the OEB's *Rules of Practice and Procedure.* Hydro One has filed this evidence in accordance with the *Practice Direction on Confidential Filings.*

CONTACT INFORMATION

18. Hydro One requests that copies of all documents filed with or issued by the OEB in connection with this Application be served on Hydro One and its Counsel as follows:

Hydro One:

Ms. Eryn Mackinnon
Senior Regulatory Coordinator
Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5
Tel: 416-345-4373
Fax: 416-345-5395
Regulatory@HydroOne.com

Hydro One's Counsel:

Mr. Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270
TD South Tower
Toronto, Ontario M5K 1N2
Tel: 416-865-7512
ckeizer@torys.com

Mr. Arlen Sternberg
Torys LLP
79 Wellington St. W., 30th Floor
Box 270
TD South Tower
Toronto, Ontario M5K 1N2
Tel: 416-865-8203
asternberg@torys.com

DATED at Toronto, Ontario, this 5th day of August, 2021.

HYDRO ONE NETWORKS INC.

By its Counsel, Torys LLP

Charles Keizer

Arlen Sternberg

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One's Vice President, Reliability Standards and Chief Regulatory 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 *Filing Requirements for Electricity Distribution Applications* (last revised on June 24, 2021); and,
3. The evidence submitted in support of Hydro One's 2023-2027 combined transmission and distribution rate application (EB-2021-0110) is accurate, consistent and complete to the best of my knowledge.

DATED this 5th day of August, 2021.

Frank D'Andrea

____

FRANK D'ANDREA

This page left blank intentionally.

CERTIFICATION REGARDING PERSONAL INFORMATION

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One’s Vice President, Reliability Standards and Chief Regulatory 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 Distribution Applications* (last revised on June 24, 2021); and,
3. The evidence submitted does not contain any personal information filed herein (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB’s *Rules of Practice and Procedure*.

DATED this 5th day of August, 2021.

Frank D'Andrea

____

FRANK D’ANDREA

This page left blank intentionally.

GLOSSARY

"$M" refers to millions of dollars

"Application" refers to this application EB-2021-0110 by Hydro One to the OEB for an order or orders made pursuant to section 78 of the *Act* approving rates for the transmission and distribution of electricity.

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

"C" refers to "custom capital factor".

"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".

"CIR" refers to the "Custom Incentive Rate-setting" option.

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

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

"Distribution Filing Requirements" refers to the OEB's Filing Requirements for Electricity Distribution Rate Applications Chapters 2 and 5 (June 24, 2021).

"DRO" refers to "Draft Rate Order"

"DSC" refers to the "Distribution System Code", which is the OEB document outlining the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems.

"DSP" refers to the "Distribution System Plan", which provides a detailed explanation of Hydro One's proposed capital investment plan for its distribution system in respect of the 5-year planning period from 2023 to 2027.

"Electricity Act" refers to the *Electricity Act, 1998.*

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

"ETS" refers to the "Export Transmission Service".

"FERC" refers to the American "Federal Energy Regulatory Commission".

"GSP" refers to "General Plant System Plan", which presents proposed investments in the General Plant assets and functions that are relied on and shared by the Transmission and Distribution businesses, in respect of the 5-year planning period from 2023 to 2027.

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

"Hydro One Distribution" refers to the distribution business of "Hydro One Networks Inc."

"Hydro One Remotes" refers to "Hydro One Remote Communities Inc.", a subsidiary of Hydro One Inc. that supplies electricity to remote communities in Ontario's far north.

"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 company of Hydro One Ltd. that sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.

"Hydro One Transmission", refers to the transmission business of "Hydro One Networks Inc."

"Hydro One", "HONI" or the "Company" refers to the transmission and distribution 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.

"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.

"IESO" refers to the "Independent Electricity Systems Operator".

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

"INPO" refers to the "Institute of Nuclear Power Operations".

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

"IR" refers to "Incentive Rate-Setting".

"ISD" refers to "Investment Summary Documents", which detail specifics for each material capital investment with spending greater than $3M in any one year for Hydro One Transmission or $1M in any one year for Hydro One Distribution.

"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.

"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.

"MACD" refers to the "Market Assessment and Compliance Division", a ring-fenced business unit of the IESO that performs monitoring and enforcement of Market Participants' compliance including compliance with applicable reliability standards.

"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.

"Niagara Reinforcement LP" refers to "Niagara Reinforcement Limited Partnership" which owns and operates the transmission facilities related to the Niagara Reinforcement Project in southwestern Ontario.

"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".

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

"OEB" 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.

"OM&A" refers to "Operations, Maintenance and Administration".

"OPEBs" refers to "Other Post-Employment Benefit Costs".

"OPG" refers to "Ontario Power Generation".

"PILs" refers to "Payment in Lieu of Taxes".

“Planning period” refers to the five year period from 2023 to 2027 for which Hydro One’s Application is requesting approval of its transmission and distribution revenue requirements.

“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”.

“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.

“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”.

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

"TFP" refers to "total factor productivity".

"Transmission Filing Requirements" refers to the OEB's Chapter 2 (Revenue Requirement Applications) of the Ontario Energy Board's Filing Requirements for Electricity Transmission Applications, issued on February 11, 2016, with further guidance from Chapter 5 of the Filing Requirements (Consolidated Distribution System Plan Filing Requirements), issued on June 24, 2021.

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

"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 2023 to 2027.

"UCC" refers to "undepreciated capital costs."

"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".

"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.

This page left blank intentionally.

COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY TRANSMITTERS AND DISTRIBUTORS

1.0 OVERVIEW OF FILING REQUIREMENTS

The Filing Requirements for Electricity Transmission and Distribution Rate Applications have been developed by the OEB to ensure that a utility's rate application contains complete and consistent information to justify its proposed rates. The Filing Requirements are underpinned by the principles of the renewed regulatory framework (RRF) articulated in the *Handbook to Utility Rate Applications* (Handbook) dated October 13, 2016. The Handbook and Filing Requirements have guided the development of Hydro One's evidence for this Application.

2.0 COMPLIANCE WITH FILING REQUIREMENTS

Hydro One has prepared its evidence in accordance with the *Chapter 2 Filing Requirements for Electricity Transmission Rate Applications* (February 11, 2016) (Transmission Filing Requirements) and *Chapters 2 and 5 Filing Requirements for Electricity Distribution Applications* (June 24, 2021) (Distribution Filing Requirements). Hydro One has complied with the OEB's policies and expectations contained in the filing requirements and filed a certification on the accuracy of the evidence at Attachment 1 of Exhibit A-02-01.

Attachment 1 of this exhibit includes a checklist based on the Transmission Filing Requirements dated February 11, 2016, which Hydro One produced to demonstrate completeness of the Transmission component of its Application. Hydro One completed the 2022 cost of service checklist for the Distribution Filing Requirements issued by the OEB on June 28, 2021 for the Distribution component of its Application, filed at Attachment 2 of this exhibit. Hydro One also created a Table of Concordance in TSP Section 2.0 Appendix A and DSP Section 3.0 Appendix A to map all TSP and DSP filing requirements, respectively, to the System Plans evidence. Attachment 3 of this exhibit includes a summary of changes in the Conditions of Service since the last Distribution rate application was filed.

In this Application, Hydro One used the OEB's models to prepare its evidence, which include but are not limited to the following:

- OEB's Revenue Requirement Workform (RRWF) (Tabs 1 to 9) for Hydro One Transmission and Distribution, filed at Attachments 1 to 10 of Exhibit D-01-01. Moreover, Tab 12 of RRWF is filed at Attachment 2 of Exhibit L-02-01. Tab 13 of RRWF is filed at Attachment 1 and Attachment 3 of Exhibit L-02-01, respectively;[1]
- OEB's Chapter 2 Appendices for Hydro One Transmission and Distribution filed with the related exhibits of the evidence, with exceptions noted in the filing requirement checklists therein (Attachments 1 and 2 of this exhibit). Most tabs were modified to include the 2022 and 2023 test year data;
- PEG Benchmarking Model at Attachment 1 of Exhibit A-05-02;
- OEB's Cost Allocation Model for Hydro One Distribution, filed at Attachment 1 of Exhibit L-01-03;
- OEB's Deferral and Variance Account Continuity Schedules for Hydro One Transmission and Distribution (including Acquired Utilities), filed at Attachments 1 to 3 of Exhibit G-01-05, with certain tabs filed as separate attachments to calculate:
    - Derivation of Group 1 DVA Rate Riders, filed at Attachment 2 of Exhibit L-05-01;
    - Derivation of rate riders for Account 1595 (2018) for Norfolk and Woodstock service areas, filed at Attachment 1 of Exhibit L-05-01;
    - Derivation of Group 2 DVA Rate Riders, filed at Attachment 3 of Exhibit L-05-01;
- Global Adjustment (GA) Analysis Workform, filed at Attachment 1 of Exhibit G-01-01; and,
- 1595 Analysis Workforms, filed at Attachments 1 and 2 of Exhibit G-01-03.

[1] Exhibit D-05-01-02 is used in place of Tab 10 and in regards to Tab 11 of the workform, the template does not allow the flexibility needed for Hydro One's cost allocation and rate design requirements. Information equivalent to that requested in the workform is provided in Exhibit L-01-03 and L-02-01.

In addition, Hydro One has created custom excel models that are filed with the following exhibits, including the following excel models noted below:

- Custom income tax calculation spreadsheets for Hydro One Transmission and Distribution, in lieu of using the OEB's PILS workform, filed at Attachments 1 to 6 of Exhibit E-09-02;
- Custom[2] bill impacts model for Hydro One Distribution, in lieu of using the OEB's Tariff Schedule and Bill Impacts Model, filed at Attachments 1 to 5 of Exhibit L-06-01;
- Custom[3] tariff schedules, in lieu of using the OEB's Tariff Schedule and Bill Impacts Model, filed at Attachment 1 of Exhibit L-07-01; and,
- Custom[4] Retail Transmission Services Rates (RTSR) model for Hydro One Distribution, in lieu of using the OEB's RTSR Workform, filed at Attachment 5 of Exhibit L-02-01.

Hydro One has filed its data in the OEB's workforms in live Microsoft Excel format and ensured that the data reconciles between the models.

Hydro One has addressed the directions of the OEB from its decisions in the 2020-2022 Transmission and 2018-2022 Distribution proceedings (see Exhibit A-02-04).

---

[2] Hydro One's bill impact model is consistent with the requirements of the OEB's Bill Impacts Model, and the bill impact sheets for all rate classes in all years are provided in as Attachments 1 to 5 in Exhibit L-06-01. Hydro One has used this format for bill impacts in all prior applications.

[3] Hydro One's tariff schedules align with the OEB's Tariff Schedule and Bill Impacts Model.

[4] Hydro One does not calculate RTSRs per the OEB's RTSR Workform as noted in Exhibit L-02-01, section 8.3. Rather, Hydro One uses the methodology that has been reviewed and approved by the OEB for Hydro One's distribution rate filings since 2008, which more accurately reflects the share of transmission charges incurred by each class.

3.0 COMPLIANCE WITH CUSTOM IR FRAMEWORK EXPECTATIONS

Hydro One's Custom IR Application includes the following key components which align with the expectations for a custom IR framework set out in the Handbook:

1. Term: Hydro One's custom IR term for Transmission and Distribution are both over a 5-year term, from 2023-2027, consistent with the guidance in the Handbook.

2. Index for the Annual Rate Adjustment: The proposed Revenue Cap Index includes specific financial incentives for continuous improvement through a custom productivity factor for Transmission and Distribution that is supported by third-party empirical evidence (including a supplemental stretch factor on capital). See Exhibits A-04-01, A-04-02, and A-04-03.

3. Benchmarking: Hydro One's combined transmission and distribution application is supported by an extensive number of benchmarking studies along with reviews of processes, asset condition analyses and lifecycle studies, to address prior OEB directions from the prior rebasing applications. See SPF Section 1.3 for details on third party studies filed with this Application.

4. Performance Metrics: Hydro One has proposed evolved transmission and distribution scorecards in TSP Section 2.5 and DSP Section 3.5. The proposed metrics align with the RRF outcomes of customer focus, operational effectiveness, financial performance, and public policy responsiveness. The proposed targets demonstrate Hydro One's commitment to continuous improvement.

5. Updates: Hydro One's proposal contains updates limited to those described in Exhibits A-04-02 and A-04-03 for Transmission and Distribution, respectively.

6. Protecting Customers: Hydro One continues to propose an Earnings Sharing Mechanism and Capital In-Service Variance Accounts for both Transmission and Distribution. This will enable the sharing of the benefits of productivity improvements with customers during the plan term and provide ratepayers with protection from utility earnings that become excessive, see Exhibit A-04-01.

3.1 MATERIALITY THRESHOLDS

In terms of the materiality used by Hydro One Networks, the following thresholds apply:

- $1M for Hydro One Distribution, as defined in section 2.0.8 of the Chapter 2 Filing Requirement for Electricity Distributors, applicable to distributors with a revenue requirement of more than $200M; and
- $3M for Hydro One Transmission, as defined in section 2.1.1 of the Chapter 2 Filing Requirement for Electricity Transmitters, applicable to transmitters with a revenue requirement of more than $200M.

3.2 FILING OF COMPREHENSIVE SYSTEM PLANS

As this is Hydro One's first combined transmission and distribution rate application submitted before the OEB, Hydro One has filed comprehensive system plans in support of its capital needs, including a TSP, DSP, SPF and GSP. Hydro One adopted the Chapter 5 Filing Requirements to guide the content and structure of its TSP,[5] SPF and GSP to ensure that all the considerations for a DSP filing are included in the design of its system plans.

3.3 CUSTOMER ENGAGEMENT PROCESS

Hydro One's plans reflect customer needs and preferences, which were identified through a comprehensive two-phase customer engagement process, as detailed in SPF Section 1.6. Hydro One's investment planning, business planning, regulatory process and customer engagement

[5] Section 2.4 of Chapter 2 Transmission Filing Requirement noting that transmitters can refer to Chapter 5 of the OEB's *Filing Requirements for Electricity Distributors, Consolidated Distribution System Plan Filing Requirements* (DSP Filing Requirements)

process were fully integrated, allowing Hydro One to develop System Plans that are truly responsive to customer needs.

4.0 HOST & EMBEDDED DISTRIBUTOR FILING REQUIREMENTS

Hydro One is both a host distributor and a partially embedded distributor.

Hydro One is partially embedded in Alectra Utilities Corporation, Canadian Niagara Power, ELK Energy, Energy+ Inc., ERTH Power Corporation, Essex Power Lines, Halton Hills Hydro, Hydro Ottawa, InnPower Corporation, Lakeland Power Distribution, Milton Hydro, Newmarket-Tay Power Distribution Ltd., Niagara Peninsula Energy, North Bay Hydro, Elexicon Energy Inc., Waterloo North Hydro, and Westario Power Inc.

Approximately 1% of customer load is supplied through host distributors.

Hydro One is a host distributor for Alectra Utilities Corporation, Bluewater Power Distribution Corporation, Canadian Niagara Power Inc., Centre Wellington Hydro Ltd., Chapleau Public Utilities Corporation, EPCOR Electricity Distribution Ontario Inc., Cooperative Hydro Embrun Inc., E.L.K. Energy Inc., Eastern Ontario Power Inc., Energy+ Inc., Entegrus Powerlines lnc., ERTH Power Corporation, Espanola Regional Hydro Distribution Corp., Essex Powerlines Corporation, Festival Hydro Inc., Greater Sudbury Hydro Inc., Grimsby Power Inc., Halton Hills Hydro Inc., Hearst Power Distribution Company Limited, Hydro 2000 Inc., Hydro Hawkesbury Inc., Hydro Ottawa Limited, InnPower Corporation, Kingston Hydro Corporation, Lakefront Utilities Inc., Lakeland Power Distribution Ltd., London Hydro Inc., Milton Hydro Distribution Inc., Newmarket-Tay Power Distribution Ltd., Niagara Peninsula Energy Inc., North Bay Hydro Distribution Ltd., Northern Ontario Wires Inc., Oakville Hydro Electricity Distribution Inc., Orangeville Hydro Limited, Ottawa River Power Corporation, Renfrew Hydro Inc., Rideau St. Lawrence Distribution Inc., Sioux Lookout Hydro Inc., Toronto Hydro-Electric System Limited, Elexicon Energy Inc., Wasaga Distribution Inc., Wataynikaneyap Power LP, Waterloo North Hydro Inc., Wellington North Power Inc, and Westario Power Inc.

Exhibit L-01-02 describes Hydro One's sub-transmission (ST) rate class. The ST rate class applies to all distributors embedded in Hydro One's distribution system.

Embedded distributors were engaged as part of Hydro One's customer engagement described in SPF Section 1.6. As detailed in Exhibit L-02-01, section 5.2, the methodology used for the allocation of costs to the ST rate class, as well as the design of ST rates, has not changed from the methodology that was used in Hydro One's previous distribution rate applications. Hydro One has had approved ST rates applicable to its embedded distributors since 2008. As such, a statement of support for embedded distributor cost allocation is not applicable because embedded distributors have had the opportunity to review the cost allocation and rate design of the rate applicable to them as part of the regulatory approval process for Hydro One's previous rate applications.

5.0 DEVIATIONS FROM THE FILING REQUIREMENTS

Hydro One has compiled with the OEB's policies and guidelines set out in the Handbook and Filing Requirements. Where modifications to the OEB's workforms were necessary, they are noted in the checklists therein, filed at Attachments 1 and 2 of this exhibit.

6.0 CHANGES TO METHODOLOGY & DESCRIPTION OF WHAT CHANGED

Hydro One included a list of major changes to its methodology compared to previous applications as it impacts the revenue requirement, for which it seeks approval in this Application:

1. <u>Change in the revenue cap index for Transmission and Distribution.</u> Hydro One proposes the use of a cumulative productivity and stretch factors, and incremental stretch factor of 0.15% on capital, in the determination of the 2024 to 2027 revenue requirement. With respect to productivity targets, Hydro One will modify its approach to align the productivity targets to the stretch factors developed as part of the custom IR

framework. See Exhibits A-04-01 to A-04-03 for the proposed custom IR framework and SPF Section 1.4 related to changes to the productivity framework.

2. Change in the treatment of PCB Retirement and Waste Management program (PCB) program costs for Transmission and Distribution. Hydro One proposes to reclassify PCB costs back into OM&A, as opposed to continuing to recognize this expense as a Depreciation and Amortization expense in revenue requirement. See Exhibit D-01-01 for details.

Transmission Filing Requirements Checklist

Hydro One Networks Inc. (Transmission)

EB-2021-0110

Adopted from 2016 Filing Requirement For Electricity Transmitters

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
			Date: August 5, 2021
GENERAL REQUIREMENTS			
Ch 1, p 2	Certification that the evidence filed is accurate, consistent and complete	Yes	Attachment 1 to Exhibit A-02-01
3	Confidential Information - Practice Direction has been followed	Yes	Exhibit A-02-01
Ch 2, p 4	Provide Chapter 2 appendices that are applicable to their transmission applications	Yes	Applicable Chapter 2 appendices are filed under each of the respective exhibits: For App 2-A, please see Exhibit A-02-01 App 2-AA: TSP Section 2.9 Attachment 1; GSP Section 4.9 Attachment 1 App 2-AB: TSP Section 2.8 Attachment 1; GSP Section 4.8 Attachment 1 Attachment 1 of Exhibit A-07-01 (App 2-AC) Exhibit C-04-04 (App 2-BA) Appendix 2-BB - Not Applicable, as Hydro One has filed its custom depreciation study at Attachment 1 of Exhibit E-08-01 Attachment 2 of Exhibit E-08-01 Attachment 1 of Exhibit C-08-02 (App 2-D) Attachment 2 of TSP Section 2.5 (App 2-G) Attachment 1 of Exhibit D-02-01 (App 2-H) Attachment 2 of Exhibit D-05-01 (App 2-IB) Attachment 1A of Exhibit E-02-01 (App 2-JA, 2-JB, 2-JC, 2-L) Attachment 2A of Exhibit E-06-01 (App 2-K) Attachment 3 of Exhibit E-07-01 (App 2-KA) Attachment 1 of Exhibit E-10-01 (App 2-M) Attachment 1 of Exhibit E-04-01 (App 2-N) Exhibits F-01-03 & F-01-04 (App 2-OA, 2-OB)
4	Written direct evidence is to be included before data schedules	Yes	Confirmed
4	Average of the opening and closing fiscal year balances must be used for items in rate base	Yes	Exhibit C-01-01
4	Total capitalization (debt and equity) must equate to total rate base	Yes	Exhibit F-01-03: Appendix 2-OA
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	Hydro One has provided the required data in its evidence, Chapter 2 appendices applicable to Transmission, and in its custom spreadsheets
4	Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts	Yes	See Exhibit A-02-03, section 3 regarding how Hydro One's Application aligns with expectations for a Custom IR application
4	Documents are to be provided in bookmarked and text-searchable Adobe PDF format	Yes	Confirmed
4	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical	Yes	Confirmed
6	Materiality threshold	Yes	Exhibit A-02-03 TSP Section 2.11, TSP Section 2.09 Attachment 2, GSP Section 4.11, GSP Section 4.9 Attachment 2
6	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing	Yes	Exhibit A-06-01 (accounting standards) Exhibit A-02-03 (summary of changes in methodology)
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-03-01
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-03-01 Attachment 1 of A-03-01: Business Plan
8	Revenue Requirement - request, changes from previous revenue requirement and drivers of change	Yes	Exhibit A-03-01
8	Budgeting Assumptions - Economic overview	Yes	Exhibit A-03-01
8	Load Forecast - Load growth and forecast methods	Yes	Exhibit A-03-01
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	Summary of drivers and elements of plan - TSP Section 2.1 and GSP Section 4.1; Details of Investment Planning Process - SPF Section 1.7; TSP Section 2.7 and GSP Section 4.7; Capital Expenditures -TSP Section 2.8 and GSP Section 4.8; Changes in Capital Expenditures - TSP Section 2.9 and GSP Section 4.9
9	Rate Base - Request for test years and change from last OEB approved	Yes	Exhibit A-03-01
9	Performance and Reporting - Proposed scorecard	Yes	SPF Section 1.5 and TSP Section 2.5
9	OM&A - Request for test years, changes from last OEB approved and drivers of change	Yes	Exhibit A-03-01
9	Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology	Yes	Exhibit A-03-01
9	Cost Allocation + Rate Design - Summary of how costs are allocated to rate pools	Yes	Exhibit A-03-01
10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts	Yes	Exhibit A-03-01
10	Bill Impacts - Summary of impacts at wholesale level and for typical retail customers	Yes	Exhibit A-03-01
Customer Engagement			
Ch 2, p 10	Customer engagement process and activities	Yes	SPF Section 1.6; Attachments 1 through 5 TSP Section 2.7
10	Customer needs including end-use load customers and generator customers	Yes	SPF Section 1.6; Attachments 1 through 5 TSP Section 2.7
10	How the application responds to customer needs	Yes	TSP Section 2.7
10	Customer satisfaction surveys	Yes	SPF Section 1.6; Attachments 1 through 5
10	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence	Yes	Attachment 1 of Exhibit A-07-01
11	Responses to letters of comment	N/A	Hydro One has not yet received letters of comment filed with the OEB
Financial Information			
Ch 2, p 11	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	Yes	Exhibit A-06-02; Attachments 1 & 2 of Exhibit A-06-02
11	Detailed reconciliation of AFS with regulatory financial results	Yes	Exhibit A-06-04
11	Annual Report and MD&A for most recent year of parent company	Yes	Attachments 1 & 2 of Exhibit A-06-06 (Hydro One Limited's 2019 and 2020 Annual Reports including MD&A)
	Rating Agency Reports	Yes	Attachments 1 to 3 of Exhibit A-06-03
11	Prospectuses & information circulars for recent and planned public offerings	Yes	Attachment 1 of Exhibit A-06-05

Administration			
Ch 2, p 11	Table of Contents	**Yes**	Exhibit A-01-01
11	Statement identifying customers materially affected by the application	**Yes**	Exhibit A-02-01
12	Internet address for viewing of application	**Yes**	Exhibit A-02-01
12	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit A-02-01
12	Identification of legal representation	**Yes**	Exhibit A-02-01
12	Requested effective date	**Yes**	Exhibit A-02-01
12	Bill impacts for typical Ontario residential customer and Ontario General Service customer	**Yes**	Exhibit A-02-01
12	Form of hearing requested (written or oral)	**Yes**	Exhibit A-02-01
12	List of approvals requested including accounting orders	**Yes**	Exhibit A-02-01
12	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	**Yes**	Exhibit A-02-01; Exhibit A-02-03, and Exhibit A-04-02
12	Changes in tax status	**Yes**	Exhibit E-09-01
12	Existing Accounting Orders	**Yes**	Exhibit G-01-01, and Attachment 4 of Exhibit G-01-01: Per Filing Requirement, Hydro One has provided a description of the existing accounting orders by listed account, which includes detail on what is recorded in each account as approved by the OEB and how the balance in the account has been calculated.
12	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	**Yes**	TSP Section 2.1
12	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	**Yes**	Exhibit A-05-01 Attachment 1 of A-05-01: Corporate entities relationship chart (organizational structure) Attachment 2 of A-05-01: Hydro One organization structure
13	The Accounting Standard used and when it was adopted	**Yes**	Exhibit A-06-01
13	Deviations from filing requirements, if any	**Yes**	Exhibit A-02-03
13	Changes to methodologies used in previous applications	**Yes**	Exhibit A-02-03
13	Confirmation that accounting treatment is segregated for non-regulated business	**Yes**	Exhibit A-06-04
13	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application	**Yes**	Exhibit A-02-04
EXHIBIT 2 - Transmission System Plan			
General			
Ch 2, p 13	Refer to Chapter 5 of the Distribution Filing Requirements	**Yes**	TSP Section 2.0; GSP Section 4.0
13	The strategic plan for the utility and investment strategy	**Yes**	Exhibit A-03-01 Attachment 1; TSP Section 2.1; GSP Section 4.1
13	The longer term economic and planning assumptions	**Yes**	SPF Section 1.7
13	The asset management plan	**Yes**	SPF Section 1.7; TSP Section 2.7; GSP Section 4.7
13	A description of how investments are prioritized and selected	**Yes**	SPF Section 1.7; TSP Section 2.7; GSP Section 4.7
13	A discussion of transmission investments identified in the regional planning process	**Yes**	SPF Section 1.2
13	Highlights of recent and proposed investments and their fit with the strategic plan	**Yes**	TSP Section 2.1, 2.8, 2.9; GSP Section 4.1, 4.8, 4.9
13	A description of how the needs of customers and overall system planning policy objectives are being reflected	**Yes**	SPF Section 1.6 and 1.7; TSP Section 2.7; GSP Section 4.6, 4.7
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 renewables	**Yes**	TSP Section 2.6
Asset Management Plan			
Ch 2, p 14	Asset management policy, strategy and objectives	**Yes**	SPF Section 1.7; TSP Section 2.7; GSP Section 4.7
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; GSP Section 4.2
14	Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	**Yes**	There are no exemptions being sought from NERC or any material costs expected
Regional Considerations			
Ch 2, p 14	Regional planning process demonstrating that regional considerations have been considered and addressed	**Yes**	SPF Section 1.2
14	Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP	**Yes**	SPF Section 1.2
14	Identify investments spanning more than one region	**Yes**	SPF 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**	SPF Section 1.2
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**	Exhibits C-04-02 to C-04-05
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 2.11; GSP Section 4.11
16	Drivers of capital expenditure increases for the test year(s)	**Yes**	TSP Section 2.8; GSP Section 4.8
16	The basis for the estimated budget for the project or program	**Yes**	TSP Section 2.8, 2.11; GSP Section 4.8, 4.11
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 2.8, 2.11; GSP Section 4.8, 4.11
17	Written explanation of capital expenditure variances	**Yes**	TSP Section 2.9; GSP Section 4.9
17	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	**Yes**	Exhibit C-08-01
17	Cost benchmarking studies or utility cost comparisons	**Yes**	Exhibit A-04-01; SPF Section 1.4; SPF Section 1.8; TSP Section 2.3; GSP Section 4.3; Exhibit C-08-02; Exhibit E-04-02; Exhibit E-06-01
17	Continuous improvement or efficiency gains, how they will be achieved and benefit customers	**Yes**	Exhibit A-04-01
17	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income	**Yes**	Exhibit A-04-01

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-01-01 (Rate Base); Exhibit C-04-01
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-01-01 Exhibit C-04-02 (Gross Fixed Assets) Exhibit C-04-03 (Accumulated Depreciation) Exhibit C-04-04 (Appendix 2-BA) Exhibit C-04-05 (CWIP)
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-01-01 Exhibit C-04-02 and C-04-03 Exhibit C-04-04 (Appendix 2-BA)
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-01-01 Exhibit C-04-04 (Appendix 2-BA)
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-04-01 - breakdown for electric utility plant Exhibit C-04-04 (Appendix 2-BA)
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-04-04 (Appendix 2-BA)
19	Detailed breakdown of the in-service capital additions for the test year(s)	**Yes**	Exhibit C-02-01
19	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	**Yes**	Exhibit C-04-04 (Appendix 2-BA) Attachment 2 of Exhibit E-08-01 (Depreciation & Amortization expense)
Allowance for Working Capital			
Ch 2, p 19	Working Capital - Lead/Lag Study	**Yes**	Exhibit C-05-01; Attachment 1 of Exhibit C-05-01 (Hydro One Transmission - Lead/Lag Study)
19	Lead/Lag Study - leads and lags measured in days, dollar-weighted	**Yes**	Attachment 1 of Exhibit C-05-01 (Hydro One Transmission - Lead/Lag Study)
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**	Attachment 1 of Exhibit C-05-01 (Hydro One Transmission - Lead/Lag Study)
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-07-01; capital / in-service additions included in rate base are net of customer contributions
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-07-01
20	Financial and regulatory accounting treatment of true-up proceeds.	**Yes**	Exhibit C-07-01
Capitalization Policy			
Ch 2, p 20	Capitalization policy, including changes since the last revenue requirement application	**Yes**	Exhibit C-08-02
20	Overhead costs on self-constructed assets	**Yes**	Exhibit C-08-02
20	Identification of burden rates and burden rates prior to changes, if any	**Yes**	Exhibit C-09-01
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**	Not Applicable - Hydro One is not requesting ACM
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**	Not Applicable - Hydro One is not requesting ACM
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**	TSP Section 2.5
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**	TSP Section 2.4 and 2.5
22	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	**Yes**	TSP Section 2.4
22	Compare system performance with other systems both nationally and internationally	**Yes**	TSP Section 2.4
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	**N/A**	There are no outstanding areas of non-compliance that have had a direct effect on the application
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**	Exhibits D-03-01 and D-04-01
23	Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses	**Yes**	Exhibit D-04-01
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 D-04-01
23	Impact of forecast embedded generation on the transmission system load accounted for	**Yes**	Exhibit D-04-01
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 D-04-01, Table 6 and Appendix E
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**	Comparison with IESO forecast: Exhibit D-04-01, Appendix F; Year-over-year comparisons: Exhibit D-04-01, Appendix G
24	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	**Yes**	Exhibit D-04-01-01 for load data, and Exhibit D-03-01-01 for economic and demographic data

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 D-02-01
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 D-02-01
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 D-02-03 Attachment 1 to Exhibit E-04-01
24	Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	**Yes**	Confirmed
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 E-02-01
Summary and Cost Driver Tables			
Ch 2, p 26	Summary of recoverable OM&A expenses	**Yes**	Attachments 1A & 1B of Exhibit E-02-01: Tab 2-JA
26	Recoverable OM&A cost drivers	**Yes**	Attachments 1A & 1B of Exhibit E-02-01: Tab 2-JB
26	Change in OM&A in test year attributable to a change in capitalized overhead	**Yes**	Attachment 1 of Exhibit C-08-02: Appendix 2-D
26	OM&A variance analysis for test year with respect to bridge and historical years	**Yes**	Exhibit E-02-01
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**	Attachment 2B of Exhibit E-06-01 (employee compensation) Exhibit E-04-02 (shared services/corporate cost allocation) Exhibit E-05-01 (purchase of non-affiliate services) Exhibits E-10-01, E-10-02, and E-10-03 (OEB costs; one-time costs; charitable and political donations)
Employee Compensation			
Ch 2, p 26	Employee complement, compensation and benefits	**Yes**	Exhibit E-06-01
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 E-06-01; Attachment 2B of Exhibit E-06-01; Compensation benchmarking study: Attachment 1 of Exhibit E-06-1
27	Employee benefit programs including pensions	**Yes**	Exhibit E-07-01 (pensions & OPEBs); Exhibit E-06-01 (corporate staffing and compensation) Attachment 3 of Exhibit E-07-01
27	Most recent actuarial reports	**Yes**	Attachment 1 of Exhibit E-07-01 (actuarial valuation as of December 31, 2018)
Shared Services and Corporate Cost Allocation			
Ch 2, p 27	Identification of shared services	**Yes**	Exhibit E-04-02
27	Allocation methodology for corporate and shared services	**Yes**	Exhibit E-04-08
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**	Exhibits E-04-02 and D-02-03
28	Variance analysis - test year vs last OEB approved and most recent actual	**Yes**	Exhibit E-04-02
28	Identification of any Board of Director costs for affiliates included in LDC costs	**Yes**	Exhibit E-04-08
Purchase of Non-Affiliate Services			
28	Procurement Policy	**Yes**	Exhibits E-05-01, E-05-02, E-05-02 Attachment 1 Exhibit C-06-01 Attachment 1
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	**N/A**	Not Applicable - all material transactions are in compliance
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 E-10-02
Regulatory Costs			
28	Regulatory costs - breakdown of actual and forecast costs Supporting information, legal fees, consultant fees, costs awards, etc.	**Yes**	Exhibit E-10-01 Attachment 1 of E-10-01: Appendix 2-M
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 E-10-03
29	Detailed information for all contributions that are claimed for recovery	**N/A**	Exhibit E-10-03
29	Charitable Donations - confirmation that political contributions not included	**N/A**	Exhibit E-10-03
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**	Attachment 2 of Exhibit E-08-01
29	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	**Yes**	Exhibit E-08-01
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 E-08-01
29	Depreciation/amortization policy Summary of changes to depreciation/amortization policy since last CoS	**Yes**	Exhibit E-08-01 (equivalent written description has been provided); Attachment 1 of Exhibit E-08-01
29	Explanation of any deviations from depreciating components of PP&E separately	**N/A**	Not Applicable - Hydro One does not have different practices of depreciating parts or components of PP&E separately
Taxes or PILs and Property Taxes			
30	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years	**Yes**	Attachments 1 to 6 of Exhibit E-09-02
30	Supporting schedules and calculations identifying reconciling items	**Yes**	Attachments 1 to 4 of Exhibit E-09-02
30	Most recent federal and provincial tax returns	**Yes**	Attachment 1 of Exhibit E-09-03
30	Financial Statements included with tax returns if different from those filed with application	**N/A**	Not Applicable - there are no differences in financial statements included with tax returns
30	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	**Yes**	Attachments 5 and 6 of Exhibit E-09-02
30	Supporting schedules, calculations and explanations for other additions and deductions	**Yes**	Exhibit E-09-01
Non-recoverable and Disallowed Expenses			
30	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	**Yes**	Exhibit E-09-01 - confirmed

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 E-09-01
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 E-09-01
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 E-09-01
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 E-09-01
31	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	**No**	Exhibit E-09-01
31	CCA is maximized even if there are tax loss carry-forwards	**Yes**	Exhibit E-09-01
31	A statement is included in the application as to when the losses, if any, will be fully utilized	**Yes**	Exhibit E-09-01
31	Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation	**Yes**	Exhibit E-09-01
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 E-09-01
Z-Factor Claims			
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 E-10-04
EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
33	OEB's cost of capital parameters used	**Yes**	Exhibit F-01-02
33	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	**Yes**	Exhibit F-01-02
33	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	**Yes**	Exhibit F-01-03: Appendix 2-OA Exhibit F-01-04: Appendix 2-OB
33	Explanation for any changes in capital structure	**Yes**	Exhibit F-01-02
Cost of Capital (Return on Equity and Cost of Debt)			
34	Calculation of cost for each capital component	**Yes**	Exhibit F-01-02
34	Profit or loss on redemption of debt	**Yes**	Exhibit F-01-02
34	Copies of promissory notes or other debt arrangements with affiliates	**Yes**	Exhibit F-01-02
34	Explanation of debt rate for each existing debt instrument	**Yes**	Exhibit F-01-02
34	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Exhibit F-01-02
34	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	**Yes**	Exhibit F-01-02
Not-for-Profit Corporations			
34	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	**N/A**	Not Applicable - Hydro One is not a not-for-profit corporation
EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS			
34	List of all outstanding DVA and sub-accounts; provide description of DVAs	**Yes**	Exhibit G-01-01
34	Completed DVA continuity schedule for period following last disposition to present - live Excel format	**Yes**	Attachment 1 of Exhibit G-01-05 (Hydro One Transmission)
34	Confirm use of interest rates established by the OEB by month or by quarter for each year	**Yes**	Exhibit G-01-01
35	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	**Yes**	Exhibit G-01-05 Attachment 2 of Exhibit G-01-05 (Tab: Appendix A)
35	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	**Yes**	Exhibit H-01-03
35	Statement as to any new accounts, and justification.	**Yes**	Exhibit G-01-02
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 G-01-01 Exhibit G-01-03
Disposition of Deferral and Variance Accounts			
36	Identify accounts for which disposition is sought	**Yes**	Exhibit G-01-01
36	Identify accounts for which disposition is not sought and the reasons	**Yes**	Exhibit G-01-01
36	Propose the method to be used for recovery or refund of balances that are proposed for disposition	**Yes**	Exhibit H-01-03
36	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	**Yes**	Exhibit G-01-03
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**	Exhibit G-01-03
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**	Not Applicable
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-01-03
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 H-01-03
36	Steps taken to functionalize the assets in the functional categories	**Yes**	Exhibit H-01-02
36	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	**Yes**	Exhibit H-05-01; Exhibit H-03-01; Exhibit H-03-02; Exhibit H-03-03; and Exhibit H-04-01
36	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	**Yes**	Exhibit H-04-02; Exhibit H-04-03; and Exhibit H-04-04
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 H-10-01
37	Bill impacts for typical customers and consumption levels.	**Yes**	Exhibit H-10-01
Setting the Uniform Transmission Rates			
37	Overview of how the UTR are established in Ontario and how these rates are determined	**Yes**	Exhibit H-06-01
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 H-11-01-02
37	Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	**Yes**	Exhibit H-09-01
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 H-11-01-02 and Exhibit H-11-02-02 Not Applicable re: explanation of any changes to terms and conditions of service

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch 1, Pg. 2	Certification by a senior officer that the evidence filed is accurate, consistent and complete	Attachment 1 to Exhibit A-02-01
Ch 1, Pg. 3-4	Confidential Information - Practice Direction has been followed	Exhibit A-02-01
Ch 1, Pg. 4	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable).	Attachment 2 to Exhibit A-02-01
Ch 2, Pg. 2	Statement identifying all deviations from Filing Requirements	Exhibit A-02-03
2	Chapter 2 appendices in PDF and live Microsoft Excel format; PDF and Excel copy of current tariff sheet	Chapter 2 appendices are filed under each of the respective exhibits: For App 2-A, please see Exhibit A-02-01 Attachment 1 of DSP Section 3.9 (App 2-AA) Attachment 1 of DSP Section 3.8 (App 2-AB) Attachment 1 of Exhibit A-07-01 (App 2-AC) Exhibit C-04-04 (App 2-BA) Appendix 2-BB - Not Applicable, as Hydro One has filed its custom depreciation study at Attachment 1 of E-08-01 Attachment 2 of E-08-01 Attachment 1 of Exhibit C-08-02 (App 2-D) App 2-FA, FB, FC - Not requested in this Application Attachment 1 of Exhibit A-05-03 (App 2-G) Attachment 1 of Exhibit D-02-02 (App 2-H) Attachment 2 of Exhibit D-05-01 (App 2-IB) Attachment 1A of Exhibit E-03-01 (App 2-JA, 2-JB, 2-JC, 2-L) Attachment 2A of Exhibit E-06-01 (App 2-K) Attachment 3 of Exhibit E-07-01 (App 2-KA) Attachment 1 of Exhibit E-10-01 (App 2-M) Attachment 1 of Exhibit E-04-01 (App 2-N) Exhibit F-01-03, F-01-04 (App 2-OA, 2-OB) App 2-Q is not applicable as embedded distributors fall within the Hydro One ST class Attachment 1 of Exhibit L-06-02 (App 2-R) Exhibit C-05-03 (App 2-ZA, 2-ZB)
3	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year.	Not Applicable - Hydro One has filed its Application well in advance of 2023 rebasing
3	If aligning rate year with fiscal year, application filed no later than the end of April of the year prior to the test year	Not Applicable - Hydro One's effective and implementation date for HONI Distribution and LDC Acquireds is Jan 1, 2023
4	Text searchable and bookmarked PDF documents	Confirmed
5	Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed for the links in Chapter Appendices 2 models and other models filed with the related exhibits
5	Materiality threshold; additional details below the threshold if necessary (for rate base, capital expenditures and OM&A)	Exhibit A-02-03 DSP Section 3.12, and Section 3.9 (Attachment 2) GSP Section 4.11, and Section 4.9 (Attachment 2)
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
Table of Contents		
6	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section	Exhibit A-01-01
Executive Summary and Business Plan		
6	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals	Exhibit A-03-01 Attachment 1 of A-03-01: Business Plan
Customer Summary		
7	Brief but complete summary of the application that will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of the applicant. Must include: main requests (with section references), description of impacts of requests, bill impact for customer at 750kWh as well as a typical consumer for a distributor's service area for each of the residential and small business customer classes (bill impacts to be based on commodity rates based on TOU and reg. charges held constant)	Attachment 2 of Exhibit A-07-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Administration		
7	Primary contact information (name, address, phone, fax, email)	Exhibit A-02-01
7	Identification of legal (or other) representation	Exhibit A-02-01
7	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	Exhibit A-02-01
7	Statement identifying where notice should be published and why	Exhibit A-02-01
7	Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers	Exhibit A-02-01
7	Form of hearing requested and why	Exhibit A-02-01
7	Requested effective date	Exhibit A-02-01
8	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit A-02-03
8	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	Exhibit A-02-04
8	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit A-02-01 Exhibit A-02-03, Attachment 3
8	Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit A-05-01 Attachment 1 of A-05-01: Corporate entities relationship chart (organizational structure) Attachment 2 of A-05-01: Hydro One organization structure
8	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be separately identified in Appendix 2-A and clearly documented in the appropriate sections of the application - a PDF copy of Appendix 2-A should be provided in this section	Exhibit A-02-01
Distribution System Overview		
8	Description of Service Area (including map, communities served)	DSP Section 3.1
8 & 9	Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW	Exhibit A-02-03
9	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	DSP Section 3.1
Application Summary At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.		
9	Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers	Exhibit A-03-01
9	Budgeting and Accounting Assumptions - economic overview (such as growth and inflation), and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	Exhibit A-03-01
9	Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers from last OEB-approved, description of forecasting method(s) used for customer/connection and consumption/demand	Exhibit A-03-01
9 & 10	Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery	Exhibit A-03-01
10	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers and cost trends, inflation assumed, total compensation for test year and change from last approved ($ and %).	Exhibit A-03-01
10	Cost of Capital - summary table showing proposed capital structure and cost of capital parameters used in WACC. Statement regarding use of OEB's cost of capital parameters; summary of any deviations	Exhibit A-03-01
10	Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans	Exhibit A-03-01
10	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested and any requested discontinuation of existing DVAs	Exhibit A-03-01
10	Bill Impacts - total impacts ($ and %) for all classes for typical customers	Exhibit A-03-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Customer Engagement		
10 & 11	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	SPF Section 1.6; Attachments 1 through 5 DSP Section 3.7
11	Discussion of any feedback provided by customers and how the feedback shaped the final application	SPF Section 1.6; Attachments 1 through 5 DSP Section 3.7
11	Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5	SPF Section 1.6 DSP Section 3.6 DSP Section 3.7
11	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities. Provide summary of feedback received through engagement activities.	SPF Section 1.6; Attachments 1 through 5 DSP Section 3.7
11	Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application	Attachment 1 of Exhibit A-07-01
11	All responses to matters raised in letters of comment filed with the OEB	Hydro One has not yet received letters of comment filed with the OEB
Performance Measurement		
11 & 12	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement currently and going forward	DSP Section 3.5
12	Identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application	DSP Section 3.5 Exhibit A-05-02 Exhibit A-05-02, Attachment 1
12	Activity and Performance-based Benchmarking (APB) results - discussion of performance for each of the ten programs and provide any immediate remedial actions distributor plans to take. Distributors may include how the APB results will influence future planning	DSP Section 3.5
Facilitating Innovation		
13	In order to support the OEB's consideration of its new objective to facilitate innovation in the electricity sector, it would be helpful for distributors to include in their cost-based applications a description of the ways that their approach to innovation have shaped the proposals in the application. This could include an explanation of its approach to innovation in its business more generally, or related to specific projects, including enabling characteristics or constraints in its ability to undertake innovative solutions for enhancing the provision of distribution services in a way that benefits customers.	SPF Section 1.8 DSP Section 3.8 DSP Section 3.11, D-SR-12, D-SS-04, D-SS-05 GSP Section 4.8 GSP Section 4.11, G-GP-08
Financial Information		
13	Non-consolidated Audited Financial Statements for 3 most recent historical years (i.e. 2 years statements must be filed, covering 3 years of historical actuals)	Exhibit A-06-02; Attachments 3 & 4 of Exhibit A-06-02
13	Detailed reconciliation of AFS with regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non-distribution business. This must include identification of any deviations that are being proposed between AFS and regulatory financial results, including the identification of any prior OEB approvals for such deviations	Exhibit A-06-04
13	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	Attachments 1 & 2 of Exhibit A-06-06 (Hydro One Limited's 2019 and 2020 Annual Reports including MD&A) Attachments 3 & 4 of Exhibit A-06-02 (Hydro One Networks' 2018 to 2020 Annual Reports including MD&A)
13	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	Attachments 1 to 3 of Exhibit A-06-03 (rating agency reports) Attachment 1 of Exhibit A-06-05 (prospectuses)
13	Any change in tax status	Exhibit E-09-01
13	Existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit G-01-01, and Attachment 4 of Exhibit G-01-01: Per Filing Requirement, Hydro One has provided a description of the existing accounting orders by listed account, which includes detail on what is recorded in each account as approved by the OEB and how the balance in the account has been calculated.
13	Accounting Standards used for financial statements and when adopted	Exhibit A-06-01
13 & 14	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	Exhibit A-06-04
Distributor Consolidation		
14	If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must specify whether any commitments made to shareholders are to be funded through rates	Not Applicable - no incentives (see Exhibit A-08-01)
14	List of exhibits in application in which incentives are discussed	Not Applicable - no incentives (see Exhibit A-08-1)
14	Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application	Exhibit L-03-01
14	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	Not Applicable - Hydro One did not apply for an ACM or ICM from a previous price cap application

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 2 - RATE BASE		
Overview		
15	Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format	Exhibit C-04-04: Appendix 2-BA
15	For rate base, must include opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast)	Exhibit C-01-01 (Rate Base) ; Exhibit C-04-01 Exhibit C-05-01 (Working Capital Allowance)
15	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 (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	Exhibit C-01-01 Exhibit C-04-02 (Gross Fixed Assets) Exhibit C-04-03 (Accumulated Depreciation) Exhibit C-04-04 (Appendix 2-BA) Exhibit C-04-05 (CWIP)
15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit C-01-01 Exhibit C-04-02 and C-04-03 Exhibit C-04-04 (Appendix 2-BA)
16	Distributor may include in-service balances previously recorded in DVAs, such as MIST meters or renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, but disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	Exhibit C-01-01 Exhibit C-04-04 (Appendix 2-BA)
Gross Assets - PP&E and Accumulated Depreciation		
16	Breakdown by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses	Exhibit C-04-01 - breakdown for electric utility plant Exhibit C-04-04 (Appendix 2-BA)
16	Breakdown by major plant account for each functionalized plant item; for test year, each plant item must be accompanied by description	Exhibit C-04-01 - breakdown for electric utility plant Exhibit C-04-04 (Appendix 2-BA)
16	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Not Applicable No ICMs or ACMs approved from previous IRM applications
16	Continuity statements must reconcile to calculated depreciation expenses under Exhibit 4 and presented by asset account	Exhibit C-04-04 (Appendix 2-BA) Attachment 2 of Exhibit E-08-01 (Depreciation & Amortization expense)
16	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	Attachment 2 of Exhibit E-08-01
Allowance for Working Capital		
16 & 17	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	Exhibit C-05-01; Attachment 2 of Exhibit C-05-01 (Hydro One Distribution - Lead/Lag Study)
17	Lead/Lag Study - leads and lags measured in days, dollar-weighted	Attachment 2 of Exhibit C-05-01 (Hydro One Distribution - Lead/Lag Study)
17	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price, use current UTR. Calculation must include the impact of the most up to date Ontario Electricity Rebate, currently set at of 18.9% on the total bill. Distributors must complete Appendix 2-Z - Commodity Expense.	Exhibit C-05-03 (App 2-ZA and 2-ZB)
Distribution System Plan and Capital Expenditures Summary		
18	DSP filed as a stand-alone document; a discrete element within Exhibit 2	Exhibit B-03-01
18	Overall summary of capital expenditures over the past five historical years, including the last OEB-approved amounts, as well as the bridge year and the test year. The summary must show capital expenditures, treatment of contributed capital, and additions and deductions from CWIP. As part of Exhibit 2, a distributor must also provide explanations of year-over-year variances and an explanation of the variance, if any, between the OEB-approved capital expenditure amount in the last rebasing year as compared to the actual expenditures for that year.	DSP Section 3.8 DSP Section 3.8. Attachment 1 DSP Section 3.9, Attachment 2
18	Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category.	DSP Section 3.8, Attachment 1 GSP Section 4.8, Attachment 1
Policy Options for the Funding of Capital		
18 & 19	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification	Not Applicable; Hydro One is not requesting an ACM
18 & 19	Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information. The ACM Report provides further details on the information required.	Not Applicable; Hydro One is not requesting an ACM
19	Complete Capital Module Applicable to ACM and ICM	Not Applicable; Hydro One is not requesting an ACM
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
19 & 20	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base. The distributors must compare actual capital spending with OEB-approved amount and provide an explanation for variances	Not Applicable; Hydro One is not requesting an ACM
20	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	Not Applicable; Hydro One is not requesting an ACM
20 & 21	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Not Applicable; Hydro One is not requesting an ACM

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Capitalization Policy		
21	Capitalization policy including changes since its last rebasing application. Must identify the changes and the causes of the changes.	Exhibit C-08-02
Capitalization of Overhead		
21	Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any	Attachment 1 to Exhibit C-08-02: Appendix 2-D Exhibit C-09-01
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
22 & 23	Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements - Appendices 2-FA through 2-FC identifying all eligible investments for recovery	Not Applicable. Hydro One is not making this request as part of this Application.
Service Quality		
23	5 historical years of SQRs, explanation for any under-performance vs standard and actions taken. If available, any outcomes of such actions.	Exhibit A-05-03
23	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Exhibit A-05-03, Attachment 1
Ch5 p7-8	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	DSP Section 3.0
Ch5 p8-9	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	DSP Section 3.0 DSP Section 3.1 DSP Section 3.2
Ch5 p9-10	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - IESO letter in relation to REG investments (Ch 5 p9) and Dx response letter	DSP Section 3.4 DSP Section 3.4, Attachment 1
Ch5 p10-12	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	DSP Section 3.5
Ch5 p12	Realized efficiencies due to smart meters -documented capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies. Both qualitative and quantitative descriptions should be provided	DSP Section 3.5, Attachment 8
Ch5 p12-13	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	SPF Section 1.6 DSP Section 3.7 GSP Section 4.7
Ch5 p13	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	SPF Section 1.6
Ch5 p14	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	DSP Section 3.1 DSP Section 3.2 GSP Section 4.2
Ch5 p14-15	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	DSP Section 3.2 GSP Section 4.2
Ch5 p15-16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	DSP Section 3.4
Ch5 p16	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	DSP Section 3.8 GSP Section 4.8
Ch5 p17-18	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to priorities REG investments	DSP Section 3.2 DSP Section 3.3 DSP Section 3.4 DSP Section 3.6 DSP Section 3.7 DSP Section 3.8
Ch5 p18	Rate-Funded Activities to Defer Distribution Infrastructure -CDM programs that target distributor-specific peak demand reductions to address a local constraint of the distribution system -demand response programs to reduce peak demand in order to defer capital investment -programs to improve the efficiency of the distribution system and reduce distribution losses -energy storage programs whose primary purpose is to defer specific capital spending for the distribution system	Not Applicable - Hydro One has not proposed rate funded CDM programs or activities to defer distribution infrastructure in this Application.

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: **August 5, 2021**

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch5 p19-20	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) - Must also complete Chapter 2 Appendix 2-AA, along with explanations of variances by project or category, the proposed accounting treatments, a statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget	DSP Section 3.8, Attachment 1 DSP Section 3.9, Attachment 1 GSP Section 4.8, Attachment 1 GSP Section 4.9, Attachment 1
Ch5 p20	Justifying Capital Expenditures -filings must enable OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization, and pacing of capital-related expenditures -distributors should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability	DSP Section 3.8 DSP Section 3.9
Ch5 p20-21	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	DSP Section 3.2 DSP Section 3.8 DSP Section 3.9
Ch5 p21-28	Material Investments - For each project that meets materiality threshold set in Ch 2 p5 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	DSP Section 3.11 DSP Section 3.11, Attachments GSP Section 4.11 GSP Section 4.11, Attachments
EXHIBIT 3 - OPERATING REVENUE		
Load and Revenue Forecasts		
23	Explanation of causes, assumptions and adjustments for volume forecast, including economic assumptions and data sources for customer and load forecasts	Exhibits D-03-01 and D-05-01
23	Explanation of weather normalization methodology	Exhibit D-05-01
24	Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10	Attachment 2 of Exhibit D-05-01 and Attachment 1 of D-03-01
24 & 25	Multivariate Regression Model - rationale for choice, regression statistics (including explanation for any resulting unintuitive relationships), explanation of weather normalization methodology, sources of data for endogenous and exogenous variables (where a variable has been constructed, a complete explanation of the variable data used and source), any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data (where such variable has been used, explanation and justification must be provided), explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables	Exhibit D-05-01 Attachment 1 of D-03-01: data used in load forecast (Excel)
25	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM in historical period and how CDM impacts are factored into test year forecast), discussion of weather normalization considerations	Not Applicable - Hydro One does not use a normalized average use model to forecast load
CDM Adjustment for the Load Forecast for Distributors		
26	CDM Adjustment - If a distributor expects impacts from any CFF-related projects not deployed by April 2019 but for which a distributor is contractually obligated to complete, or for other programs delivered by the distributor after April 2019, a distributor may include these amounts as part of a CDM manual adjustment to the 2022 load forecast but must ensure that sufficient supporting evidence is provided for all estimated CDM savings	Not Applicable - Hydro One is not proposing a CDM adjustment to its distribution load forecast
26	If a distributor proposes a CDM adjustment to its 2022 load forecast, it should document the CDM savings to be used as the basis for the 2022 LRAMVA threshold. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable to a customer class, kW. The distributor should document its proposal adequately, including how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs	Not Applicable - Hydro One is not applying for a LRAMVA threshold
26	Appendix 2-I - is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.	Not Applicable - Hydro One is not proposing a CDM adjustment to its distribution load forecast
Accuracy of Load Forecast and Variance Analyses		
26	Completed Appendix 2-IB	Attachment 2 of Exhibit D-05-01
26	For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences	Exhibit D-05-01 and Attachment 2 of Exhibit D-05-01
26 & 27	For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results	Exhibit D-05-01 and Attachment 2 of Exhibit D-05-01
27	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	RRWF Tab 8 - Attachments 6 to 10 of Exhibit D-01-01, Appendix 2-IB, and Attachment 1 of Exhibit L-02-01
27	With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data	Appendix 2-IB at Attachment 2 of Exhibit D-05-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Other Revenue		
28	Completed Appendix 2-H	Exhibit D-02-02, Attachment 1
28	Variance analysis (including explanations for significant variances) - year over year, historical, bridge and test	Exhibit D-02-02
28	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	Exhibit L-04-01: no new specific service charges proposed; Attachment 3 of Exhibit L-04-01: no changes to approved service charges
28	Revenue from affiliate transactions, shared services, corporate cost allocation as described in 2.4.3.2. 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 (Appendix 2-N)	Exhibit D-02-03 Attachment 1 to Exhibit E-04-01
28	Accounts related to affiliate revenue and affiliate expense are shown in the footnote of Appendix 2-H	Exhibit D-02-02, Attachment 1
28	Balances recorded in Account 4375 and Account 4380 must reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historic years, the bridge year and the test year. Any differences must be reconciled	Exhibit D-02-02, Attachment 1 Exhibit E-04-01, Attachment 1
29	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	Not Applicable - no customer groups to be materially impacted by changes.
EXHIBIT 4 - OPERATING COSTS		
Overview		
29 & 30	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends in costs including OM&A per customer (and its components) for the historical, bridge and test years, inflation rate assumed, business environment changes	Exhibit E-03-01
Summary and Cost Driver Tables		
30	Summary of recoverable OM&A expenses; Appendix 2-JA	Attachments 1A & 1B of Exhibit E-03-01: Tab 2-JA
30	Recoverable OM&A cost drivers; Appendix 2-JB	Attachments 1A & 1B of Exhibit E-03-01: Tab 2-JB
30	OM&A programs table; Appendix 2-JC	Attachments 1A & 1B of Exhibit E-03-01: Tab 2-JC
30	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Attachments 1A & 1B of Exhibit E-03-01: Tab 2-L
30	Identification of change in OM&A in test year in relation to change in capitalized overhead.	Exhibit E-04-02 Attachment 1 of Exhibit C-08-02: Appendix 2-D
30	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	Attachment 1 of Exhibit C-08-02: Appendix 2-D
Program Delivery Costs with Variance Analysis		
30	Completed Appendix 2-JC OM&A Programs Table - completed by program; include variance analysis between test year costs against each of the last OEB approved costs and most recent actuals for variances that are outliers based on historical trend. The variance analysis should explain whether the change was within or outside the applicant's control	Exhibit E-03-01 Attachments 1A & 1B of Exhibit E-03-01: Tab 2-JC
30 & 31	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	Attachment 1B of Exhibit E-03-01
Workforce Planning and Employee Compensation		
31	Employee Compensation - completed Appendix 2-K	Attachment 2A of Exhibit E-06-01: Appendix 2-K
31	Description of previous and proposed workforce plans, including compensation strategy	Exhibit E-06-01
31	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, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans, - relevant studies (e.g. compensation benchmarking)	Exhibit E-06-01 Attachment 2 A & 2 B of Exhibit E-06-01 Attachment 1 of Exhibit E-06-1 (Compensation benchmarking)
31	For virtual utilities - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated utility. The status of pension funding and all assumptions used in the analysis must be provided. Three or fewer employees - the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Not Applicable - Hydro One is not a virtual utility
32	Details of employee benefit programs including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit E-07-01 (pensions & OPEBs); Exhibit E-06-01 (corporate staffing and compensation) Attachment 3 of Exhibit E-07-01
32	Most recent actuarial report	Attachment 1 of Exhibit E-07-01 (actuarial valuation as of December 31, 2018)
32	Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition	Exhibit E-07-01
Shared Services and Corporate Cost Allocation		
32	Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility"	Exhibits E-04-01 and E-04-02
32	Allocation methodology for corporate and shared services, pricing methodology, list of costs and allocators, including any third party review	Exhibit E-04-08
33	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	Attachment 1 of Exhibit E-04-01
33	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit E-04-02
33	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit E-04-08

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	Exhibits E-05-01, E-05-02 & E-05-02 Attachment 1 Exhibit C-06-01 Attachment 1
33	For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	Not Applicable - all material transactions complied with Hydro One's Procurement Policies
33 & 34	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	Exhibit E-10-02
34	Regulatory costs - breakdown of actual and anticipated regulatory costs, including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M	Exhibit E-10-01 Attachment 1 of Exhibit E-10-01: Appendix 2-M
34	Information supporting the incremental level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify over what period the costs are proposed to be recovered. For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the Price Cap IR option (i.e. five years). If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.	Exhibit E-10-01 Attachment 1 of Exhibit E-10-01: Appendix 2-M
LEAP, Charitable and Political Donations		
34	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	Not Applicable
34	Detailed information for all contributions that are claimed for recovery	Exhibit E-10-03
34	Charitable Donations - the applicant must confirm that no political contributions have been included for recovery	Exhibit E-10-03
Depreciation, Amortization and Depletion		
35	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Exhibit E-08-01
35	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Attachment 2 of Exhibit E-08-01
35	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	Exhibit E-08-01
35	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit E-08-01
35	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit E-08-01 (equivalent written description has been provided); Attachment 1 of Exhibit E-08-01
35	Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Not Applicable - Hydro One does not have different practices of depreciating parts or components of PP&E separately
36	For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	Attachment 1 of Exhibit E-08-01
Income Tax or PILs		
36	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	Hydro One completed custom spreadsheets rather than using OEB's PILs model at Attachments 1 to 6 of Exhibit E-09-02
36	Supporting schedules and calculations identifying reconciling items	Attachments 1 to 4 of Exhibit E-09-02
36	Most recent federal and provincial tax returns	Attachment 1 of Exhibit E-09-03
36	Financial Statements included with tax returns if different from those filed with application	Not Applicable
37	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	Attachments 5 and 6 of Exhibit E-09-02
37	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit E-09-01
37	Completion of the integrity checks in the PILs Model	Exhibit E-09-01
37 & 38	Accelerated CCA - Distributors must provide: the full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, the method used in calculating the revenue requirement impact recorded in Account 1592, detailed calculations by year for the full revenue requirement impact recorded in Account 1592	Exhibit G-01-01; Attachment 5 of Exhibit G-01-01
Other Taxes		
38	Taxes other than income taxes or PILs, as defined in the APH (e.g. property taxes), should only be included in Account 6105, effective January 1, 2012. Account 6105 is not an OM&A account and should therefore be excluded from all OM&A totals. The applicant should provide an explanation of how these tax amounts are derived.	Exhibit E-09-04
Non-recoverable and Disallowed Expenses		
38	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit E-09-01 - confirmed
Conservation and Demand Management		
39	Statement confirming that costs directly attributable to CDM programs (e.g. staff labour dedicated to such programs) are not included in the revenue requirement to be recovered through distribution rates	Attachment 1B of Exhibit E-03-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Lost Revenue Adjusment Mechanism Variance Account		
39 - 44	Distributors must provide version 6 of LRAMVA Work Form (Excel) when making LRAMVA requests for remaining amounts related to CFF activity. An application for lost revenues should include: Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier, Participation and Cost reports in Excel format made available by the IESO. - Personal information and commercially sensitive information removed. An application for lost revenues should also provide: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format). - statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - details for the forecasted CDM savings included in the LRAMVA calculation including reference to the OEBs approval, or an explanation if there are no forecast CDM savings - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable) - for a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate street lighting savings; Confirmation whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; Confirmation whether the street lighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate street lighting savings For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total) o Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program o A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb). For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information: The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate, the rationale for net-to-gross assumptions used, a breakdown of billed demand and detailed level calculations in live excel format Participation and Cost Reports and detailed project level savings files made available by the IESO to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available. These reports should be filed in excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017. o If a distributor seeks to claim any additional program savings to December 31, 2020: - Related to CCF programs: an explanation must be provided as to how savings have been estimated based on the available data (i.e. IESO's Participation & Cost Reports) and/or rationale to justify the eligibility of the program savings - Related to other programs delivered by a distributor: an explanation and rationale should be provided to justify the eligibility of the additional program savings	Not Applicable - Hydro One is not seeking recovery of LRAMVA balances

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
44	Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence	Exhibit F-01-01
44	Completed Appendix 2-OA for last OEB approved and test year	Exhibit F-01-03: Appendix 2-OA
44	Completed Appendix 2-OB for historical, bridge and test years	Exhibit F-01-04: Appendix 2-OB
44	Explanation for any changes in capital structure	Not Applicable - Hydro One has followed OEB's policy in terms of its capital structure
Cost of Capital (Return on Equity and Cost of Debt)		
44	Calculation of cost for each capital component	Exhibit F-01-02
45	Profit or loss on redemption of debt	Exhibit F-01-02
45	Copies of promissory notes or other debt arrangements with affiliates	Exhibit F-01-02
45	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report	Exhibit F-01-02
45	Forecast of new debt in bridge and test year - details including estimate of rate	Exhibit F-01-02
45	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Exhibit F-01-02
45	Notional Debt - should attract the weighted average cost of actual long-term debt rather than the current deemed long-term debt rate issued by the OEB	Exhibit F-01-02
Not-for-Profit Corporations		
46	The requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	Not Applicable - Hydro One is not a not-for-profit corporation
46	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to build up operating and capital reserves or will be used for other purposes	Not Applicable - Hydro One is not a not-for-profit corporation
46	If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves, provide the specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	Not Applicable - Hydro One is not a not-for-profit corporation
46	If the revenues derived from the return on equity component of the cost of capital will be used for other purposes, provide a statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities). Provide rationale supporting the use of the revenues in this manner. Also provide the governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities	Not Applicable - Hydro One is not a not-for-profit corporation
46	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	Not Applicable - Hydro One is not a not-for-profit corporation
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY		
47	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) and for which disposition is not being sought in the application.	Attachments 6 to 10 of Exhibit D-01-01
47	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit D-01-01
47	Impacts of any changes in methodologies to deficiency/sufficiency	Not Applicable - no change in methodology to deficiency/sufficiency
Revenue Requirement Work Form		
48	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Exhibit D-01-01
48	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	Exhibit L-02-01, Attachment 1 Exhibit L-02-01, Attachment 2

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
48	Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Updated load profiles or scaled version of HONI CAIF. Model must be consistent with test year load forecast, changes to customer classes and load profiles.	Cost allocation model (CAM) filed at Exhibit L-01-03-01
48 & 49	Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed	Not Applicable – see CAM filed at Exhibit L-01-03 Attachment 1, where demand data at Tab I8 is derived from updated load profiles and load forecast
49	Provide spreadsheet and a description with example calculations to show how the demand data in the cost allocation model was derived from the load forecast and load profiles	Attachment 3 of Exhibit D-05-01
49	Description of weighting factors, and rationale for use of default values (if applicable)	Exhibit L-01-03
49	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.	Attachment 1 of Exhibit L-01-03
50	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11 - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11 - if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q.	Please refer to Exhibit A-02-03, section 4 re: consultation with embedded distributors and support for allocation of costs. Embedded distributors are part of Hydro One's sub-transmission (ST) rate class, which is included in the cost allocation model (L-01-03-01). Appendix 2-Q is not applicable as embedded distributors are covered by Hydro One's ST class.
51	Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	Not Applicable - Hydro One is not proposing any changes to the methodology in setting rates for unmetered customers in this Application. The most recent change to the level of rates for unmetered customers was related to the adoption of a streetlight allocation factor in 2016.
51	microFIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided	Not Applicable - Hydro One is adopting the OEB's microFIT charge
51	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	Not Applicable - Hydro One is not requesting a standby charge
51 & 52	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	Exhibit L-01-02; restatement of revenue requirement from previous CoS is not applicable as new classes are the result of distributor consolidation
Class Revenue Requirements		
52	To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.	Not Applicable - no proposal to rebalance rates
Revenue to Cost Ratios		
53	If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.	Exhibit L-02-01
53	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	Not Applicable - no proposal to rebalance rates
53	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	Not Applicable - the OEB's Cost Allocation Model was used
EXHIBIT 8 - RATE DESIGN		
54	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Exhibit L-02-01
Fixed Variable Proportion		
54	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V with supporting info -Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast) -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Exhibit L-02-01 Refer to Attachment 2 of L-03-02 for the table comparing different fixed charges.
Rate Design Policy		
55	Applicants that are still transitioning to fully fixed residential rates should refer to the approach to implementation of the policy, including mitigation expectations, was described in a letter from the OEB published on July 16, 2015	Exhibit L-02-01
55	Fully fixed rate design for new charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity. Pass-through costs (e.g. transmission rates, Low Voltage charges, and Group 1 deferral and variance accounts) and LRAMVA amounts are to continue to be recovered as variable charges because the distributor's costs vary with electricity usage. Previously approved distribution-specific charges or rate riders on a distributor's tariff should remain unchanged until they expire, even if they were declared interim.	Exhibits L-02-01 and L-05-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
RTSRs		
55	Retail Transmission Service Rate Work Form - PDF and Excel	Attachment 5 of Exhibit L-02-01 - Hydro One uses its custom model to calculate RTSRs and did not use the OEB's RTSR workform
55	RTSR information must be consistent with working capital allowance calculation; explanation for any differences	Exhibit L-02-01
Retail Service Charges		
55	If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice, and results of consultation	Not Applicable - Hydro One has not proposed changes to RSCs or introduced new rates and charges
56	Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) will dispose of the balances and the RCVAs will be eliminated. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement	Exhibit G-01-01 Attachments 2 and 3 of Exhibit G-01-05
Regulatory Charges		
56	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	Not Applicable - Hydro One is not applying for changes to the generic regulatory charges set by the OEB
Specific Service Charges		
56	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	Please refer to Exhibit L-04-01 Attachment 2 for descriptions of specific service charges. No changes to specific service charges are proposed.
56 & 57	Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group	Not Applicable - Hydro One is not proposing changes to specific service charges
57	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to 2020 and the revenue forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	Exhibit L-04-01
57	Ensure revenue from SSCs corresponds with Operating Revenue evidence	Confirmed; see Exhibit D-02-02 Attachment 1 and Exhibit D-01-01 Attachments 6-10
Wireline Pole Attachment Charge		
58	Record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charge. Distributors will need to refund the closing balance in the distributor's next cost of service application. Distributors may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount and closing the account.	Attachment 3 of Exhibit G-01-05
57 & 58	OEB issued an Order which determined that the inflationary adjustment for 2021 would be suspended. The Order stated that the province-wide pole attachment charge of $44.50 will remain in effect as of January 1, 2021 on an interim basis, until further notice. The Order does not affect any distributor that has an approved distributor-specific wireline pole attachment charge.	Exhibit L-07-02 Attachment 1
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
58	Forecast LV Cost	Not Applicable to Hydro One
58	Actual LV Cost (historical, bridge, test), variances and explanations for substantive changes	Not Applicable to Hydro One
58	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Not Applicable to Hydro One
58	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	Not Applicable to Hydro One
58	Proposed LV rates by customer class	Not Applicable to Hydro One
Smart Meter Entity Charge		
58	Distributor must follow accounting guidance provided on March 23, 2018	Exhibit G-01-01
Loss Factors		
59	Proposed SFLF and Total Loss Factor for test year	Exhibit L-06-02
59	Statement as to whether LDC is embedded including whether fully or partially	Exhibit A-02-03, section 4
59	Study of losses if required by previous decision	Exhibit L-06-02
59	3-5 years of historical loss factor data - Completed Appendix 2-R	Attachment 1 of Exhibit L-06-02 (Appendx 2-R)
59	If proposed loss factor >5%, explanation and action plan to reduce losses going forward	Exhibit L-06-02 and Exhibit B-03-01, s. 3.6.4
59	Explanation of SFLF if not standard	Exhibit L-06-02
Tariff of Rates and Charges		
59	Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - **must be filed in Excel format** Explanation and support of each change in the appropriate section of the application	Exhibits L-07-01 and L-07-02
59	Explanation of changes to terms and conditions of service if changes affect application of rates	Not Applicable - no changes to the Conditions of Service that affect the Application of the rates and charges to be approved by the OEB. Following the OEB's decision on this Application, Hydro One's Conditions of Service will be updated as needed in order to implement the OEB's decision on this Application.
59	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Confirmed; see Exhibit L-07-02 Attachment 1
Revenue Reconciliation		
60	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Attachment 3 of Exhibit L-02-01
60	Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff	Exhibit L-02-01, Attachments 1 and 3

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Bill Impact Information		
60	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Hydro One has filed its custom tariff and bill impacts model in live excel format at Exhibits L-07-02 and L-06-01, respectively.
60	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Attachments 1 to 5 of Exhibit L-06-01
60	Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existi	Exhibit L-02-01 - confirmed that monthly charges have 2 decimals, and variable charges contain 4 decimals
60	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory.	Exhibit L-06-01
61	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	Impacts for multiple consumption levels for all rate classes have been shown in Exhibit L-06-01.
Rate Mitigation		
61	For distributors still in the process of moving to fully fixed residential rates - refer to the approach to implementation of the policy, including mitigation expectations described in a letter from the OEB published on July 16, 2015. Distributors should also refer to the OEB's previous decision approving the extended implementation of fully fixed residential rates.	Exhibit L-02-01
61	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	Exhibit L-06-01 provides proposed mitigation plan and proposed bill impacts.
61 & 62	Rate Harmonization Plans, if applicable - including impact analysis	Exhibits L-01-02 and L-03-01
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
62	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	Exhibit G-01-01
62	Completed DVA continuity schedule for period following last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding deferral and variance accounts. The opening principal amounts as well as the opening interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Attachments 2 and 3 of Exhibit G-01-05 (Hydro One Distribution inclusive of Acquired Utilities)
62	Confirm use of interest rates established by the OEB by month or by quarter for each year	Exhibit G-01-01
62	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the continuity schedule	Exhibit G-01-05 Attachment 2 of Exhibit G-01-05 (Tab: Appendix A)
63	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	Exhibit G-01-02
63	Statement as to any new accounts, and justification.	Exhibit G-01-02
63	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. Distributors to refer to OEB letter of October 2019 in addressing accounting or other errors in respect of Group 1 deferral and variance accounts that have previously been disposed of by the OEB on a final basis. Applicants must provide explanations for the nature and the amounts of adjustments, and include appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts".	Exhibit G-01-01 Exhibit G-01-03
63	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if there are differences between the reported energy sales and cost of power expense	Exhibit G-01-01
63	Completed GA Analysis Workform for each year that has not previously been approved by the OEB for disposition irrespective of whether seeking disposition of the Account 1589 balance as part of current application. If the distributor is adjusting the Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589.	Attachment 1 of G-01-01 (2020 GA Analysis workform)
64	Statement confirming distributor has complied with OEB guidance of February 21, 2019 on the accounting for Accounts 1588 and 1589	Exhibit G-01-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Disposition of Deferral and Variance Accounts		
64	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why	Exhibit G-01-01
65	Statement whether DVA balances before forecasted interest match the last AFS; explain any variances	Exhibit G-01-03
64	If the RRR balances do not agree to the year-end balances in the continuity schedule, a distributor must reconcile and explain the difference(s).	Exhibit G-01-05 Attachment 2 of Exhibit G-01-05 (Tab: Appendix A)
64	For any utility specific accounts requested for disposition (e.g. Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived must be provided. The relevant accounting order must also be provided	Exhibit G-01-01 Relevant accounting orders for utility-specific accounts that have a principal balance to be disposed are filed at Attachment 4 of Exhibit G-01-01
64	Request final disposition of residual balances for vintage Account 1595 sub-accounts only once. Distributors are expected to seek disposition of the audited account balance in the fourth rate year after the expiry of the rate rider. A completed 1595 Analysis Workform for residual balances that meet the eligibility requirements for dispositions of Account 1595 Sub-accounts must be filed	Attachment 1 of Exhibit G-01-03: 1595(2018) Analysis Workform - Norfolk Attachment 2 of Exhibit G-01-03: 1595(2018) Analysis Workform - Woodstock
64	Proposed mechanisms for disposition with all relevant calculations: - allocation of each account (including rationale) - proposed billing determinants, including charge type for recovery purposes - in accrodance with section 2.8.2, and include in cont. schedule	Exhibit L-05-01
64	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation	Exhibit G-01-04
65	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	Exhibits L-05-01 and L-07-02
65	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO	Attachment 2 of Exhibit L-05-01
65	Propose disposition of Account 1592 – PILs and Tax Variances, Sub-account CCA Changes (see 2.4.5.1 of filing	Exhibit G-01-03
Global Adjustment		
66	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	Exhibit L-05-01
66	GA Analysis Workform in live Excel format for each year that has not previously been approved by the OEB for disposition (on an interim or final basis), irrespective of whether or not seeking disposition of Group 1 deferral and variance account balances. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589	Attachment 1 of Exhibit G-01-01 (2020 GA Analysis Workform)
66	As part of Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences pertaining to factors such as true-ups between estimated and actual costs and/or revenues. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition of the balance is approved. Any unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Attachment 1 of Exhibit G-01-01 (2020 GA Analysis Workform)
66	To further support a conclusion that GA charges have been appropriately allocated between customer classes, distributors must also perform a reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	Attachment 1 of Exhibit G-01-01 (2020 GA Analysis Workform)
Commodity Accounts 1588 and 1589		
67	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, it must indicate this	Not Applicable; Hydro One has implemented the Accounting Guidance as noted in Exhibit G-01-01
67	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, distributors should indicate the year in which balances were last disposed on a final basis.	Exhibit G-01-03
67	In order to request for final disposition of historical balances as part of the current application, distributors must provide confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Distributors must also discuss the results of the review, whether any systemic issues were noted, and whether any material adjustments to those balances have been recorded. A summary and description of each adjustment made to the historical balances must also be provided in the application.	Exhibit G-01-01
67 & 68	Expectations of final disposition requests of commodity pass-through account balances are: - Interim disposition of historical balances or no disposition requested: some distributors may have received approval for interim disposition of historical account balances or did not request disposition of account balances in a prior rate application due to the threshold test. If these distributors have reviewed the balances in the context of the new accounting guidance and are confident that there are no systemic issues with their RPP settlement and related accounting processes, distributors may request final disposition of account balances. If these distributors identified errors or discrepancies that materially affect the ending account balances, utilities should adjust their account balances prior to requesting final disposition - No disposition of historical balacnes and concerns noted: distributors that did not receive approval for disposition of historical account balances due to concerns noted by the OEB should apply the accounting guidance to those balances and adjust the balances as necessary, prior to requesting final disposition.	Not Applicable; Hydro One is requesting final disposition of its outstanding account balances. All previously approved balances were disposed of on a final basis.
68	If accounting guidance not fully implemented effective January 1, 2019, a distributor must provide an explanation as to why this guidance has not been implemented, the status of the implementation process, and the expected implementation date.	Not Applicable; Hydro One has implemented the Accounting Guidance as noted in Exhibit G-01-01
68	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	Attachment 2 of Exhibit G-01-01

2022 Cost of Service Checklist

Hydro One Networks Inc. (Distribution)

EB-2021-0110

Date: August 5, 2021

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Disposition of CBR Class B Variance		
68 & 69	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. In the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance - The DVA continuity schedule will allocate the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	Exhibit L-05-01 (current proposal is to dispose of over 5 years). Account 1580 sub-account CBR Class B is rolled into Account 1580 - WMC control account, since it results in $0.0000 rate rider for one or more class
Disposition of Account 1595		
69	Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year only once, on a final basis	Exhibit G-01-01
70	Account 1595 Analysis Workform - live Excel - for distributors who meet the eligibility requirements for disposition of residual balances of Account 1595 sub-accounts	Attachment 1 of G-01-03: 1595(2018) Analysis Workform - Norfolk Attachment 2 of G-01-03: 1595(2018) Analysis Workform - Woodstock
70	Reconciliation of 1595 residual balance with any amounts that have yet to result in associated rate riders (for example, shared tax savings amounts that were previously approved to be transferred to Account 1595 for disposition at a later date).	Not Applicable - Hydro One does not have any balances that have yet to result in associated rate riders
70	Material residual balances wil require further analysis, consisting of separating the components of the residual balances by each applicable rate rider and by customer rate class. Detailed explanations for any significant residual balances attributable to specific rate riders for each customer rate class. Explanations must include for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed.	Attachment 1 of Exhibit G-01-03: 1595(2018) Analysis Workform - Norfolk
Retail Service Charges		
70 & 71	Retail Service Charges - if there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances - state whether Article 490 of APH has been followed; explanation if not followed	Exhibit G-01-01
71	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account would be refunded to ratepayers in a future rate application, and the new account subsequently closed. Distributors can forecast a balance up to the effective date of new rates and the OEB may consider disposing of the forecasted amount	Not Applicable - Hydro One has used its current RCVA to dispose of its remaining balances
Establishment of New Deferral and Variance Accounts		
71	New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order.	Exhibit G-01-02 Attachments to Exhibit G-01-02

Updates to Conditions of Service

Hydro One's Conditions of Service document describes how the company will conduct business with our Customers, and the terms of services provided. We have recently updated our Conditions of Service to address clarity, incorporate new initiatives, and updates to corporate practice. The entire document has also been streamlined for ease of use and readability.

The following is a summary of the key changes to Hydro One's Conditions of Service and where to find the updates in the document.

Old Section	New Section	Section Title	Summary of Key Changes
1.3		Interpretation	This section has been updated to include the interpretation of "prompt" and "promptly", and "meter read or reading" has been removed because it is a defined term in the glossary.
1.4		Amendments and Changes	This section has been updated to include Local Distribution Companies.
1.6.A.- K	1.6.1 - 1.6.12	Customer Rights and Obligations	This section has been reordered and renumbered.
1.6.A	1.6.1	Accuracy of Information	Include purchase and lease agreements.
1.6.D.	1.6.12	Tree and Vegetation Management	This section has been updated to include details on clearances between trees and power lines.
1.6.E.	1.6.4	Temporary Disconnect	The title has been changed for clarity from "No Charge Outage for Upgrade or Maintenance of Customer Equipment for Safety Reasons".
	1.6.11 (New)	Acquired Facilities and Equipment	This section has been added to address Hydro One acquired Facilities and Equipment detailing acquired Customer rights and obligations with respect to acquired facilities and equipment.
1.7.A.- C	1.7.1 – 1.7.3	Hydro One's Distributor Rights and Obligations	This section has been renumbered
1.7. B	1.7.2	Tree and Vegetation Management and Removal of Obstructions	This section has been updated for clarity and to reflect current practices.
1.8		Disputes	This section has been updated to outline the dispute process and to include contact information for the office of the Hydro One Ombudsman.
1.11.		Coming Into Force	This section has been deleted as the information is included on the cover.
2.A.B.	Appendix B	Cable Locates, Fault Locates and Repairs	This section has been updated to reflect current practices and reordered to the appendix.
2.C.	2.3.2 F	Motors and Welders	This section has been moved to the power quality section within section 2.
2.1.C.		Temporary Connections	This section has been updated to reflect current practices on cost responsibility between Hydro One and the Customers.
2.1.D,E, F	3.3,3.6,3.4	Service to Sub-transmission Customers, Embedded Distributor, Embedded Generation Facility.	This section has been deleted and relevant information has been moved to the rate class specific sections.
2.1.G,H.	2.3.7. F,C	Central Metered Service Primary Metered Services	This section has been updated to reflect current process and moved to section 2.3.7, Metering Installation and Meter Reading.

2.1.I,J,K	Appendix F	Mobile Home Parks, Travel Trailer Parks and Campgrounds, Existing Parks	This section has been revised to break out requirements for new and existing customers, updated to reflect current practices and relocated to Appendix F.
2.1.L-S	2.1.D-K	Various	This section sequence has been reordered.
2.1.O	2.1.G	Transformation – Overhead Transformation	This section has been updated to reference that Customer's may be entitled to a Customer-supplied transformation allowance.
2.1.R.	2.1.J	Transformation – Additional Station Transformation	This section has been updated to reflect current practices.
2.1.2, 2.1.2 A	2.1.2	Expansions/Offer to Connect	Information has been revised to reflect the Distribution System Code amendments for this section.
2.1.2 B - 2.1.2 G	2.1.2.1 – 2.1.2.5	Various	This section has been renumbered.
2.1.2.E.4 .2	2.1.2.4.D .2	Lines on Private Property	This section has been updated to clarify Customer responsibilities.
2.1.2.E.4 .6	2.1.2.4.D .6	Submarine Cable	This section has been updated to clarify that Hydro One owns all submarine cable unless it only feeds a single Customer.
2.1.2.F,G	2.1.2.6	Rebates	Information has been revised to reflect the Distribution System Code amendments for this section.
2.1.6. A,B	2.1.6 A-D	Easements	Clarify Hydro One and Customer requirements
2.1.7.A,B		Opening and Closing of Accounts/Implied Contracts	This section has been updated to remove outdated information and reorganized for clarity.
2.1.7.E.		Multi-Service Developments	Information has been revised to reflect the Distribution System Code amendments for this section.
2.1.7.J.		Special Contracts	This section has been updated to include contracts for 'connections requiring upstream (transmission or Host Distributor) upgrades'.
2.1.8.		Bypass of Distribution Facilities	Information has been revised to reflect the Distribution System Code amendments for this section.
3.7	2.1.9.	Load Capacity on a distribution facility	This section has been updated to reflect current practices and its sequence has been reordered. Relocated content from section 3.7: ▪ Total Normal Supply Capacity (3.7.G.1.) ▪ Assigned Capacity (New) ▪ Historical Capacity (3.7.G.2) ▪ Determination (3.7.G.2.1) – Revised wording from Embedded Distributor to Customer ▪ Load Manipulation (3.7.G.2.2.) ▪ Notification (3.7.G.2.3.) ▪ Contracted Capacity (New) ▪ Available Capacity (3.7.G.3.) ▪ Cancellation of Assigned Capacity (3.7.G.3.3.)
	2.1.10.	Cost Responsibility for Investments in Transmission Facilities	Information has been revised to reflect the Distribution System Code amendments for this section.
2.2.		Disconnection/Load Control	This section has been updated to include 'failure to setup a new account after moving in to a vacant premises'.
2.2.A-J	2.2.1- 2.2.10	Disconnection/Load Control	This section has been renumbered.
2.2.G.	2.2.7	Disconnection and Reconnection Related Charges	This section has been updated to reflect current practice and clarify cases when charges apply i.e. for disconnections and reconnections done remotely.

2.2.H.	2.2.8	Unauthorized Energy Use	This section has been updated to include clarification on cost responsibility between Hydro One and the Customer along with Hydro One's ability to notify listed entities, as appropriate.
2.3.2 G.		Stray, Tingle, or Animal Contact Voltage	This section has been updated to reflect current process and reference section 4.7 and appendix H of the Distribution System Code.
	2.3.2 I.1 (New)	Vital Services	This section has been added to cover planned outage notification for customers on the vital services list.
2.3.6.A.		Emergency Backup Generation	This section has been updated to reflect current practice and Energy Storage Facilities information has been relocated to 2.3.6.B.
2.3.6.B.		Load Displacement Generation Facilities	This section has been updated to reflect current practice and to include Energy Storage Facilities relocated from section 2.3.6.A
2.3.7.1.B ,C		Single Phase – Secondary Metered, Three Phase – Secondary Metered	This section has been combined and updated to clarify Customer metering details.
2.3.7.1 D-J	2.3.7.1 C-I	Various	This section has been renumbered.
2.3.7.1.D	2.3.7.1.C	Primary Metered	This section has been updated for clarity on primary metering requirements and cases for customers with non-standard secondary voltages.
2.3.7.1.F	2.3.7.1.E	Totalized Metering	This section has been updated to include metering details specific to the Sub-Transmission and General Service rate classification.
2.3.7.1.H	2.3.7.1.F	Central Metering	This section has been updated to reflect current practice.
2.3.7.2		Instrument Transformer Enclosure	This section has been updated to reflect current practice on requirements and the title has been revised from 'Current Transformer Box'.
2.3.7.3.A		Conditions for Supplying Interval Metering	This section has been updated to reflect current practice and reference to section 2.4.4.K, Annual Monitoring of Electricity Usage.
2.3.7.3.C .		Smart Metering	This section has been updated to reflect Hydro One's regulatory exemption (for certain hard to reach Customers) from deployment of smart meters and time-of-use rates and includes the use of metering with remote disconnect and reconnect capabilities.
2.4.1.4		Rate Schedules and Notice of Rate Changes	The standard set of rate classifications no longer applies so this paragraph has been removed from this section.
2.4.2.B.		Pricing of Standard Supply Service, including RPP	This section has been revised for clarity.
2.4.3 A-J	2.4.3 A-I	Various	This section has been updated to reflect current policies, streamlined for Customer readability and its sequence has been reordered.
2.4.4.C.		Use of Estimates	This section has been updated to clarify process on use of estimates if there is no historical usage available.
2.4.4.F.		Budget Billing	This section has been updated to add a statement on the regulatory requirements and clarify Customer eligibility.
2.4.4.G.		Billing Errors: Over and Under Billing	This section was updated to reflect current practices including estimated reads as part of standard billing practices, payment requirements and to clarify time periods.
2.4.4.K.		Annual Monitoring of Electricity Usage	This section was updated to reflect current practices.
	2.4.5. (New)	Gross Load Billing	This section has been added to Hydro One's Conditions of Service.

2.4.5	2.4.6	Payments and Overdue Account Interest Charges	This section has been renumbered
2.4.6.A.	2.4.7.A	Arrears Management Program – Residential Customer	This section has been updated to reflect current practice.
2.5		Various	This section has been renumbered.
2.5.B.	2.5.2	Protection of Individual Privacy and Consumer Information	This section has been updated for clarity
3.1.A-H	3.1.1-3.1.8	Residential (Various)	This section has been renumbered
3.1.B		Farm	This section has been removed from Hydro One's Conditions of Service as rate classifications were harmonized Jan 1, 2011.
3.2.A-F	3.2.1-3.2.4	General Service (Below and Above 50 kW) – Various	This section has been renumbered
3.2.F.	3.2.4	Metering	This section has been revised to decrease the threshold from 200kW to 50kW and reflect current practice.
3.3		General Service	This section has been deleted. Service requirements for both General Service (Below 50 kW) and General Service (Above 50 kW) Customers are covered under Section 3.2.
3.4 3.4 A-D	3.3	Sub-Transmission	This section has been renumbered to follow sequence and updated to reflect current practice.
3.4.D.	3.3.4	Metering	This section has been updated to reflect current practice for Customer requirements.
3.3.5	2.1.10	Upstream Costs	This section has been moved to be included as a sub-section under Section 2.1.
3.5 3.5 A-K	3.4 3.4.1-3.4.11	Embedded Generation Facilities	This section has been renumbered to follow sequence and updated to reflect current practice.
3.5.	3.4	Embedded Generation Facilities	This section has been updated to include net metering as defined by Ontario Regulation 541/05 under the Ontario Energy Board Act.
3.5.C	3.4.3, Appendix E	Connection Process	This section has been streamlined for Customer readability and includes Distribution System Code amendments.
3.5.D.	3.4.4	Connection Agreement	This section has been updated to include details on other potential contracts.
3.5.E.	3.4.5	General Operating Principles, Responsibility for Damages and Consequences of Excess Generation Output.	This section has been updated to reflect current Distribution System Code regulations on capacity and generating electricity.
3.5.I.	3.4.9	Disconnection of a Generation Facility	This section has been updated to include a statement on Maximum Permissible Amount for Delivery and Maximum Permissible Active Power Delivery Amount.
3.5.J.	3.4.10	Cure period for non-financial default	Clarification to current practice for Non-financial defaults as well as the chart in this section has been updated to include impact of default on cases where 'under or not insured' and 'over-generation'.
3.6	3.5	Embedded Wholesale Market Participant	This section has been renumbered to follow sequence
	3.5.1 (New)	Metering-Market Participation Generator	This section has been updated to provide Meter Installation details for Embedded Generators who are Market Participant Generators.
3.7 3.7A-G	3.6, Appendix C	Embedded Distributor	This section has been renumbered to follow sequence. Content from section 3.7 A-G has been updated to remove duplication.

3.7 G.1 – G.4	2.1.9	Load Capacity on a Distribution Facility	This section has been updated and streamlined for Customer readability and relocated to section 2.1.9, under Connections.
3.8	3.7	Unmetered Connections	This section has been renumbered to follow sequence and reordered for Customer readability.
3.8 3.8.1.1, 3.8.2, 3.8.3, 3.8.5	3.7.2, Appendix D	Unmetered Connections	This section has been relocated to Appendix D where Hydro One has created an Unmetered Load Connection Requirements overview.
	3.7.2.B	Sentinel Lights	This section is new to the Conditions of Service.
4.0		Glossary of Terms	New terms added to the Glossary include: “Acquired Customer”, Acquired Distributor”, “Acquired Facilities and Equipment”, “Consumer”, “Customer Connection Horizon”, “End of Life”, “Remote Disconnect Reconnect Meter”, “Standard Offer Program (SOP)” Terms removed from the Glossary include: “MIST”, “MIST Meter”, “MOST”, “MOST Meter” Revision to the Glossary include: “Customer Equipment”, “Force Majeure Event” Acronyms to the Glossary include: Current Transformer (CT), Kilowatt (kW), Kilowatt hour (kWh), Kilovolt amps (kVA), Potential Transformer (PT), Volt (V)
Appendix A		Description of Agreements	This section has been updated for clarity
2.A,B	Appendix B	Underground Locates	This section has been relocated and revised to reflect current practices
3.7	Appendix C	Embedded Distributor Overview	This sections has been relocated and revised to reflect current practices
3.8	Appendix D	Unmetered Connection Requirements Overview	This sections has been relocated and revised to reflect current practices
3.5	Appendix E	Embedded Generation Facilities Connection Requirements Overview	This section has been relocated and revised to reflect current practices. New section added “Embedded Generation Facilities sharing transfer trip/DGEO Path, Devices and Equipment”.
2.1.I,J,K	Appendix F	Mobile Home Parks, Travel Trailer Parks, and Campgrounds	This sections has been relocated and revised to reflect current practices

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 explains the steps Hydro One has taken to address the OEB's direction as part of this Application.

1.0 EB-2017-0049 DISTRIBUTION RATE APPLICATION AND EB-2019-0082 TRANSMISSION RATE APPLICATION

In its decisions in (i) EB-2017-0049 dated March 7, 2019; and (ii) EB-2019-0082 dated April 23, 2020, the OEB provided a number of directions to be addressed by Hydro One in this Application. Hydro One has taken steps to address each of the directions 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-2019-0082	Page	Hydro One Action Items	Evidentiary Reference	Witness
Provide a comparison of its proposed transmission revenue requirement and resulting rates to those of other jurisdictions.	182	Hydro One has undertaken a review based on public information on transmission rate setting in other Canadian provinces in order to provide the requested comparisons.	H-10-01 and H-10-01, Attachment 1	Clement Li
Address identified areas of concern with customer engagement efforts including engaging with end-users, timing considerations.	182	The timing of the customer engagement occurred in advance of and was then integrated with the investment planning process. End-users were consulted in respect of transmission rates.	SPF Section 1.6	Spencer Gill
Review, and provide explanations for the different benchmark cost performance between its transmission and distribution operation.	34	The econometric benchmarking research filed in this Application includes an explanation of why Hydro One's transmission and distribution businesses have different econometric benchmarking results.	A-04-01 Attachment 1, section 4.5	Clearspring Energy Advisors
Provide a summary of monthly reporting of productivity results to the CEO and senior executives as well as reporting on verifiable results.	45 182	This requirement has been satisfied as part of the Hydro One Productivity Exhibit, where a sample monthly report of productivity results to the CEO and senior executives, as well as reporting on verifiable results, are included.	SPF Section 1.4	Joel Jodoin
Engage an independent third party to review and report on its productivity framework as part of the next combined (transmission and distribution) rebasing application.	182	Hydro One engaged Concentric Energy Advisors (Concentric) to conduct an independent third party review of its productivity framework. Concentric's findings on Hydro One's productivity framework are included in the referenced Exhibit.	Attachment 2 of SPF Section 1.4	Joel Jodoin

Address correlation between capital spending and reliability in the next rebasing application.	56	Hydro One Transmission must meet strict reliability standards set by NERC, NPCC and the IESO for normal conditions and contingency conditions. Transmission System Renewal investments are made to preserve the performance of critical assets and thereby meet relevant reliability standards, however because of the redundancy in the transmission system, these investments do not typically have an immediate impact on delivery point reliability statistics. Hydro One has included a section on transmission system reliability in the TSP.	TSP Section 2.4	Bruno Jesus
Initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at the next rate application and fulfill all of the requirements of the settlement proposal on loss reduction.	182	Hydro One Transmission engaged a third-party expert to review its transmission line loss processes with a view to assess the principles and completeness of such processes and identify potential opportunities to cost-effectively reduce transmission line losses. Hydro One has included information on its completion of the transmission line loss settlement and the third party report reviewing its processes in the TSP.	TSP Section 2.3 and 2.6	Robert Reinmuller
Provide a breakdown of proposed capital spending by work category for each test year.	87	Hydro One Transmission has provided a breakdown of the proposed test year capital by work category in the TSP.	TSP Section 2.9 Attachment 1	Bruno Jesus
Demonstrate that its selection process for consultants for future TSPs, or similar matters, is based on a more transparent and competitive process than the approach used to select BCG.	88	Where appropriate, a competitive Request for Proposal (RFP) process was utilized to engage independent experts. SPF Section 1.3 describes this process and provides summaries of the selected experts for third-party reports.	SPF Section 1.3	Various

Provide comparisons for all investments requiring leave to construct (LTC) approvals between what was approved in the LTC applications and what was budgeted into capital expenditures for the test years.	182	Hydro One Transmission has included a table of all investments requiring LTC approval including the approved LTC forecast expenditures and the corresponding TSP forecast expenditures.	TSP Section 2.9	Robert Reinmuller
File a detailed review of its common corporate costs and shared assets allocation methodologies (capital and OM&A) as part of the combined transmission and distribution application due to be filed for 2023 revenue requirement and rates.	183	Black & Veatch (B&V) was engaged to complete the detailed review of Hydro One's common corporate costs and shared assets allocation methodologies. B&V's expert report has been filed in the referenced Exhibit. The findings from the B&V study have informed the overhead capitalization rates, shared asset allocation and common corporate costs allocation.	Exhibit E-04-08, Attachment 1	Joel Jodoin Samir Chhelavda
Provide a report comparing capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America (both under USGAAP and IFRS). The OEB also orders that a detailed review of Hydro One's B&V study regarding overhead capitalization be filed in its next rebasing application. This should include the revenue requirement impact and risk analysis associated with the transition from US GAAP to MIFRS.	183	PwC was engaged to provide a report comparing capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America. B&V was engaged to complete a study regarding overhead capitalization.	Exhibit C-08-02, Attachment 2 Exhibit E-04-08, Attachment 1	Samir Chhelavda
Provide a high level assessment of the correlation, or lack of same, between capital investments and OM&A costs at the program level in future rate applications.	183	Hydro One Transmission has assessed the impact of capital investments on OM&A costs on the basis of its planning and operating experience, as well as by third party analysis.	TSP Section 2.8 Exhibit A-04-01, Attachment 1	Donna Jablonsky Clearspring Energy Advisors, LLC

Explicitly provide compensation costs and associated FTEs, broken down between capital and OM&A and explain any significant differences between percentage changes in compensation costs and FTEs from year to year in future rebasing applications.	183	An updated compensation table has been provided as part of this Application. The compensation table includes the necessary details required by prior OEB decisions, such as compensation costs and associated FTEs broken down between capital and OM&A work programs. Hydro One has also provided explanatory notes to the compensation table.	Exhibit E-06-01, Attachment 2A and 2B	Sabrin Lila
Complete an updated benchmarking study using the same Mercer methodology for the upcoming combined rebasing application as outlined in the Decision and Order.	183	Hydro One has filed an updated benchmarking study using the Mercer methodology as further discussed in the referenced Exhibit.	Exhibit E-06-01, Attachment 1	Sabrin Lila
Include a plan with the next rebasing application to bring compensation levels in line with market median.	183	Hydro One has included a plan to bring compensation levels in line with market median as part of its Corporate Staffing and Compensation Exhibit (Section 5) and the confidential submission in the referenced Exhibits.	Exhibit E-06-01 and Attachment 5 of Exhibit E-06-01	Sabrin Lila
Demonstrate that the 2020 OM&A work program has been delivered and that the compensation reduction has not been achieved by reducing planned work programs	183	Hydro One Transmission has provided information on its 2020 OM&A in the Summary of OM&A Exhibit E-02-01 and the support exhibits in particular Transmission Sustainment OM&A E-02-02, as well as information on the OM&A Program Accomplishment measure in TSP Section 2.5. These exhibits discuss the factors that influenced the 2020 OM&A actual expenditures and accomplishments.	E-02-01 E-02-02 TSP Section 2.5 Sub-section 2.2.3.3	Andrew Spencer Donna Jablonsky
Continue to evolve the methodology for adjusting for CDM in the next application given the concern about Hydro One's use of forecast CDM values for 2016 and 2017 to adjust historical data.	183	Hydro One has evolved its methodology for adjusting for CDM, as described in section 3.1 and 4 of Exhibit D-04-01.	D-04-01	Bijan Alagheband

Provide an ETS study using a cost allocation methodology that includes the allocation of shared network costs to exporters in the next transmission rebasing application as outlined in the Decision and Order.	183	Hydro One has filed a study by Elenchus Research Associates which provides a cost allocation methodology that includes the allocation of shared network costs to exporters.	H-09-01, Attachment 2	Clement Li
File an updated ETS jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications. Hydro One is expected to discuss the approach to a jurisdictional review with the IESO and OEB staff to determine the best approach to complete a review before Hydro One's next transmission rebasing application.	183	Hydro One has filed an updated ETS jurisdictional review conducted by Charles River Associates as well as comments from the IESO regarding how changes to the ETS may impact Ontario's market.	H-09-01 H-09-01, Attachment 3	Clement Li

OEB Decision EB-2017-0049	Page	Hydro One Action Items	Evidentiary Reference	Witness
Explicitly identify, in its next application in which distribution rates are rebased (next rebasing application), initiatives to address reliability challenges experienced in northern communities including economically identified DER solutions.	18	Hydro One has identified initiatives in its system plan that also seek to address the reliability challenges faced by northern communities (including First Nations communities). The initiatives are Energy Storage Solutions (D-SS-04), Worst Performing Feeders (D-SS-05) and Vegetation Management (E-03-02). Details can be found in the respective investment summary documents and in the evidence section. Included as an Appendix, is a report summarizing Hydro One's study of feeders supplying First Nations communities, and it identifies opportunities to improve reliability, which includes economical distributed energy resource (DER) solutions.	A-07-02 Attachment 1	Peter Faltaous
For its next rebasing application, continue with its current benchmarking, and expand it to include other capital programs and administration functions such as billing, call centre and corporate costs.	36	Hydro One continues its benchmarking efforts for key programs. Additionally, Hydro One has completed independent benchmarking studies to compare billing and call center costs, fleet operating costs and common corporate costs to equivalent costs within peer groups.	DSP Section 3.3, GSP Section 4.3, E-04-02-01	Peter Faltaous (DSP Section 3.3); Rob Berardi and Kevin Marcotte (GSP Section 4.3; Joel Jodoin (E-04-02)
File information for vegetation management, pole replacement, station refurbishment and IT, reporting on whether the projected outcomes from each of the benchmarking studies considered in this application have been realized.	36 and 72-73	Outcomes for each of the benchmarking studies have been included in the DSP and GSP. The key findings and recommendations, by benchmarking study report, are listed for the vegetation management, pole replacement and station refurbishment programs in the DSP and for IT in the GSP. Recommendations from studies have been used to assess performance among peer groups and to inform the investment planning process. Study recommendations have also been used to inform the pacing and execution of the vegetation management program.	DSP Section 3.3, GSP Section 4.3	Peter Faltaous Kevin Marcotte

Demonstrate that proposed performance targets are set for each measure and each year, and that they represent an improvement relative to past performance and other benchmarks. Hydro One is to provide detailed reasons for any gaps or exceptions.	48	Hydro One's reporting on its performance targets can be found in the referenced exhibit. The Electricity Distributor Scorecard provided in this exhibit demonstrates Hydro One's success in meeting performance targets, and outlines the performance levels that Hydro One expects to achieve. Additional measures are also included for areas where Hydro One has set targets for improved performance. A discussion on actual results and past performance targets are also presented.	DSP Section 3.5	Bruno Jesus
Clearly describe, in Rebasing Application and future rebasings, the methodology by which any claimed productivity savings are determined and whether those savings represent net cost savings for the company which would translate into reduced cost for the ratepayers.	57	Hydro One has addressed this requirement as part of SPF Section 1.4 – Productivity Framework, taking into consideration input from the independent review study performed by Concentri	SPF Section 1.4	Joel Jodoin
In addition to above, file a report, within twelve months of this Decision and Order, showing the status of the productivity initiatives listed in I-25-Staff-123, including actual savings, with a discussion of any deviation from plan. The report is to be filed on a standalone basis and will not be adjudicated. Hydro One must update the report to file with its next rebasing application.	57	Hydro One has filed the required report as instructed within 12 months of the EB-2017-0049 Decision and Order, showing the status of productivity initiatives listed in I-25-Staff-123. The updated report has been filed as part of the current application in the referenced Exhibit.	SPF Section 1.4, Attachment 1	Joel Jodoin
Demonstrate, in future applications, that OM&A options are being explicitly considered in investment decisions to either replace or defer capital investments, as applicable.	59	Hydro One outlines prioritization of capital investment decisions based on the RSE approach in DSP Section 3.7. Also discussed in DSP Section 3.2 and Exhibit E-03-02 are the condition based factors and other considerations used to inform the decision to replace or defer capital investments, in lieu of some corrective maintenance action.	DSP Section 3.2, DSP Section 3.7, E-03-02	Peter Faltaous

Provide a revised capital investment program as part of its first annual update explaining how the OEB-imposed reductions in this Decision and Order were accommodated in line with the OEB findings. This report is to be filed on a standalone basis to be used as a baseline for future reporting and will not be adjudicated during the annual update rate proceeding.	71-72	As directed by the OEB Hydro One has provided a stand-alone report in support of its revised capital investment program.	EB-2019-0043, 2020 Annual Update (August 30, 2019)	
Submit a comprehensive report with the next rebasing application detailing actual performance in the execution of the capital program relative to plan. More specifically, the report should show the performance at the program level in terms of overall expenditures and in-service additions compared to plan. In addition, for major projects or programs with a total budgeted cost greater than $3 million and which are planned to be completed during the test years, the report should show the status of each project or program and an explanation of any variances regarding scope, cost or schedule. This report follows the same format as the report ordered by the OEB in the EB-2016-0160 proceeding for Hydro One's transmission business.	72	Hydro One has included a comprehensive report detailing actual performance execution of the capital program relative to the plan. The report demonstrates capital performance at the project and program level, with explanations for any material variances.	DSP Section 3.9 Attachment 2, GSP Section 4.9 Attachment 2	CK Ng (DSP Section 3.9); Rob Berardi, Godfrey Holder, and Kevin Marcotte (GSP Section 4.9)

Provision of an assessment of Hydro One's allocation methodology sufficient to allow for a detailed examination of this matter when Hydro One files a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.	79 and 119	Black & Veatch (B&V) was engaged to complete the detailed review of its common corporate costs and shared assets allocation methodologies. The B&V expert report has been filed in the referenced Exhibit.	Exhibit E-04-08, Attachment 1	Joel Jodoin
Filing of a report as part of its next rebasing application that compares Hydro One's capitalization of common corporate costs with those of other utilities in Ontario, Canada and North America. This should include utilities both under US GAAP and those using International Financial Reporting Standard (IFRS). Hydro One may need to disaggregate its corporate costs into separate cost elements in order to do an appropriate comparison.	82	Hydro One engaged PwC to conduct a benchmarking study assessing the capitalization of HONI's common corporate costs relative to other companies both under US GAAP and IFRS in Ontario, Canada and North America.	Exhibit C-08-02, Attachment 2	Samir Chhelavda
Aggressively explore opportunities to improve its performance relative to its peers and report on these improvements, particularly on the introduction of a pole refurbishment program, in its next rebasing application.	72-73	Addressed in Hydro One's DSP under Performance Measurement and Benchmarking; a pole refurbishment program was introduced in 2020.	DSP Section 3.3 DSP Section 3.5	Peter Faltaous C.K Ng Bruno Jesus
For future rate applications, provide justification for the inclusion of any additional pension contributions in rates given the current surplus.	96	Hydro One has addressed this requirement in the referenced Exhibit.	Exhibit E-07-01	Samir Chhelavda

For any future Hydro One rebasing application, develop a consistent template for presenting compensation costs based on the direction provided by the OEB in prior proceedings.	112	For this Application, Hydro One has developed an enhanced excel template to present compensation costs for Transmission and Distribution on a consistent basis to respond to the OEB's concerns raised in prior proceedings.	Exhibit E-06-01, Attachments 2A and 2B	Sabrin Lila
Carry out further investigation on the use of weather data from multiple locations in the province and report back with its next rebasing application.	129	In response to the OEB's direction, Hydro One compared two sets of regression results for annual econometric models, as shown in Appendix B of Exhibit D-05-01. One set is based on using Toronto Pearson International Airport weather data and the other on the average weather data for five weather stations across Ontario, namely, Thunder Bay, Windsor, Toronto, Ottawa, and North Bay.	D-05-01, section 3.2	Bijan Alagheband
Consult with its customers on specific service charges and to report back to the OEB at the time of its next rebasing.	150	Hydro One worked with Innovative Research Group (IRG) to consider the OEB's direction and design an engagement process on specific service charges. IRG carried out the engagement. The results of the engagement are described in IRG's report at L-04-01, Attachment 1.	L-04-01, Attachment 1	Spencer Gill and Clement Li
Update its distribution line loss study for consideration in its next rebasing application, which should include an assessment of the actual line losses for a five-year period.	151	Hydro One assessed the actual line losses for a five-year period and is filing the results of this assessment, which indicates that the anomalous variation that caused the OEB to require an updated study is not present in the previous five-year period.	L-06-02 L-06-02-01	Clement Li and Bijan Alagheband

Place the revenue requirement associated with the forecast cost of the ISOC in an asymmetric variance account to be offset by the revenue requirement at the actual cost. If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will be required to return the difference to its customers. The account balance will be considered for disposition in Hydro One's next rebasing application.	165	Hydro One confirms that this account has been established, and once the ISOC project is placed in service in 2021, Hydro One will evaluate the revenue requirement impact and, if required, return any difference to its customers.	Exhibit G-01-01	Samir Chhelavda
Return 50% of the $121.8 million credit to customers now and the remaining credit when balances are next disposed. The total approved for disposition is therefore a credit of $52.6 million.	167-168	Hydro One returned 50% of the $121.8 million credit to customers at the time of the EB-2017-0049 Draft Rate Order and the remaining balance was included in the disposition of 2019 audited balances in the 2021 Hydro One Distribution Update (EB-2020-0030).	Exhibit G-01-01	Samir Chhelavda
File the necessary evidence regarding the OPEB deferral account in its next rebasing transmission rate proceeding to permit this matter to be determined for both Hydro One's transmission and distribution operations as outlined in the OEB's letter of June 27, 2018	170	The OPEB deferral account matter was resolved as part of the last Transmission Application (EB-2019-0082). In the current application, Hydro One is proposing to dispose of any balances accumulated in the account for both Transmission and Distribution as further discussed in the referenced Exhibit.	Exhibit G-01-01	Samir Chhelavda

Although the OEB agrees with the need to replace these meters, the OEB finds that there is a strong likelihood that Hydro One's plan could result in replacing these meters prematurely. The OEB directs Hydro One to explore with themanufacturer the basis for the estimated service life and any actual data that the manufacturer has to support this assumption before any investments are made in this program, and to include a report of this exploration in its next rebasing application for distribution rates.	75	Trilliant[1] provided Hydro One with correspondence outlining expected service life for meters. The correspondence from Trilliant attests that meters are designed to operate for a period of 15 years, minimum, however goes on to note that actual performance may differ materially from this period and provide no guarantees that the a meter will reach this service life. Additionally, Hydro Quebec was retained to perform accelerated life testing of Hydro One's meters. Hydro Quebec's accelerated life testing model results in projections of approximately 45% of the total fleet or 579,000 meters failing through 2027 (DSP Section 3.11, D-SR-12).	DSP Section 3.3 and DSP Section 3.3, Attachment 4 and Attachment 5	David Paish

[1] Trilliant is Hydro One's primary AMI 1.0 Vendor, providing almost 95% of Hydro One's meter fleet and 100% of collectors and repeaters (DSP Section 3.11, D-SR-12).

This page left blank intentionally.

EXECUTIVE SUMMARY

This application is for approval of Hydro One Networks Inc.'s (Hydro One or the Company) rates under a Custom Incentive Rate-Setting (Custom IR) framework, for a five-year test period commencing January 1, 2023 and ending December 31, 2027, for each of its Transmission business and its Distribution business (the Application). This is Hydro One's first joint application for the Transmission and Distribution businesses.[1]

Hydro One's proposed revenue requirement for the 2023 test year has been determined for each of the Transmission and Distribution businesses using a cost of service approach. The Transmission and Distribution revenue requirements for 2024-2027 will be determined formulaically using a proposed Custom IR model, with parameters specific to each business. Hydro One is requesting to recover its proposed Transmission revenue requirement through an amendment to Uniform Transmission Rates (UTRs), and its proposed Distribution revenue requirement through approval of distribution rates and charges as set out in this Application.

This exhibit provides an overview of the key aspects of the Application, as follows:

- Section 1 – Scope of the Application, including the relief requested
- Section 2 – Overview of Hydro One's business
- Section 3 – 2023-2027 Business Plan
- Section 4 – Customer engagement
- Section 5 – Productivity framework
- Section 6 – OM&A expenses
- Section 7 – 2023-2027 Transmission, Distribution, and General Plant System Plans (individually, the TSP, DSP or GSP), which provide the basis for planned Transmission, Distribution and General Plant capital expenditures

---

[1] Commonly used words or phrases are defined in the Glossary in Exhibit A-02-02.

- Section 8 – Performance measurement and independent expert studies
- Section 9 – Key financial components, including revenue requirement, rate base, cost of capital, and deferral and variance accounts
- Section 10 – Custom IR proposal
- Section 11 – Load forecast
- Section 12 – Cost allocation and rate design
- Section 13 – Bill impacts
- Section 14 – Conclusions

As the Application shows, Hydro One has – through a set of robust planning processes – developed 2023-2027 System Plans that are responsive to pressing system/asset needs and customer preferences. Further, the proposed 2023 OM&A expenditures reflect Hydro One's commitment to ongoing cost control and productivity savings. Given its demonstrated ability to execute large and complex work portfolios, Hydro One is confident that it can deliver the proposed plans, which benefit customers and have a reasonable rate impact.

- **Planning Framework** – As highlighted in Sections 7.1 to 7.3 below, Hydro One employs rigorous asset management and investment planning processes – in conjunction with comprehensive customer engagement – that are designed to identify and target key investment needs, drive customer-oriented outcomes, and mobilize an enterprise-wide approach to fact-based decision making. In particular, the choices and trade-offs that led to the final plans are backed by data related to system and asset needs (including equipment condition and performance in the field) and the risk mitigation impact of investment solutions on outcomes valued by customers. In this manner, Hydro One was able to evaluate, compare and consolidate investments across a range of functions and asset categories, while maintaining consistency and rigor in the underlying criteria and processes.
- **Transmission Capital Plan** – Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital, for a total of $7,258M. System Renewal investments (accounting for 82% of this total) are required to address assets

that pose significant reliability, safety and/or environmental risks – including large populations of network and connection station assets that are in poor condition, obsolete or inadequately performing as well as transmission conductors and line components that are in poor condition. System Service and System Access investments (10% of the total) are required to meet mandatory service and planning obligations, including regional infrastructure needs to alleviate system constraints and accommodate load growth (e.g., in Windsor-Essex, where electricity demand is expected to double in the next 5 years).[2]

- **Distribution Capital Plan** – From 2023 to 2027, Hydro One plans to invest an average of $1,059M a year in Distribution capital, for a total of $5,297M. System Renewal investments (43% of this total) will address poor condition assets (including a subset of poor condition poles, line sections and station assets that pose significant reliability risk) as well as various non-discretionary needs. In fact, the majority of System Renewal expenditures pertain to mandatory or demand drivers, including the replacement of failing or failed station assets, trouble calls/storm response, polychlorinated biphenyl (PCB) equipment phase-out, and replacement of the legacy Advanced Metering Infrastructure 1.0 system (as meters reach end of service life, experience increasing failures, and lead to adverse compliance and service impact). System Access (21% of the total) responds to mandatory regulatory or service obligations, such as new connections and the sustainment of existing metering infrastructure. System Service (19% of the total) includes, among other things, grid modernization and battery storage projects to improve reliability for customers and communities that suffer from poor reliability of service (consistent with customer preference for accelerated spending in these areas).[3]
- **Transmission OM&A** – Hydro One proposes a Transmission OM&A budget of $420.5M for 2023 to meet public and employee safety objectives, maintain transmission system reliability, and comply with regulatory requirements. Notwithstanding incremental

[2] The remaining 8% of the proposed TSP are attributable to General Plant investments.
[3] The remaining 17% of the proposed DSP are attributable to General Plant investments.

needs for 2023 (i.e., to address deferred station maintenance, security risks, and overhead corrective maintenance), the proposed 2023 budget represents a little more than an inflationary increase over the 2020 to 2023 period. This is largely a result of Hydro One's ongoing commitment to achieving productivity savings and sustained cost control.

- **Distribution OM&A** – Hydro One proposes a Distribution OM&A budget of $597.5M for 2023 to meet public and employee safety objectives, maintain distribution system reliability, and comply with regulatory requirements. This budget represents a less than inflationary increase over the period from 2018 to 2023. In fact, when the proposed total is normalized (i.e., excluding non-service costs component of Other Post-Employment Benefits (OPEBs) and OM&A for the former Norfolk Power, Haldimand County Hydro and Woodstock Hydro (the Acquired Utilities) on the same basis as the amounts approved in the prior distribution application, the equivalent 2023 amount is $36.4M (or 6.1%) lower than the 2018 approved OM&A escalated by inflation. This is a result of Hydro One's cost control initiatives and productivity savings.[4]
- **Historical Performance** – Hydro One has demonstrated its ability to deliver sizeable work programs and achieve strong performance results, including as reported through various Transmission and Distribution scorecards (see TSP Section 2.5 and DSP Section 3.5), assessed by independent studies that compare Hydro One's performance against peer utilities or its own past performance (see TSP Section 2.3 and DSP Section 3.3), and evidenced by a track record of delivering its large and complex work portfolios within or close to approved expenditures levels (see TSP Section 2.9 and DSP Section 3.9). For the 2023-2027 plan, Hydro One remains committed to measuring and tracking its

[4] Notably, Hydro One Distribution's ability to manage OM&A costs in recent years has been recognized in the industry, including in a June 15, 2021 C.D. Howe Institute report that noted: "While other LDCs saw their average administrative expense per customer rise 5% from $158 per customer in 2014 to $166 per customer in 2019, Hydro One's fell by 36% from $244 per customer to $155 per customer over the same period." (see https://www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/e-brief_316_0.pdf, p. 6).

performance to ensure that its plans are efficiently and successfully executed to realize outcomes that benefit customers.

- **Rate Impact** – The proposed capital plans and OM&A expenditures entail revenue requirements and rate impacts that are reasonable relative to the significant value provided to ratepayers through efficient, safe and reliable operations. On a combined Transmission and Distribution basis, the estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) is a decrease of 2.1% ($3.20) in 2023 and an average annual increase of 1.1% ($1.68) over the Application period. The estimated total monthly bill impact for a typical Hydro One GSe< 50 kW customer (2,000 kWh/month) is a decrease of 2.2% ($9.22) in 2023 and an average annual increase of 0.9% ($3.75) over the Application period.

1.0 SCOPE OF THE APPLICATION

On March 16, 2018, the Ontario Energy Board (OEB) issued a letter directing Hydro One to file a single application for distribution rates and transmission revenue requirement for a test period commencing in 2023.[5] This Application responds to the OEB's direction by seeking approval for distribution rates and transmission revenue requirement for Hydro One's Distribution business and Transmission business, respectively, for the period 2023-2027. Hydro One's Distribution business is currently governed by a Rate Order (EB-2017-0049) for the period 2018-2022. Hydro One's Transmission business is currently governed by a Rate Order (EB-2019-0082) for the period 2020-2022. The System Plans comply with the OEB's Filing Requirements for Electricity Distribution Rate Applications Chapters 2 and 5 (June 24, 2021) and the OEB's Filing Requirements for Electricity Transmission Applications (February 11, 2016), as applicable (collectively, the Filing Requirements).

---

[5] See https://www.rds.oeb.ca/CMWebDrawer/Record/602425/File/document and https://www.rds.oeb.ca/CMWebDrawer/Record/648487/File/document, which provide the OEB's original direction on filing a joint rate application and its subsequent confirmation that the joint rate application should not include Hydro One Remote Communities Inc. as originally contemplated.

This Application includes Hydro One's five-year TSP, DSP and GSP. These are accompanied by a System Plan Framework (SPF) that includes elements that are common to all three plans (together with the TSP, DSP and GSP, the System Plans). The System Plans are responsive to the OEB's direction to apply for rates and revenue requirement for the Distribution and Transmission business segments in a single application. Although there are common elements to the System Plans, such as the customer engagement process, the investment planning process and the productivity framework, the majority of the plans reflect the unique and distinct nature of the Transmission and Distribution businesses through the TSP and DSP. General Plant assets, which are shared between Transmission and Distribution, are reflected in the GSP.

Consistent with the Filing Requirements and using a standardized approach and structure, the System Plans provide a consolidated set of documentation about Hydro One's asset management process and capital expenditure plans for its transmission and distribution systems and common support infrastructure. The System Plans also provide related information about the steps Hydro One has taken to coordinate its planning with third parties, identify and take into account customer needs and preferences, as well as measure performance to support continuous improvement.

In this Application, Hydro One is requesting the OEB's approval for, among other things, a transmission rates revenue requirement of $1,763.3M for 2023 and base distribution revenue requirement of $1,586.0M for 2023.[6] Further details about Hydro One's requested relief are included in Exhibit A-02-01. Approval of this Application results in the following bill impacts:

[6] This Application does not include the former Orillia Power Distribution Corporation service area, the former Peterborough Distribution Inc. service area, Hydro One Sault Ste. Marie LP or transmission lines projects that are expected to be owned by and included in the rate base of new transmission-licenced partnerships (which projects are being addressed in a separate application to the OEB to establish a deferral account (EB-2021-0169); see further details at Exhibit A-07-02 and TSP Section 2.8).

Table 1 - Illustrative Combined Bill Impacts of the Proposed Changes in Transmission and Distribution Revenue Requirements[7]

Rate Class	Monthly Consumption (kWh)		2023		2024		2025		2026		2027		5-year average	
			Change in Total Bill ($)	Change in Total Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1 (without DRP)	750	DX Impact*	($2.78)	-1.8%	$1.40	0.9%	$2.36	1.5%	$3.18	2.0%	$2.26	1.4%	$1.29	0.8%
		TX Impact**	($0.43)	-0.3%	$0.49	0.4%	$0.61	0.5%	$0.77	0.6%	$0.52	0.4%	$0.39	0.3%
		Combined Impact	($3.20)	-2.1%	$1.89	1.3%	$2.97	2.0%	$3.95	2.6%	$2.78	1.8%	$1.68	1.1%
GSe	2,000	DX Impact*	($8.32)	-2.0%	$1.43	0.4%	$6.12	1.5%	$8.38	2.0%	$6.99	1.7%	$2.92	0.7%
		TX Impact**	($0.90)	-0.2%	$1.03	0.3%	$1.30	0.3%	$1.62	0.4%	$1.11	0.3%	$0.83	0.2%
		Combined Impact	($9.22)	-2.2%	$2.46	0.7%	$7.42	1.8%	$10.00	2.4%	$8.10	2.0%	$3.75	0.9%

** Distribution (DX) Impacts shown here can be found in Tables 1 to 5 of Exhibit L-6-1*
*** Transmission (TX) Impacts shown here can be found in Tables 3 and 4 of Exhibit H-10-1*

On a Transmission only basis, the estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) is a decrease of 0.3% ($0.43) in 2023 and an average annual increase of 0.3% ($0.39) on monthly bills over the Application period. For a typical Hydro One GSe< 50 kW customer (2,000 kWh/month), the estimated total monthly bill impact is a decrease of 0.2% ($0.90) in 2023 and an average annual increase of 0.2% ($0.83) on monthly bills over the Application period.

The average bill impact of the Transmission portion of this Application for a transmission-connected customer is a decrease of 0.2% in 2023 and an average annual increase of 0.2% over the Application period, as detailed in Section 13.1, below.

On a Distribution only basis, the estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) is a decrease of 1.8% ($2.78) in 2023 and an average annual increase of 0.8% ($1.29) on monthly bills over the Application period. For a typical Hydro One GSe< 50 kW customer (2,000 kWh/month), the estimated total

[7] Bill impacts shown in this table are for illustrative purpose only. In reality, there typically is a lag between when the approved Uniform Transmission Rates (UTRs) are reflected in the RTSRs for distribution customers. For example, Hydro One's approved 2021 RTSRs are based on 2020 Interim UTRs.

monthly bill impact is a decrease of 2.0% ($8.32) in 2023 and an average annual increase of 0.7% ($2.92) on monthly bills over the Application period.

2.0 OVERVIEW OF HYDRO ONE'S BUSINESS

Hydro One carries on the business of owning and operating electricity transmission and distribution facilities in Ontario pursuant to licenses (ET-2003-0035 and ED-2003-0043) from the OEB. Hydro One is an indirect subsidiary of Hydro One Ltd., which is publicly traded on the Toronto Stock Exchange (H). Hydro One uses US GAAP as its basis of accounting for both financial and regulatory purposes.[8]

The Transmission and Distribution businesses of Hydro One are two fundamentally different regulated businesses from the perspective of functions, operations, customers and customer needs. Although each business relies upon shared resources such as employees and a fleet of general plant assets (including real estate and facilities, transport and work equipment, as well as information and operating technology), which are critical to each business' function and reliability, the system planning, operations and maintenance activities of each business must be conducted separately.

Hydro One's transmission grid is 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 291 transmission stations and approximately 29,000 circuit-kilometers of high-

---

[8] As discussed in Exhibit A-06-01, the OEB has stated that the continued use of US GAAP for regulatory purposes is to be considered as part of the current joint rate application and that Hydro One is required to provide certain analysis on this issue. Based on Hydro One's evaluation, supported by analysis from PricewaterhouseCoopers LLP, it has determined that there are no significant benefits to be gained by transitioning to IFRS, that even if there were significant benefits to transitioning it would be premature to do so given the ongoing uncertainty regarding the timing and substance of final standards, and that maintaining the use of US GAAP would avoid disruption to the business and avoid costs for ratepayers and the utility.

voltage lines and towers operating at 500 kV, 230 kV or 115 kV. Hydro One’s system transmits electricity from generation sources to load customers, including 38 local distribution companies (LDCs), Hydro One’s own distribution system, and 83 large industrial customers that are directly connected to the transmission system. In addition, Hydro One’s transmission system enables the operation of all other licensed transmission systems in Ontario, including Canadian Niagara Power Inc., Five Nations Energy Inc., Hydro One Sault Ste. Marie LP, Niagara Reinforcement Project Limited Partnership, and B2M Limited Partnership. It is also linked to five jurisdictions adjacent to Ontario through 25 high-voltage interconnections.

Hydro One’s distribution system delivers electricity at voltages below 50 kV from the transmission system to its end-use customers, which consist of approximately 1.4M predominantly rural Residential and Small Business customers. The distribution system also delivers electricity to Commercial & Industrial customers, Embedded Local Distribution Companies and other Large Distribution Account customers, and delivers electricity from distribution-connected generation facilities. The distribution system employs more than 123,000 km of distribution circuits, spanning a vast area of the province with varying customer densities and regional needs such as forestry, weather patterns, and load growth.

Hydro One prioritizes transmission and distribution system investments separately for each of these business segments, consistent with Transmission and Distribution having discrete drivers and considerations that inform and underpin the System Plans, separate OEB licenses and rate approvals, distinct customers, and separate revenue requirements. Common general plant investments are allocated, based on the methodology established in the Black & Veatch shared asset allocation study (See Exhibit C-03-01), and are included within each segment based on business drivers.

3.0 HYDRO ONE'S BUSINESS PLAN

Hydro One's 2023-2027 Business Plan supports Hydro One's strategic objectives, which are outcomes-driven, customer-centred and aligned with the OEB's Renewed Regulatory Framework for Electricity (RRF). The Business Plan process is a robust exercise that is typically conducted annually. The 2023-2027 Business Plan, which underpins the proposed funding framework and levels in this Application, was approved by Hydro One's Board of Directors in May 2021. Hydro One's fully integrated business planning process incorporates investment planning, business planning (including resource planning), regulatory, and customer engagement processes. In particular, Hydro One ensured that the results of its two-phase customer engagement were appropriately considered and reflected, as further discussed in Section 4.0 below and Sections 1.6 and 1.7 of the SPF.

The sections that follow further discuss the key inputs and considerations that informed the 2023-2027 Business Plan, including customer engagement (Section 4.0), productivity savings (Section 5.0), and performance measurement and third party expert studies (Section 8.0).

A full copy of Hydro One's 2023-2027 Business Plan is provided as Attachment 1 to this Exhibit.

4.0 CUSTOMER ENGAGEMENT

Hydro One undertook a number of customer engagement activities through which it gained a clear understanding of the needs and preferences of its Distribution and Transmission customers, and of the outcomes that are of greatest value to them. This understanding, and underlying customer feedback, has been integrated into Hydro One's investment planning process.

In 2019, Hydro One engaged an independent third party research and consultation firm (Innovative Research Group – IRG) to develop and conduct a comprehensive customer engagement study for purposes of this joint rate application. In conducting the study over the course of 2019 and 2020, IRG employed a two-phased approach that gave all customers the opportunity to participate and provide feedback that was taken into account in Hydro One's investment planning process, as discussed in Section 7.3 below and detailed in SPF Sections 1.6 and 1.7. This is the most comprehensive customer engagement Hydro One has ever undertaken, collecting input from more customers than any other similar engagement in Ontario to-date (to Hydro One's knowledge). In total, over 48,000 customers participated in this study through various types of activities, including focus groups, in-depth interviews, telephone surveys, and online workbooks.[9] The activities also included conversations with First Nations, the Métis Nation of Ontario, Municipalities and Other Stakeholders.

The proposed investment plans are closely aligned with customer needs and preferences. The results of the IRG study indicate strong customer support for the draft plans – customers across all segments support the investments in the plans and are willing to accept bill increases in return for these investments.[10] Throughout both phases of the study, customers sent a clear message that they expect Hydro One to be a good steward of the electricity system in Ontario and make the investments necessary to maintain the system for future generations.[11] Customers are in favour of replacing distribution and transmission assets when or before they deteriorate and are willing to pay more for investments that improve reliability or the overall health of the system.[12] Customers see value in investing in grid modernization and support technology investments that reduce costs, improve reliability, and help customers manage electricity usage.[13] Feedback from the customer engagement study was integrated directly into the development, and then finalization, of the investment plans.

In addition to the IRG customer engagement study, Hydro One regularly engages with its customers in various other ways. Additional customer feedback received through other forms of

---

[9] IRG Report p. 25
[10] IRG Report p. 26
[11] IRG Report p. 26
[12] IRG Report p. 5
[13] IRG Report p. 5

engagement was also taken into account in, and helped inform, the investment planning process. These other forms of engagement include in-depth conversations with (and input received from) large customers through the Account Executive Program, as well as engagements with First Nations communities and municipalities. Other activities, such as customer satisfaction research, conversations with customer service representatives in its contact centers, and regular dialogue with industry stakeholders and consumer groups inform Hydro One's business on an ongoing basis.

In respect of Indigenous Relations, for over ten years Hydro One has engaged, and continues to engage, with First Nations and Métis communities through ongoing relationship building efforts. Hydro One seeks input from First Nations and Métis to understand their specific customer needs and preferences with respect to its distribution and transmission systems.

Further details regarding Hydro One's customer engagement activities are provided in SPF Section 1.6 and the attachments to that exhibit. Further details relating to Hydro One's First Nations and Métis Relations Strategy are provided in Exhibit A-07-02.

5.0 PRODUCTIVITY FRAMEWORK

Hydro One's commitment to achieving incremental and continuous productivity improvements is central to the planning and execution of work programs across the Company. In this regard, and to further its commitment to delivering outcomes that are valued by its customers, Hydro One continues to execute its comprehensive and rigorous process for productivity – a process that develops, implements, monitors and measures productivity initiatives that will reduce costs while maintaining or improving service quality and work outputs (the Productivity Framework). The Productivity Framework has resulted in significant cost savings and benefits to ratepayers since its inception, and will continue to do so. The Productivity Framework and associated savings are further described in SPF Section 1.4.

In response to an OEB direction, Hydro One engaged an external consultant, Concentric Energy Advisors (Concentric), to independently review and assess the Productivity Framework. Concentric found that the Productivity Framework is an effective program (meeting all of the objective criteria for an effective program), and stands out as a strong and robust program compared to that of utility peers across North America. Concentric's conclusions included that "Hydro One's Productivity Framework stands out as being particularly robust, well defined, and transparent and distinguishes itself in its continuity and scope", and that it "is focused on delivering hard cost savings that can be measured, validated, and included in the Company's business planning." Concentric's report, detailing its findings and conclusions, is provided as Attachment 2 to SPF Section 1.4.

Consistent with best practices confirmed by Concentric, and also in response to feedback from prior proceedings, Hydro One has updated and enhanced its Productivity Framework in connection with this application and going forward. This includes updating and resetting the baseline of its productivity initiatives beginning in 2023, which (among other benefits) will: demonstrate a clear link to continuous improvement during the 2023-2027 period relative to prior proceedings; and embed historical achievement of existing initiatives in the new baseline, so as to measure and report on incremental savings over and above the prior and continuing savings from those initiatives.

A further enhancement relates to progressive productivity. Hydro One has updated and enhanced its approach to directly benefit customers. Hydro One will achieve its progressive productivity targets in connection with the Custom IR Framework through the productivity factors and the supplemental stretch factors it is proposing on capital. This provides direct and upfront savings and revenue requirement reductions to customers. Further, the productivity and supplemental stretch factors on capital will be applied in a cumulative manner in each year of the Application. This represents a change from Hydro One's previous Custom IR frameworks and results in a significant upfront revenue requirement reduction for customers.

This updated approach to achieve new and incremental productivity savings will meaningfully incent capital and OM&A savings that align with the annual, formulaic reductions to the revenue requirement. Productivity savings will be measured and tracked at the initiative level using Hydro One's Productivity Framework for both Transmission and Distribution businesses. As part of the Productivity Framework, Hydro One will continue to report on its productivity savings to senior leadership on a monthly basis.

Past and continuing productivity savings are embedded in the 2023-2027 plan. Hydro One's current productivity plan is expected to achieve approximately $351M of savings in 2022 between Transmission and Distribution based on the current measurement approach. This is the equivalent of reducing revenue requirement by $52M and $115M in 2023, for each of Transmission and Distribution, respectively. In other words, had Hydro One not implemented these productivity initiatives, while holding output constant, 2023 revenue requirement would be greater by these amounts. Ratepayers will continue to receive the benefit of these initiatives as planning at this level of efficiency has become part of normal business practice.

In addition and incrementally, ratepayers will also receive the benefit of the value of the stretch factors and supplemental stretch on capital in revenue requirement, derived using the methodology detailed in Exhibit A-04-02 and Exhibit A-04-03. For Transmission and Distribution respectively, this translates to a total of approximately $24M and $60M of revenue requirement reductions across 2023-2027. Incremental benefits will be achieved by identifying new initiatives as well as incremental achievement of current initiatives versus their updated baselines.

In summary, Hydro One will use the Productivity Framework to execute and achieve the stretch factor reductions to revenue requirement while meeting planned deliverables and outcomes. Any incremental savings in Capital and OM&A beyond those embedded in Hydro One's Application as part of the Custom IR framework both for Transmission and Distribution will result in a lower rebasing in Hydro One's next application for 2028, and incremental OM&A

savings may accrue to the ratepayer through the Earning Sharing Mechanism (ESM) during the rate period.

6.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A) EXPENSES

Hydro One is seeking approval of a total 2023 test year OM&A of $420.5M for the Transmission business, and $597.5M for the Distribution business. Hydro One's OM&A expenditures are comprised of the work required to meet public and employee safety objectives, maintain system reliability at targeted performance levels, and comply with legislative and regulatory requirements. The OM&A budgets have been set in order to deliver outcomes valued by customers, while balancing the needs of the systems and customer rate impacts.

A detailed summary of forecast OM&A expenses for the 2023 test year, along with envelope level variance explanations relative to the last approved rebasing year, the most recent year of actuals, and the forecast years leading up to 2023, are provided at Exhibits E-02-01 and E-03-01 for Transmission and Distribution, respectively.

6.1 TRANSMISSION OM&A EXPENDITURES

Hydro One Transmission's OM&A expenditures are comprised of the work required to meet public and employee safety objectives, maintain transmission system reliability at targeted performance levels, and comply with legislative and regulatory requirements, including those specified by the Transmission System Code, the North American Reliability Corporation (NERC), the Independent Electricity Systems Operator (IESO) and the federal environmental legislation associated with the PCB program.

Hydro One's 2023 test year OM&A budget of $420.5M represents a little more than an inflationary increase over the 2020 to 2023 period. Specifically, the 2023 test year OM&A is $11.9M (or 2.9%) higher than the 2023 amount that would result from escalating the 2020 OEB approved OM&A by inflation, which is $408.6M, as shown in Table 2 below.

Table 2 - 2023 Transmission OM&A Comparison

	($M)	**2023**
A	2023 Transmission Test Year OM&A	420.5
B	2020 OEB-Approved Transmission OM&A Escalated by Inflation in 2023 Terms[14]	408.6
C=A-B	Variance	11.9
D=C/B	% Change	2.9%

**Exhibit reference: E-02-01, Tables 1*

The modest increase to the 2023 OM&A budget also reflects the steps Hydro One has taken to implement two challenging historical reductions. First, in 2019 Hydro One filed an inflationary adjustment application rather than rebasing. In that application, Hydro One reduced its transmission OM&A by finding some permanent savings and by making some temporary, one-time reductions to OM&A. Second, the OEB cut Hydro One's requested OM&A in the Prior Transmission Application (EB-2019-0082) by $10.1M, which in turn similarly reduced 2021 and 2022 OM&A by virtue of the Custom IR formula.

Total Actual/Forecast OM&A for 2020-2022 is less than one percent higher than total OM&A amount included in the OEB-approved revenue requirement for the same period,[15] reflecting Hydro One's ability to control its costs and achieve productivity notwithstanding unplanned expenditures associated with COVID-19.

Starting in 2023 Hydro One needs to increase its OM&A spending mainly to: (i) address deferred stations maintenance that allowed Hydro One to continue funding PCB remediation work as planned in 2019-2022; (ii) address security needs related to evolving security threats and NERC CIP standards; and (iii) fund planned corrective maintenance work on overhead lines.

---

[14] Inflation rate of 2.0% was used annually, which is equal to the OEB-approved inflation rate from Hydro One's Transmission annual rate update application in EB-2020-0202.

[15] Calculated based on the Custom IR formula. For 2021 this is per the OEB-approved formula in *EB-2020-0202.* The 2022 amount was derived by applying the inflation rate less stretch factor equal to the OEB approved rate in *EB-2020-0202.*

The budgeted OM&A costs have been reduced by expected productivity savings, and reflect sustained cost control. Forecasted OM&A productivity savings through to the end of 2022 are reflected in the OM&A budget in 2023, by having these OM&A efficiencies become part of regular business planning and thus reducing upward pressure on future OM&A expenditures. These forecasted and continuing savings help to reduce the OM&A amounts being requested in this Application.

Table 3 provides a summary of OM&A expenditures for the historical, bridge, and test years. The 2020 OEB-approved funding is presented at the total envelope level, consistent with the envelope funding approved by the OEB in the Prior Transmission Application (EB-2019-0082). OM&A for 2024 to 2027 will be determined by the custom IR formula.

Table 3 - Summary of Recoverable OM&A Expenses ($M)

	Historical					Bridge	Test
	2018	2019	2020		2021	2022	2023
Transmission	**Actual**	**Actual**	**Actual**	**OEB-Approved**	**Forecast**	**Forecast**	**Forecast**
Sustainment	229.4	207.8	200.9	-	205.2	208.3	219.6
Development	5.2	4.4	6.7	-	8.3	8.9	8.6
Operations	53.4	51.0	47.9	-	48.8	48.6	49.0
Customer Care	11.0	7.2	7.0	-	6.0	6.7	6.9
Common and Other	54.9	26.7	70.5	-	51.6	50.7	65.0
Property Taxes and Rights Payments	65.3	60.8	65.4	-	69.1	70.2	71.4
Total	**419.2**	**357.9**	**398.5**	**385.0**	**389.0**	**393.4**	**420.5**

**Exhibit reference: E-02-01, Table 2*

In respect of compensation costs for both Transmission and Distribution, in order to prudently manage its overall costs, Hydro One has carefully planned its workforce resourcing requirements (in respect of both size and composition of workforce) to execute its work plan in an efficient and cost-effective manner – resulting in only a small increase in FTEs notwithstanding the significant increase in planned work over the rate period. Further, and in response to the OEB's direction in the Prior Transmission Application, Hydro One engaged Mercer to conduct an updated benchmarking study. The Mercer study results show that Hydro One has made significant progress in addressing its compensation levels relative to market – they have improved from being 12% above the P50 market median and 7% above the market range as of 2017, down to 9% above the P50 median and 4% above market as of 2020 (within +/- 5% of the P50 median is considered to be 'at market'). Additionally, this Application includes Hydro One's plan to further improve its levels of pay relative to market by 2027, working within the constraints of the collective bargaining regime. Details regarding the steps taken by Hydro One to manage its overall costs, the updated Mercer benchmarking study, and the plan to continue to further improve levels of pay relative to market, are discussed in Exhibit E-06-01.

Hydro One's Transmission-allocated compensation costs in 2022 and 2023 are summarized in Table 4 below. Further details are provided in Exhibit E-06-01. Hydro One's Distribution-allocated compensation costs in 2022 and 2023 are summarized in Section 6.2 below.

Table 4 - Summary of Total Transmission-Allocated Compensation Costs ($)

	2022 Bridge	**2023 Test**	**Change**
Capital - Transmission Compensation	478,188,667	498,172,879	19,984,212
OM&A - Transmission Compensation	188,955,014	195,673,989	6,718,975
Total Transmission Compensation	**667,143,681**	**693,846,868**	**26,703,187**

**Exhibit reference: E-06-01-02A*

6.2 DISTRIBUTION OM&A EXPENDITURES

Hydro One Distribution's OM&A expenditures are comprised of work required to meet public and employee safety objectives, maintain distribution system reliability at targeted performance levels, and to comply with regulatory requirements, including those specified within the Distribution System Code, and the federal environmental legislation associated with the PCB program.

Hydro One is seeking approval of a 2023 test year OM&A budget of $597.5M (including OM&A related to the Acquired Utilities). This 2023 budget represents a less than inflationary increase over the period from 2018 to 2023. Specifically, the 2023 test year OM&A is $4.1M (or 0.7%) lower than the amount that would result from escalating the 2018 OEB approved OM&A[16] by inflation, which is $601.6M. Further, when the 2023 test year OM&A amount is normalized[17] on the same basis as the amounts approved in the prior application, the equivalent 2023 OM&A is in fact approximately $36.4M (or 6.1%) lower than the 2018 approved OM&A escalated by inflation, as outlined in Table 5 below.

Table 5 - 2023 OM&A Comparison

	($M)	**2023**
A	2023 Distribution Test Year OM&A	597.5
B	Less: 2023 non-service costs component of OPEBs[18]	(20.1)
C	Less: 2023 Acquired Utilities' OM&A	(12.2)
D=A-B-C	2023 Equivalent Distribution Test Year OM&A	565.2
E	2018 OEB-Approved Distribution OM&A Escalated by Inflation in 2023 Terms	601.6
F=D-E	Variance	(36.4)
G=F/E	% Change	(6.1%)

**Exhibit reference: E-03-01, Tables 1*

Through its successful implementation of cost control initiatives and achievement of productivity, Hydro One is able to keep Distribution OM&A costs below the rate of inflation. That is the case even though the 2023 test year OM&A reflects the impacts of implementing the OEB's decisions in the 2018-2022 Distribution application and the 2020-2022 Transmission application (specifically in respect of the non-service cost component of OPEBs). Relative to amounts forecasted in the 2018-2022 Distribution application, there is higher achieved productivity due to various initiatives. This productivity benefit continues into 2023 by having

[16] 2018 is the test year of the prior Custom IR period, which was the year approved by the OEB, with 2019 to 2022 then resulting from the Custom IR Framework.
[17] For non-service costs component of OPEBs and Acquired Utilities' OM&A.
[18] To equate the 2023 OM&A to 2018 levels for comparison purposes, a normalization for non-service cost component of OPEBs of $20.1M was applied to 2023, as it was not previously included in the 2018 approved OM&A and consistent with the Transmission decision in EB-2019-0082.

these OM&A efficiencies become part of regular business planning and thus reducing upward pressure on future OM&A expenditures.

The total Actual/Forecast OM&A for the period of 2018-2022 is in fact lower by $54M than the total OM&A amount included in the OEB-approved revenue requirement for the same period,[19] further reflecting Hydro One's cost controls and incremental productivity achievements that more than offset unplanned expenditures such as incremental costs associated with COVID-19.

Table 6 provides a summary of OM&A expenditures for the historical, bridge, and test years. The 2018 OEB-approved funding is presented at the total envelope level, consistent with the envelope funding approved by the OEB in Hydro One's Prior Distribution Application (EB-2017-0049). OM&A for 2024 to 2027 will be determined by the Custom IR formula.

Table 6 - Summary of Recoverable OM&A Expenses ($M)

Distribution	Historical					Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
	OEB-Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	-	312.3	347.1	324.9	299.6	303.6	311.4
Development	-	7.5	7.1	6.0	10.0	10.2	11.0
Operations	-	37.3	36.6	33.0	39.7	41.3	40.8
Customer Care	-	111.7	97.8	111.2	108.6	107.9	118.3
Common and Other	-	84.9	66.3	79.7	68.0	67.0	110.0
Property Taxes & Rights Payments	-	5.1	4.6	5.4	5.6	5.8	6.0
Total	**544.4**	**558.8**	**559.6**	**560.2**	**531.4**	**535.8**	**597.5**

**Exhibit reference: E-03-01, Tables 2*

[19] Calculated based on the Custom IR formula. For 2019-2021, this is per the OEB approved formula in *EB-2017-0049, EB-2019-0043, and EB-2020-0030.* The 2022 amount was derived by applying the inflation rate less stretch factor equal to the OEB approved rate in *EB-2020-0030.*

In respect of compensation costs, Hydro One's total Distribution-allocated compensation costs are summarized in Table 7 below. Further details are provided in Exhibit E-06-01.

Table 7 - Summary of Total Distribution-Allocated Compensation Costs ($)

	2022 Bridge	2023 Test	Change
Capital - Distribution Compensation	395,241,353	406,071,193	10,829,840
OM&A - Distribution Compensation	379,295,578	391,638,108	12,342,530
Total Distribution Compensation	**774,536,931**	**797,709,300**	**23,172,369**

**Exhibit reference: E-06-01-02A*

7.0 SYSTEM PLANS

This section summarizes the major drivers and elements of Hydro One's five-year System Plans. It summarizes Hydro One's capital planning process and the proposed capital spending over the 2023-2027 planning period.

The planning framework that underpinned each of the TSP, DSP and GSP is informed by the Company's planning strategy and consists of two interrelated processes. First is a thorough and ongoing asset management process that involves the monitoring and review of power system and common infrastructure assets (including condition assessments), 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 that help drive Hydro One towards achieving its intended outcomes (Investment Planning).

7.1 STRATEGY & CONTEXT

Hydro One's planning process began with consideration of its Strategic Priorities, the OEB's RRF outcomes, and customer engagement findings. Hydro One's Strategic Priorities reflect the Company's commitment to exceptional customer service, safety, innovation, efficiency and sustainability, and are summarized in Figure 1 below. There is close alignment between the RRF outcomes and the priorities/outcomes that Hydro One seeks to achieve (see SPF Section 1.7.2).

Figure 1: Hydro One's Strategic Priorities

Hydro One also relied upon the findings from its comprehensive customer engagement activities to inform the initial stages of planning. Specifically, Phase 1 of the IRG study took place in late 2019 and early 2020, prior to the beginning of investment planning for 2023–2027. This phase focused on identifying customer needs and preferences that helped guide planner assumptions regarding the appropriate investment levels and trade-offs, including, among other things, the importance of reliable service and reasonable rates to Distribution and Transmission customers and the customer segment support for the proactive replacements of power system infrastructure when or before they deteriorate.

7.2 ASSET MANAGEMENT

As detailed in SPF Section 1.7, TSP Section 2.7, DSP Section 3.7 and GSP Section 4.7, Hydro One employs a methodical asset management process to monitor its assets and determine the appropriate timing for asset maintenance and capital investments throughout the asset life cycle. The output of the asset management process is a key component of the investment planning process.

The development of candidate investments is underpinned by a needs assessment which considers different dimensions including (i) asset-specific investment needs (particularly condition), (ii) customer needs and preferences, and (iii) system needs (including regional planning considerations). Each of these are described below.

7.2.1 ASSET NEEDS ASSESSMENT

Hydro One performs a needs assessment to identify the drivers in the development of candidate investments and collect the data necessary to assess risks and facilitate the subsequent calibration process. The needs assessment process is centred on a continuous asset risk assessment (ARA) to determine individual asset needs. The ARA is primarily concerned with the major equipment groups across transmission (e.g., transformers, conductors, breakers, and protection and control systems) and distribution (e.g., station transformers, poles) that directly affect system reliability. In particular, asset condition, criticality, performance and utilization are key factors to identify asset risks for further screening and confirmation:

- Condition – risk related to the increased probability of failure that assets experience when their condition degrades over time.
- Criticality – represents the impact that the failure of a specific asset would have on the transmission or distribution system.
- Performance – risk that reflects the historical performance of an asset, typically 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.

Hydro One also considers 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 help ensure that capital expenditures target the appropriate mix of assets.

On-site assessments with field personnel are conducted to validate and confirm asset condition, based on site specific considerations. For high-value assets, such as transformers, subject matter experts perform a thorough assessment of asset condition and consider issues such as equipment obsolescence, manufacturer support, and "repair versus replace" evaluations. Inspection and validation ensure that the identified needs reflect the actual condition of assets in the field and relevant operating information including the concerns of field personnel.

Many system renewal investments are informed by the asset needs assessment process, largely driven by asset condition. Material planned investments include:

- D-SR-04 – Distribution Station Refurbishments to address poor condition station transformers
- D-SR-05 – Distribution Pole Replacements to address poor condition wood poles
- D-SR-12 – Advance Meter Infrastructure 2.0 to address poor performing and obsolete first generation meters
- T-SR-02 – Transmission Air Blast Circuit Breaker Replacements to address poor condition and poor performing air blast circuit breakers
- T-SR-19 – Transmission Line Refurbishments to address poor condition overhead conductors and related infrastructure

7.2.2 CUSTOMER NEEDS & PREFERENCES

As noted in Section 4.0 above, Hydro One conducted extensive customer engagement in 2019 and 2020. Investment planning and customer engagement processes were integrated over two phases and customer feedback was provided as key input into Investment Planning. With consideration of the findings from Phase 1 customer engagement, Hydro One developed three investment plan scenarios for each of the Transmission and Distribution businesses between

February and June 2020. Each plan scenario included a different level of investment and service outcome, with a corresponding rate impact. Hydro One presented these scenarios to customers in Phase 2 of customer engagement, and resulting customer feedback on those scenarios was considered and incorporated for the purpose of refining and finalizing the investment plan. This approach allowed Hydro One to develop a final investment plan for 2023-2027 that is responsive to customer needs and preferences. See SPF Section 1.6, TSP Section 2.6, DSP Section 3.6, and GSP Section 4.6 for further details regarding customer engagement. See SPF Section 1.7, TSP Section 2.7, DSP Section 3.7, and GSP Section 4.7 for further details on how customer results were integrated into the planning process.

7.2.3 SYSTEM NEEDS

System needs relate to work required to maintain and operate the transmission and distribution systems and adequately and reliably supply customers, driven in large part by the requirement to meet current and forecast needs based on the connection of new load customers, generation facilities and distributed energy resources (DERs). System needs include:

- Provision of adequate capacity to reliably deliver electricity to the local areas connected to Hydro One’s system;
- Addressing local area reliability performance, including pockets of distribution customers which may experience poor reliability;
- Implementing mitigation measures to minimize high-impact events and ensure the safe, secure and reliable operation of Hydro One’s transmission system in accordance with the IESO’s Market Rules, OEB’s Transmission System Code, and other mandatory industry standards such as those established by NERC and Northeast Power Coordinating Council (NPCC);
- Meeting regional transmission facility needs identified as part of the regional planning process; and
- Local distribution upgrades and enhancements to relieve system capacity constraints and meet forecast load growth, consistent with the requirements of the Distribution System Code.

System needs assessments, regional planning, and bulk planning processes result in the identification of System Service investments, including:

- D-SS-01 – System Upgrades drive by load growth to address local and regional capacity constraints
- D-SS-02 – Reliability Improvements to improve regional reliability performance
- T-SS-03 – Merivale x Hawthorne Upgrades to increase capacity to meet future demand requirements

7.3 INVESTMENT PLANNING

Based on identified investment needs, Hydro One develops a suite of candidate investments for further screening and prioritization. In this regard, opportunities to group and bundle related needs, based on logical, functional and geographic groups, are considered where appropriate. The information and data collected through the asset management process (particularly, the ARA) establish the requisite fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the investment planning process.

Through its investment planning process, Hydro One develops a consistent understanding of risks and investment benefits to cost effectively deliver high value investments to serve its customers. This process allows the effective assessment and prioritization of candidate investments (as identified through the asset management process) based on the level of risk mitigated relative to the cost required.

In this regard, Hydro One planners determine risk probability (based on asset condition, performance and utilization) and risk consequence (based on asset criticality across three taxonomies of safety, reliability and environmental risks). Each risk taxonomy features clear definitions and consistent assessment, permitting a proper comparison between candidate investments. Planners quantify the risk mitigated by comparing the expected operational risks of not making the investment versus the residual risks that would remain if the investment is made. As an important basis for prioritization, this risk assessment emphasizes fact-based and quantitative decision-making, relying on historical data to the extent possible and taking into account the efficiency and total benefits of risk mitigated by each candidate investment.

Notably, customer-driven outcomes directly impact this process through the definition of consequence scores and risk taxonomies as well as “flags” that reflect priorities and investment benefits beyond quantified risk mitigation. In alignment with RRF outcomes and corporate priorities, flags are clearly defined to reflect either mandatory obligations (e.g., obligations to regulators, stakeholders or contractual counterparties) or customer preferences and other priorities (e.g., productivity commitments, corrective maintenance/replacements, preventative maintenance/renewal).

Once candidate investments have been scored and flagged, enterprise-wide calibration sessions are held to ensure consistent evaluation across investments and lines of business. Based on the risk scores and estimated investment costs, candidate investments (broken into mandatory versus non-mandatory groups) are ranked according to risk mitigation achieved per dollar. As another layer of planning rigor and validation, challenge sessions take place among a broad set of stakeholders to debate the feasibility and merits of investments on the margin and to ensure that valuable investments (from both a risk and non-risk perspective) are included in the plan. As well, Phase 2 customer engagement results were incorporated into the final plan at this stage. The output is an investment portfolio that is subject to enterprise engagement with portfolio owners and the executing lines of business, so as to create a realistic and up-to-date plan (i.e. reflecting the latest cost estimates, schedules and investment scope) and account for operational and execution considerations (e.g., resourcing, material availability and outage feasibility).

The Investment Planning process is described in greater detail in SPF Section 1.7 (as well as TSP Section 2.7, DSP Section 3.7, and GSP Section 4.7).

7.4 TRANSMISSION CAPITAL EXPENDITURES

Table 8, below, summarizes Hydro One's planned transmission capital expenditures by OEB category over the 2023-2027 planning period with productivity savings.

Table 8 - Transmission Capital Expenditure Summary

	Forecast Period ($M)				
OEB Category	**2023**	**2024**	**2025**	**2026**	**2027**
System Access	79.4	70.9	59.8	36.5	50.1
System Renewal	1178.0	1228.3	1251.6	1277.3	1264.0
System Service	90.9	101.6	85.8	93.1	90.1
General Plant	146.8	124.0	114.2	115.9	105.0
Subtotal	**1495.0**	**1524.9**	**1511.4**	**1522.8**	**1509.2**
Productivity[20]	-61.0	-61.0	-61.0	-61.0	-61.0
Grand Total	**1434.0**	**1463.9**	**1450.4**	**1461.8**	**1448.2**

**Exhibit Reference: TSP Section 2.1 Table 4*

Over the 2023-2027 period, Hydro One plans to invest an average of $1,451.7M per year in Transmission capital, for a total of $7,258.4M, to respond to a range of asset and system needs, and to meet the customer service imperatives that are at the core of Hydro One's business mandate. System Renewal investments account for 82% of Hydro One Transmission's 2023-2027 capital plan. These investments will manage and mitigate risks stemming from assets that are in poor condition, have inadequate performance or are obsolete. The proposed System Service and System Access investments are non-discretionary and account for 10% of the total capital plan. The remaining 8% of the proposed capital plan are attributable to the General Plant investments.

[20] Progressive productivity represents commitments made for 2022 that will be sustained through the test period. See SPF Section 1.4 for a further explanation on the rationale for only including 2022 progressive productivity during the test period.

System Access

Hydro One's transmission capital plan includes $296.7M (4%) of capital expenditures over the five-year period required for non-discretionary System Access investments that facilitate new load and generation customer connections and address transmission asset modifications to accommodate third party requests. Major investments include $189.1M in capital expenditures to connect load customers by building new or expanding existing transformer stations to increase capacity, meet load growth and provide connections to customers. This includes the connection to six traction power stations for the Metrolinx rail electrification project. The expansion of the agricultural sector and unprecedented load growth in the Windsor-Essex region of Southwest Ontario is the most significant driver of expenditure in this subcategory, representing $129.1M (51%) of the capital expenditures. The load forecast in the region is anticipated to double over the next five years, requiring three new load supply stations to connect and supply new customers in the region.

System Renewal

Over 10% of all major transmission assets are in poor condition, with two of these asset categories (transformers and conductors) experiencing increasing numbers of deteriorated assets compared to prior years and the remaining asset categories remaining relatively stable compared to prior years.[21] Deteriorated assets are more likely to fail, resulting in unplanned outages that are more costly to address and may have widespread impact on service. The need to address such assets is one of the major factors driving the proposed System Renewal investments. System Renewal investments have been selected based on asset condition, their criticality, performance and obsolescence criteria, considering customer needs and preferences, and Hydro One's ability to execute the renewal work. System Renewal investments have been reasonably paced to address assets that are in poor condition, have inadequate performance or are obsolete, including an average annual pacing of: 3.3% of the transformer fleet, 2.5% of the

[21] Transformers (116 units in poor condition in 2016, and 198 in 2020), breakers (499 in 2016 and 541 in 2020), protection systems (3,267 in 2016 and 3,397 in 2020), conductors (2,643 in 2016 and 3,874 in 2020), and wood poles (4,832 in 2016 and 4,693 in 2020).

breaker fleet, 3.4% of the protections fleet, 1.1% of the conductor fleet, 3.3% of the insulator fleet, 2.7% of the wood pole fleet, and 1% of the steel structure fleet (via tower coating to extend their useful life).

The plan includes station renewal investments, which are required to address station assets including transformers and circuit breakers, as well as protection, control and telecom equipment. Major station renewal investments include $1,569.7M over the five-year period through 35 investments that will replace network station assets that are in poor condition, have inadequate performance or are obsolete, which link major generation resources to load centers. Hydro One's network system forms part of the Bulk Electric System (BES), and as such the proposed renewal investments are required to ensure continuous power flow throughout the province and to meet relevant IESO, NERC and NPCC criteria. Expenditures in this category address refurbishment work at major stations and replace Air Blast Circuit Breakers (ABCBs) through 11 investments. ABCBs are the poorest performing breakers in Hydro One's transmission system. These assets are installed at Ontario's most critical transmission network stations that connect nuclear and hydraulic generation stations that account for a total output equal to 30%[22] of Ontario's electricity generation. Station renewal investments also include $1,877.3M over the five-year period through 102 investments that will replace connection station assets that are in poor condition, have inadequate performance or are obsolete, that connect network stations and transmission load delivery points. LDCs and large industrial facilities are among the customers served by connection stations. The LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users.

The plan also includes lines renewal investments, which are required to address deteriorated lines components including conductors, wood poles, towers, insulators and shieldwire. Major investments include $833.2M over the 5-year period through 16 investments to address poor

---

[22] (11,607MW/38,944MW) x 100%; see https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2021Mar.ashx.

condition lines assets. This renewal work sustains a variety of network and radial line connected customers, including large and small municipalities, First Nations communities and businesses, large load facilities such as petrochemical processing facilities, mines and paper mills. Lines renewal investments also include $1,085.8M over the five-year period to address various transmission line components (e.g. wood poles, insulators, shieldwires) that have been confirmed to be in poor condition. These components are integral parts of transmission line system required to enable and support the overhead conductor to perform its functions.

<u>System Service</u>

Hydro One's transmission capital plan includes $461.4M (6%) of capital expenditures over the five-year period required for non-discretionary System Service investments that maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. These investments have been identified as a result of regional planning processes, IESO bulk planning studies or the 2017 Long-Term Energy Plan (2017 LTEP). As the lead transmitter, Hydro One is actively involved in the regional planning process and the development of regional infrastructure plans for 19 of the 21 regional planning zones in Ontario.

Major System Service investments include $191.7M capital over the five-year period for inter-area capacity investments, which will provide new or upgraded transmission facilities to increase the transfer capability within Ontario and with neighbouring utilities. A significant driver of investment is the required reinforcements identified by the IESO as a part of bulk planning studies for the West of Chatham and West of London transmission systems. The IESO has directed Hydro One to develop new 230 kV lines between Chatham and Lakeshore (West of Chatham) and Lambton and Chatham (West of London) because of unprecedented growth in the agricultural sector in the Windsor-Essex region of Southwest Ontario and the need to ensure the necessary bulk transfer capability to support growth in load and generation. The required station expansion work to facilitate these new transmission lines represents 38% of the System Service expenditures. Hydro One plans to invest $230.5M net capital over the five-year period in local area supply to provide new or upgraded facilities to ensure area supply adequacy, and meet load forecast requirements in areas where existing transmission facility loading levels reach or exceed capacity.

The transmission capital plan also includes $606.0M of General Plant capital that is required over the planning period, as detailed in Section 7.6 below.

Further details regarding the transmission capital plan may be found in the TSP.

7.5 DISTRIBUTION CAPITAL EXPENDITURES

Table 9 below summarizes Hydro One's planned distribution capital expenditures by OEB category over the 2023-2027 planning period.

Table 9 - Distribution Capital Expenditure Summary

OEB Category	Forecasting Period ($M)				
	2023	2024	2025	2026	2027
System Access	239.6	240.6	227.0	212.6	204.3
System Renewal	373.1	410.3	494.2	491.5	497.8
System Service	196.5	169.7	229.6	192.0	205.9
General Plant	195.9	207.4	170.1	175.5	162.9
Total	**1,005.1**	**1,028.0**	**1,120.8**	**1,071.7**	**1,070.9**

**Exhibit reference: DSP Section 3.1, Table 3*

Over the planning period, Hydro One plans to invest an average of $1,059.3M per year in Distribution capital, for a total of approximately $5.3B. These investments will enable Hydro One Distribution to connect new customers and meet the growing needs of communities across the province, including the agricultural sector in southwestern Ontario, as well as to address a range of other priorities. In particular, investments in the distribution system will enable Hydro One to modernize existing facilities through automation to improve overall reliability, deliver on obligations mandated by legislation and regulatory requirements, address customer needs and preferences, and mitigate asset and operational risks by addressing critical asset needs to sustain the current fleet of assets. Moreover, the investments will support improved emergency response and the replacement and refurbishment of distribution poles. The plan will also focus on replacing first generation advanced metering infrastructure, which are failing, through a paced approach, setting the foundation for cost-effective grid modernization initiatives, DER integration, in-home automation and other technologies.

System Renewal

Planned System Renewal investments total $2,266.9M or about 43% of the total DSP, and are critical to addressing the growing population of distribution assets that are in poor condition. Major System Renewal investments will address a subset of poor condition distribution wood poles, replace end of service life meters and metering infrastructure, maintain or restore the continuity of supply for customers, and reconstruct and relocate feeder sections that are in poor condition and difficult for crews to access in the event of an outage. Failure to address these and other System Renewal investment needs over the 2023-2027 period will pose an ever-increasing reliability risk. DSP Section 3.11 includes detailed descriptions of each investment.

Accounting for 25% of the System Renewal category, the pole sustainment program includes planned expenditures of $562.6M over the 2023-2027 period. Out of the 1.6M distribution poles owned and maintained by Hydro One, approximately 79,000 poles are in poor condition and at high risk of failure, as identified through condition assessments. The pole sustainment program will proactively test and treat 103,000 poles, refurbish 2,800 poles, and replace 10,300 poles annually.[23] Together, the replacement and refurbishment work will address 13,100 poles annually or 65,500 poles over the five-year period. This plan only addresses a subset of the poor condition poles and allows Hydro One to effectively manage the poles that pose the highest risk to customer reliability. The volumes of poles addressed are consistent with the customer engagement results. Under this approach, poles with the lowest potential impact on customer reliability will be replaced reactively if they were to fail. Details on Hydro One's pole

[23] The test and treat and pole refurbishment programs are new programs introduced in 2021.

sustainment strategy, including details on the rationale, timing, and scope of the program, can be found in DSP Section 3.2 as well as in DSP Section 3.11, D-SR-07.

Hydro One's existing meter infrastructure is approaching its end of service life and needs replacement. The Advanced Metering Infrastructure (AMI) 2.0 program (DSP Section 3.11, D-SR-12), represents planned replacement of Hydro One's legacy AMI 1.0 system. Hydro One forecasts expenditures of $558.3M (or about 25% of the System Renewal category) for this investment in the 2023-2027 period. The AMI 1.0 system is comprised of approximately 1.4M meters, of which approximately 840,000 are between 11-13 years old and will soon reach the end of their expected 15-year service life. Manufacturer service life attestations, benchmarking studies, independently conducted Accelerated Life Testing (ALT) of meters, and trends in increasing meter failures all support an approximately 15-year service life for AMI 1.0 meters. Notably, the ALT study found critical failures in meters involving the rapid degradation of the capacitor that enables meters to reliably communicate. Based on these findings, close to 579,000 meters are projected to fail by the end of the test period in 2027. The physical deterioration of meter components and meter failures pose impacts and critical risks to Hydro One affecting various elements of its business including:

- Reduced billing reliability and resultant customer dissatisfaction from estimated billing and billing corrections;
- Increasing costs associated with reactive individual meter replacements as a result of failed meters;
- Higher labour costs for unplanned individual failed meter replacement relative to mass meter replacement;
- Replacement of failed meters with obsolete technology, and the associated lost opportunities for future benefits that address foreseeable needs; and
- Regulatory non-compliance.

Additional details on the rationale, timing, and scope of the AMI 2.0 program investment can be found in DSP Section 3.2 and in DSP Section 3.11, D-SR-12.

The Distribution Lines Trouble Calls and Storm Damage Response program represents total expenditures of $551.7M (or about 24% of the System Renewal category) over the 2023-2027 period. These expenditures comprise the work required to maintain or restore the continuity of supply for Hydro One customers. Hydro One's forecasting for storm response expenditures is based on an inflation-adjusted average of annual expenditures since 2005, with "outlier" years of unusually high expenditures removed from the forecast.

The Distribution Lines Sustainment Initiatives program represents total expenditures of $183.0M (or about 8% of the System Renewal category) over the 2023-2027 forecast period. This program involves the reconstruction of feeder sections (involving about 5,200 poles) that are in poor condition, including the relocation of off-road sections (about 460km in length) that are difficult for crews to access in the event of an outage. These expenditures are expected to reduce the frequency of both sustained and planned outages for the line sections that have been reconstructed, and reduce restoration efforts where an off-road feeder section has been reconstructed within road allowances. Additionally, about 200 km of direct buried underground cable will be treated to improve their life expectancy by up to 40 years.

System Access and System Service

The DSP includes $1,124.1M in proposed System Access and $993.7M in System Service capital investments over the 2023-2027 period.

System Access investments represent 21% of the total capital portfolio in the forecast period. They are driven by statutory, regulatory or other mandatory obligations that Hydro One must meet to provide access to the distribution system. Primarily, investments relate to customer requests for connection or connection modifications, but can also include the relocation of system assets to accommodate municipal infrastructure development or modifications, third party requests for joint use attachments, and replacement of failed meters to maintain customer billing reliability.

System Service investments are modifications to Hydro One's distribution system to ensure that the system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. Over the 2023-2027 period, System Service investments will increase to meet load growth, address worst performing feeders, and install energy storage to improve reliability for customers where conventional alternatives are not possible or cost prohibitive. The largest investment in this category is the suite of energy storage solution investments that will address the needs of customers with especially poor reliability.

The DSP also includes $911.8M of general plant capital that is required over the planning period, as detailed in Section 7.6 below.

Further details regarding distribution capital may be found in the DSP.

7.6 GENERAL PLANT CAPITAL EXPENDITURES

General Plant assets are critical to the utility's operational continuity and the successful execution of a complex portfolio of Transmission and Distribution work programs. Hydro One's main General Plant functions include Fleet, Facilities and Real Estate (F&RE), Information Solutions and System Operations. For the purposes of this Application, the GSP presents total expenditures for General Plant investments and the allocation of those expenditures to Transmission and Distribution.[24] The GSP capital expenditures for the 2023-2027 period are summarized in Table 10.

[24] General Plant investments include capital expenditures that are either (i) shared between Transmission and Distribution; or (ii) are fully attributable to Transmission or Distribution and fall under the General Plant OEB investment category. For shared investments, the allocation between Transmission and Distribution is based on Black and Veatch's Shared Asset Allocation Study presented in Exhibit E-04-08 Attachment 1.

Table 10 - Planned net capital expenditures for General Plant from 2023-2027

OEB Category	Forecast Period (Planned $M)				
	2023	**2024**	**2025**	**2026**	**2027**
Fleet	76.4	78.0	78.9	80.0	82.6
Facilities & Real Estate	91.4	92.1	61.7	58.1	50.5
Information Solutions	119.9	118.1	113.6	122.1	106.1
System Operations	27.4	18.5	8.2	8.0	6.5
Other	27.5	24.6	22.0	23.2	22.3
General Plant Total	**342.7**	**331.4**	**284.3**	**291.4**	**268.0**
General Plant - Transmission Allocation	146.8	124.0	114.2	115.9	105.0
General Plant - Distribution Allocation	195.9	207.4	170.1	175.5	162.9

**Exhibit reference: GSP Section 4.1, Table 2*

The annual GSP capital expenditures range from $268.0M to $342.7M during the forecast period, with higher levels in 2023 and 2024. Year–to-year variations in total capital expenditures are mainly driven by the timing of investments in F&RE and System Operations.

The investments planned under the GSP are summarized below by function:

- **Fleet** – Planned Fleet investment levels remain relatively steady during the forecast period, gradually increasing from $76.4M to $82.6M per year. This level of investment is required to minimize fleet lifecycle costs and equipment downtime (consistent with expert-recommended lifecycles and investment pacing). In turn, this allows Hydro One to optimize fleet equipment levels to meet work program demands and mitigate potential delays in response time to unplanned system interruptions, such as trouble calls and storm response.
- **Facilities and Real Estate** – Planned F&RE investments total just above $90M in each of 2023 and 2024 ($91.4M and $92.1M, respectively), and follow a decreasing trend from $61.7M in 2025 to $50.5M in 2027. The initial peak in the earlier test years is driven by projects to address end of life assets, consolidate facilities to manage lease expirations, and meet facility-related operational requirements of Hydro One's Transmission and Distribution businesses. Hydro One has identified existing sites that are sub-optimal for operations due to overcrowding conditions, inefficient configurations, and/or disparate

sites for field teams. The proposed investments aim to consolidate these facilities to increase efficiencies, accommodate growth, and reduce operational costs (e.g., by terminating leases). Similar investments are planned in 2025 through 2027 at a lesser volume. Throughout all test years, there are baseline investments of approximately $30M for on-going sustainment program work to address end of life conditions, safety and security concerns, exterior structures and elements, and building systems and accommodations.

- **Information Solutions** – These investments range from $106.1M to $122.1M annually, with a focus on providing Hydro One lines of business with the technology required to complete their work and enable them to achieve the expected outcomes of their respective System Plans. These investments include:
  - upgrades to existing applications that are approaching their end of vendor support, such as foundational investments in Hydro One's SAP enterprise software and Geographic Information System (GIS) enterprise platform, and refresh of IT hardware and software to ensure lines of businesses have reliable access to technology to complete daily work;
  - digital transformations of paper processes and automation of manual tasks to improve operational efficiencies and access and quality of data;
  - updates to systems used by transmission and distribution planning, execution and field teams to improve efficiencies in work delivery and increase visibility of asset conditions and work plans across these lines of businesses; and
  - improvements to Hydro One's security posture, such as upgrades to the cyber security assets protecting the operating technology infrastructure and applications that monitor and control Hydro One's power system, upgrades to the physical security protecting critical stations and facilities to reduce the risk of external threats, and refresh of Hydro One's security monitoring solution that is nearing its end of life and vendor support period.
- **System Operations** – These investments decrease over the forecast period, starting from $27.4M in 2023 and decreasing to $6.5M in 2027. This trend reflects the upgrade

of all critical systems applications that are at or are nearing the end of vendor support, including the Network Management System, Outage Response Management System and Distribution Management System.

- **Other General Plant** – These investments include the replacement of grid control equipment that are nearing their end of vendor support and capital contributions from Distribution to Transmission. These capital expenditures are relatively steady during the planning period, ranging from \$22.0M to \$27.5M annually. Investments in grid control are required to ensure compliance with IESO market rules and the capital contributions between Hydro One's Distribution and Transmission businesses are required as per the Transmission System Code.

8.0 PERFORMANCE MEASUREMENT & INDEPENDENT STUDIES

8.1 PERFORMANCE MEASUREMENT

Hydro One tracks and reports its performance relative to: (i) its Transmission Scorecard; (ii) its Distribution OEB Scorecard; and (iii) the OEB-mandated Electricity Distributor Scorecard. Each of these are included and described below.

The Transmission Scorecard is included in Figure 2 below. The measures in the scorecard were developed based on RRF outcomes, past measures, benchmarking studies and relevant measures on other scorecards. The targets were developed based on the expected outcomes of the projects and programs proposed in this Application. The performance reporting governance framework is described in SPF Section 1.5 and information on the proposed transmission measures and targets is found in TSP Section 2.5.

Performance Outcomes	Performance Categories	Measures
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs
	Customer Satisfaction	Overall Customer Satisfaction (% Satisfied)
		Satisfaction with Outage Planning Procedures (% Satisfied)
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)
		Transmission Capital Accomplishment Index (TCAI) - (%)
	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 2: Electricity Transmitter Scorecard Measures

Hydro One Distribution measures its performance under the OEB's RRF through the Electricity Distributor Scorecard, shown in Figure **3**, and the Distribution OEB Scorecard, shown in Figure **4**. The Electricity Distributor Scorecard is the OEB-mandated scorecard for all Ontario electricity distributors and is discussed in detail in DSP Section 3.5.

Performance Outcomes	Performance	Measures	
Customer Focus **Services are provided in a**	**Service Quality**	New Residential/Small Business Services Connected on	
		Scheduled Appointments Met On Time	
		Telephone Calls Answered On Time	
		First Contact Resolution	
		Billing Accuracy	
		Customer Satisfaction Index	
Operational Effectiveness **Continuous improvement in**	**Safety**	Level of Public awareness	
		Level of Compliance with Ontario Regulation 22/04	
		Serious Electrical	
			Rate per 10, 100, 1000km of line
	System Reliability	Average Number of Hours that Power to a Customer is	
		Average Number of Times that Power to a Customer is	
	Asset Management	Distribution System Plan Implementation Progress	
		Efficiency Assessment	
		Total Cost per Customer	
		Total Cost per km of Line	
Public Policy Responsiveness **Distributors deliver on**	**Conservation &**	Net Cumulative Energy Savings	
	Connection of	Renewable Generation Connection Impact Assessments	
		New Micro-embedded Generation Facilities Connected	
Financial Performance **Financial viability is maintained;**	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current	
		Leverage: Total Debt (includes short-term and long-term	
		Profitability:	
			Achieved

Figure 3: Electricity Distributor Scorecard

The Distribution OEB Scorecard, shown in

Figure **4** below, supplements the Electricity Distributor Scorecard with additional measures to track outcomes that customers value and areas that Hydro One has targeted for improved performance.

RRF Outcomes		Measure
Customer	Customer Satisfaction	Small Business and Residential Satisfaction (%)
		Handling of Unplanned Outages Satisfaction %
		Call Centre Customer Satisfaction %
		My Account Customer Satisfaction %
Operational	Cost Control	Pole Replacement - Gross Cost Per Unit in $
		Vegetation Management - Gross Defect Correction (OCP) Cost per km$
		Station Refurbishments - Gross Cost per MVA in $
		OM&A dollars per customer
	System	
		Number of Vegetation Caused Interruptions
		Number of Substation Caused Interruptions
		SAIDI for Equipment Caused Interruptions
		SAIDI for Vegetation Caused Interruptions
		SAIDI - Rural - duration in hours
		SAIFI - Rural - frequency of outages
		SAIDI - Urban - duration in hours
		SAIFI - Urban - frequency of outages
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA

Figure 4: Distribution OEB Scorecard

Hydro One is committed to both sets of Distribution performance measures in evaluating its progress in executing the 2023-2027 investment plan, which balances the needs and preferences of customers, compliance obligations, asset condition/needs, and rate impacts. Hydro One's plan reflects a number of initiatives that control costs, increase productivity and maintain customer reliability. These are all outcomes that customers have indicated they value, are central to Hydro One's corporate objectives, and align with the OEB's RRF.

8.2 INDEPENDENT EXPERT STUDIES

In support of the Application, Hydro One engaged independent experts to undertake various benchmarking assessments, process reviews, asset condition analyses, and lifecycle studies.[25] Highlighted below are the key conclusions from various studies, which helped Hydro One understand its performance relative to peers (or relative to its own past performance), formulate key components of the Custom IR proposal, inform or validate business processes and investment choices, and/or identify opportunities for improvement. Table 11 below is not intended to be a comprehensive summary of findings from all studies, which are detailed in the relevant reports and exhibits.

Table 11 - Key Findings of Independent Expert Studies

Reference	Report	Highlighted Conclusions
A-04-01, Attachment 1	Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application – Clearspring Energy Advisors	• Based on findings related to Transmission (including declining trends in industry total factor productivity as well as Hydro One's superior total cost performance), 0% was recommended for both the transmission base productivity factor and transmission stretch factor. • Based on findings related to Distribution (including negative industry total factor productivity trends as well as Hydro One's average total cost performance), 0% was recommended for the distribution base productivity factor and 0.3% for the distribution stretch factor.
SPF Section 1.4, Attachment 2	Hydro One Productivity Framework Review - Concentric Energy Advisors	• Hydro One's Productivity Framework is effective at identifying and quantifying productivity initiatives, appropriately applies baselines for measurement, has an appropriate validation/audit process, drives true productivity gains, and considers productivity in the context of forward looking planning. • Relative to peers, this framework stands out as being uniquely robustly, well defined, and transparent, and distinguishes itself in its continuity and scope.

[25] The approach for procuring the services of third party experts is discussed in SPF Section 1.3.

TSP Section 2.3, Attachment 1	Transmission Capital Project Execution Review - UMS	• Hydro One is second quartile or better in 7 of the 10 performance domains (including Cost Management, Scope Management, Resource Management, Risk Management, Quality Management and Contract Communications). • Hydro One is at the median in two domains: Schedule Management and Integration Management. • Hydro One is approaching the third quartile in Technology Enablement.
TSP Section 2.3, Attachment 2	Pole Replacement Program Study - Guidehouse and First Quartile	• Hydro One Transmission's wood pole replacement practices are in line with comparators and replacement costs ($27,450 per pole) are below the comparator group mean ($32,882). • In the last 5 years, on average Hydro One replaced 2.1% of its wood poles annually, vs. 2.6% for the comparator group. Hydro One expects to replace 2.9% of its poles per year in the next 5 years, vs. 2.2% for the comparator group. Given the age and condition of Hydro One's wood poles, "a marginally higher replacement rate is expected".
TSP Section 2.3, Attachment 3	Transformer Condition Assessment - EPRI	• Of the 208 transformer tanks that Hydro One deems to be in poor condition, EPRI's analysis of main tank oil data confirmed main tank degradation for 155, deemed 17 to be in marginal condition, and found 36 to not be in poor or marginal condition. (Note that the 208 units were deemed poor by Hydro One based on a combination of factors including but not limited to main tank oil tests, such as oil leaks, tap changer issues, cooling system issues, etc.).
TSP Section 2.3, Attachment 4	Line Loss Assessment - Stantec	• Hydro One follows industry best practices with respect to transmission line loss management. Its Transmission Line Loss Guideline provides a reasonable, clear and efficient process for considering the cost of losses in evaluating alternatives. • Stantec recommended (i) consistent implementation of the Guideline for new investments that impact line losses and (ii) tracking of projects assessed for line loss and associated loss reduction as documented in approved business cases.
DSP Section 3.3, Attachment 1	Distribution Poles and Substations Benchmarking - Guidehouse (formerly Navigant) and First Quartile	Poles: • Hydro One Distribution replaces poles based on condition and has a higher replacement rate, including poles replaced on failure, than comparators (recognizing that the industry as represented by the comparator group appears to be replacing or refurbishing poles at a rate that is insufficient to sustain their pole population over the long term). • Hydro One's pole replacement costs are comparable to the mean of the comparator group. Substations: • Hydro One has lower than average costs to replace power transformers (which primarily consist of smaller units) and

		lower than average costs for distribution substation refurbishments on a per transformer basis. • Hydro One has also introduced a lower cost unfenced pad mount transformer solution for replacement of smaller substations (where feasible), which most other utilities have not considered.
DSP Section 3.3, Attachment 2	Vegetation Management Program (UVM) Benchmarking - CN Utility	• Hydro One has an average program budget 2.5 times that of the Peer 2019 group (as defined in the report). This disparity is largely explained by Hydro One's unique and challenging UVM setting (i.e., similarly sized customer base as the Peer 2019 group but twice the distribution right-of-way kms). • With the implementation of the Optimal Cycle Protocol (or OCP, which began at the end of 2017), Hydro One's cost per managed right-of-way km has dropped over 50%, non-force majeure SAIDI trend has improved, and vegetation maintenance interval has dropped from 9.5 years to a projected first cycle of 4.1 years.
DSP Section 3.3, Attachment 3	Optimal Cycle Protocol – Clear Path Utility Solutions	• Sampling of OCP feeders showed a 96% improvement in vegetation defects (relative to 2017 survey, 0-2 year slot class). • An analysis of Tree Caused Outages comparing non-OCP feeders vs. OCP feeders showed an improvement of between 23% and 41%. • Workload (i.e., number of trees trimmed or removed under OCP) for 2018-2020 was 13% greater than 2017 modeled projections. Actual unit cost (per tree and per km) was significantly higher than 2017 modeled cost, due to factors that were not reasonably foreseeable at the time.
DSP Section 3.3, Attachment 5	Accelerated Life Testing of Meters - Hydro Quebec	• There were significant failures in GEN 1 meters involving the rapid degradation of capacitor C21. • Applying the study's GEN 1 meter findings (i.e., Time to Failure and Acceleration Factors) at the recommended confidence level of 50% results in projections of approximately 88% or 579,000 meters failing through 2027.
DSP Section 3.3, Attachment 6	AMI Replacement Costs Benchmarking - Guidehouse and First Quartile	• Hydro One's average meter acquisition cost ($160) is 10% higher than the mean of the comparator group ($145). Hydro One costs reflect contracted prices for low volume individual meter replacements and do not incorporate economies of scale that would be expected with bulk purchases. • Hydro One's average labour cost of $122 (excluding materials surcharge and overheads) per meter replaced is higher than the comparator average of $47. This is because Hydro One's costs reflect individual replacements rather than mass replacements, and because of the large, mostly low-density nature of Hydro One's service territory (i.e., lowest customer density out of the comparator group, 23 times less than its closest comparator).

DSP Section 3.3, Attachment 7	Billing and Call Center Costs Benchmarking - Information Services Group (ISG)	• Call Centre costs at Hydro One are below the market average. • Billing costs at Hydro One are towards the lower end of the market range. • Total Call Centre and Billing spend at Hydro One is 9% below the market average. • The number of Customer Service Representatives at Hydro One is below the peer group average. • The number of Billing FTEs at Hydro One is well below the peer group average.
GSP Section 4.3, Attachment 1	Fleet Operations Benchmarking Report - Utilimarc	• Hydro One ranked in the second quartile of comparator utilities based on cost per vehicle equivalency and cost per on-road vehicle, and in the first quartile in terms of cost per on-road vehicle km. • Of the comparator group, Hydro One has the lowest percentage of vehicles that are considered “low mileage”. Hydro One vehicles run 5,000 km higher on average than peers.
GSP Section 4.3, Attachment 2	Fleet Lifecycle Study - Utilimarc	• Based on the assessed funding scenarios, in order to keep the population of “out of life” vehicle assets at a manageable level and prevent significant escalations in maintenance costs, Utilimarc concluded that an increase in annual capital investment is needed to replace more units than historical capital funding levels allow.
GSP Section 4.3, Attachment 3	Enterprise IT Spending & Staffing Benchmark – Gartner	• Gartner found that, among other things, Hydro One allocated 31% of IT Spending to “Grow” and “Transform” activities (a 90% increase since the 2016 Gartner study), IT Spending per Employee was 17% less than the peer group average, and Hydro One relies more heavily on outsourcing than peers. • Gartner made various recommendations related to the appropriate IT investment levels and value of outsourcing arrangements.
C-08-02, Attachment 2	Capitalization of Common Corporate Costs Review - PwC	• Hydro One’s proposed methodology for capturing common corporate costs and allocating such costs to capital activities is reasonable, supportable and consistent with the principle that the assignment of such costs should be based on a causal link. • The methodology follows the guidance promulgated historically by the OEB and FERC and is consistent with the practice of other utilities that apply rate regulated accounting guidance under US GAAP and IFRS.
E-04-02, Attachment 1	Common Corporate Costs Benchmarking Study - UMS	• The overall finding is that Hydro One’s common corporate costs are very competitive with the Comparator Group. • Of the 9 functions benchmarked, 5 are at or near first quartile levels and 4 are at or near median levels.

E-06-01, Attachment 1	Compensation Benchmarking Study - Mercer	• When assessing compensation competitiveness, Mercer considers compensation levels to be competitive, on an overall/employee group basis, when it is within +/- 5% of the target market positioning, which is the median for Hydro One. Hydro One is positioned 4% above this competitive range; down (closer to market median) from 7% above the competitive range in the 2017 study. • Hydro One's overtime pay practices are, as a whole, generally aligned with or less generous than practices in the market. • The design (i.e. target incentive levels) of Hydro One's short-term incentive program is more aligned with the market median of the comparator group.

9.0 KEY FINANCIAL COMPONENTS

9.1 REVENUE REQUIREMENT

Hydro One has calculated its Transmission and Distribution revenue requirement using the approaches and methodologies that have been accepted in previous OEB proceedings, with exception to the treatment of its PCB Retirement and Waste Management program (the PCB Program) expenses in the determination of revenue requirement.

In this Application, Hydro One has proposed a different treatment of its PCB Program expenses to ensure that there is continued Sustainment OM&A funding in revenue requirement that corresponds to the Sustainment OM&A work required over the test period, namely to avoid an unwarranted reduction to OM&A expense after 2025 when the program ends. As discussed in Exhibit D-01-01, PCB costs are an OM&A related expenditure that was previously accounted for in the capital related revenue requirement through its recognition as a depreciation and amortization expense, but will now be reclassified back to OM&A.

For both Transmission and Distribution, the PCB Program will end in 2025 and will be replaced by other Sustainment OM&A work required to be undertaken over the remainder of the forecast period. See details on the proposed treatment of PCB Program costs in Exhibit D-01-01.

9.1.1 TRANSMISSION REVENUE REQUIREMENT

The requested 2023 total Transmission revenue requirement of $1,823.2M, as shown in Table 12 below, represents an increase of 0.9% (or about $15.6M) compared to the 2022 forecast. This increase is below the expected rate of inflation, and is predominantly driven by work that is necessary to achieve outcomes valued by customers, sustain safe and reliable transmission system operations, maintain equipment performance, and address system needs and service obligations. The increase is partially offset by reduced cost of capital and incremental productivity gains in 2023, as further described in SPF Section 1.4.

Table 12 - Transmission Revenue Requirement ($M)

Components	2020[1] Rebasing Year	2021[2]	2022[3]	2023 Rebasing Year	Reference
OM&A	385.0	-	-	420.5	Exhibit E-02-01
Environmental Provision addback to OM&A	-	-	-	7.6	Exhibit D-01-01
Depreciation and Amortization	473.4	-	-	535.8	Exhibit E-08-01
Environmental Provision reduction to Expense	-	-	-	-7.6	Exhibit D-01-01
Income Taxes	30.1	-	-	40.5	Exhibit E-09-02
Return on Capital	741.0	-	-	826.3	Exhibit F-01-01
Total Revenue Requirement	**1,629.6**	**1,704.3**	**1,807.6**	**1,823.2**	

**Exhibit Reference: D-01-01, Table 1*

Note 1: Represents OEB approved 2020 revenue requirement in EB-2019-0082
Note 2: Represents OEB approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0202
Note 3: 2022 Revenue Requirement = $1,704.3(2021 Revenue Requirement)(1 + (2.00% inflation factor - 0.30% stretch factor + 2.70% capital factor)) + $28.4(DTA Recovery) = $1,807.6. 2022 OEB approved revenue requirement to be established as part of the 2022 Annual Update.*

9.1.2 DISTRIBUTION REVENUE REQUIREMENT

The requested 2023 total Distribution revenue requirement of $1,632.4M, as shown in Table 13 below, represents a decrease of about 2.5% (or about $42.2M) compared to the 2022 forecast. This decrease is predominantly driven by certain benefits expected in 2023, such as a reduced cost of debt and incremental productivity gains, as further described in SPF Section 1.4. This decrease is partly offset by expenditures necessary to provide safe and reliable distribution of power and sufficient grid capacity to accommodate customer demand and to align with customer preferences, increases to OM&A due to the inclusion of OPEB non-service costs,[26] and the incremental revenue requirement related to the Acquired Utilities in 2023.

2023 revenue requirement includes an incremental amount of $30.0M related to the Acquired Utilities, which is not included in the 2022 OEB-approved forecast. If 2023 is adjusted to exclude this amount, which would provide for a more comparable analysis, then the decrease in revenue requirement relative to the forecasted 2022 OEB-approved amount results in a reduction of about 4.3% or about $72.2M.

[26] As directed by the OEB in EB-2019-0082.

Table 13 - Distribution Revenue Requirement ($M)

Components	2018[1] Rebasing Year	2019[1]	2020[2]	2021[3]	2022[4]	2023 Rebasing Year	Reference
OM&A	544.4	-	-	-	-	597.5	Exhibit E-03-01
Environmental Provision add-back to OM&A	-	-	-	-	-	5.5	Exhibit D-01-01
Depreciation and Amortization	397.8	-	-	-	-	465.6	Exhibit E-08-01
Environmental Provision reduction to Expense	-	-	-	-	-	-5.5	Exhibit D-01-01
Income Taxes	43.1	-	-	-	-	37.2	Exhibit E-09-02
Return on Capital	473.2	-	-	-	-	532.1	Exhibit F-01-01
Total Revenue Requirement	**1,458.5**	**1,497.9**	**1,539.2**	**1,596.2**	**1,674.6**	**1,632.4**	

**Exhibit Reference: D-01-01, Table 7*

Note 1: Represents OEB approved 2018 and 2019 revenue requirement in EB-2017-0049
Note 2: Represents OEB approved 2020 revenue requirement in 2020 Annual Update in EB-2019-0043
Note 3: Represents OEB approved 2021 revenue requirement in 2021 Annual Update in EB-2020-0030
Note 4: 2022 Revenue Requirement = $1,596.2(2021 Revenue Requirement)(1 + (2.20% inflation factor 0.45% stretch factor + 1.85% capital factor)) + $21.0(DTA Recovery) = $1,674.6. 2022 OEB approved revenue requirement to be established as part of the 2022 Annual Update.*

9.2 RATE BASE

The requested Transmission and Distribution rate base over the test period is provided in Table 14 below. The 2023 total Transmission rate base represents a $14,592.7M (7.0%) increase over 2022 OEB-approved levels. The 2023 total Distribution rate base represents a $9,372.0M (6.5%) increase over 2022 OEB-approved levels.

Table 14 – 2022 OEB-Approved and 2023-2027 Transmission and Distribution Rate Base ($M)

Description	OEB-Approved	Test				
	2022	2023	2024	2025	2026	2027
Transmission Rate Base	13,640.9	14,592.7	15,450.3	16,448.9	17,394.1	18,256.2
Distribution Rate Base	8,803.7	9,372.0	9,962.9	10,641.2	11,301.8	11,880.5

**Exhibit reference: C-1-1, Tables 2 and 3 (Transmission) and C-1-1, Tables 7 and 8 (Distribution)*

9.3 COST OF CAPITAL

The cost of capital and financing assumptions, as described in Exhibits F-01-01 and F-01-02, have been reflected in the 2023-2027 revenue requirements of this Application. Hydro One's Transmission and Distribution deemed capital structures for rate-making purposes are 60% debt and 40% common equity of utility rate base, consistent with the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, dated December 11, 2009 (EB-2009-0084). The 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt. Hydro One Inc.'s debt financing strategy takes into consideration the objectives of cost effectiveness, evenly distributed debt maturities over time, and alignment of the term of the debt portfolio with the long service lives of the Company's assets.

Hydro One anticipates updating the revenue requirements for the 2023 to 2027 test years as part of the Draft Rate Order process to reflect: (i) the OEB-approved 2023 return on equity and deemed short term debt rate; and (ii) long-term debt rates based on Hydro One's actual 2021 and 2022 debt issuances to-date and forecasted debt issues in 2023 with coupon rates based on the September 2022 Consensus Forecast.

Hydro One proposes that the 2023 cost of capital parameters be used to determine the final revenue requirement for 2023 to 2027 test years. The placeholder for Transmission and Distribution cost of capital parameters are set out in Tables 15 and 16, below.

Table 15 - Transmission Cost of Capital Parameters

	2023			
Particulars	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
	(a)	(b)	(c)	(d)
Long-term debt	7,873.7	54.0%	4.04%	318.3
Short-term debt	583.7	4.0%	1.56%	9.1
Deemed long-term debt	298.2	2.0%	4.04%	12.1
Total debt	8,755.6	60.0%	3.87%	339.5
Common equity	5,837.1	40.0%	8.34%	486.8
Total rate base	14,592.7	100.0%	5.66%	826.3

**Exhibit reference: F-01-03 (page 4)*

Table 16 - Distribution Cost of Capital Parameters

	2023			
Particulars	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
	(a)	(b)	(c)	(d)
Long-term debt	4,880.7	52.1%	4.07%	198.6
Short-term debt	374.9	4.0%	1.56%	5.8
Deemed long-term debt	367.7	3.9%	4.07%	15.0
Total debt	5,623.2	60.0%	3.90%	219.4
Common equity	3,748.8	40.0%	8.34%	312.7
Total rate base	9,372.0	100.0%	5.68%	532.1

**Exhibit reference: F-01-03 (page 3)*

9.4 DEFERRAL AND VARIANCE (DVA) ACCOUNTS

Accounts for Hydro One Transmission and Distribution, as well as the Acquired Utilities, have been cleared as of the following dates:

- Transmission DVA balances were cleared as of December 31, 2018 on a final basis (the Prior Transmission Application – EB-2019-0082)
- Distribution Group 1 DVA balances were cleared as of December 31, 2019 on a final basis (2021 annual update – EB-2020-0030)
- Distribution ESM balance was cleared as of December 31, 2019 on an interim basis (2021 annual update – EB-2020-0030)
- Distribution Group 2 DVA balances were cleared as of December 31, 2016 on a final basis (Prior Distribution Application – EB-2017-0049)
- The Acquired Utilities Group 1 DVA balances were cleared as of December 31, 2019 on a final basis (2021 annual update – EB-2020-0031)

Details are included in Exhibit G-01-01.

In this Application, Hydro One proposes to dispose of its DVA balances over a five-year period to align with the Custom IR term as follows:

- Transmission DVA balances as of December 31, 2020 on a final basis
- Distribution Group 1 and Group 2 DVA balances as of December 31, 2020, on a final basis. This includes the Group 1 account balances for the Acquired Utilities as of December 31, 2020.

Details are included in Exhibit G-01-01 and Exhibit G-01-04.

9.4.1 REGULATORY ACCOUNTS – TRANSMISSION

Hydro One requests approval to dispose of its audited 2020 balances on Transmission DVAs, totaling a debit balance of $5.6M inclusive of projected carrying charges to December 30, 2022. As set out in Exhibit G-01-02, Hydro One Transmission is requesting approval to continue or discontinue existing accounts, and to establish or modify the following accounts:

1. Capitalized Overheads Tax Variance Account (Transmission) (New) - to capture revenue requirement impacts arising from the adoption of a new approach on income tax by accelerating deductions of capitalized overheads for tax purposes
2. Externally Driven Transmission Projects Variance Account (New) - to record the revenue requirement impact, including tax, of variances between the in-service additions embedded in Hydro One’s approved revenue requirement relating to mandatory transmission construction, expansion, reinforcement, modification and relocation work required by governmental authorities, including indirectly through agencies, Crown corporations, or similar parties through regulation, policy changes or other official directives (Externally Driven Work) and the actual in-service additions arising from Externally Driven Work during the 2023-2027 period
3. Capital In Service Variance Account (CISVA) (Modification) – the modification would enable the balance in the account to be calculated yearly using the cumulative in-service additions over the Custom IR term so as to provide an opportunity for Hydro One to “catch-up” in later years within the term on any shortfalls in in-service additions that may occur in earlier years, and thereby to reverse the applicable impact recorded in a prior year of under in-servicing to the extent it makes up for such a shortfall
4. Rights Payments Variance Account (Modification) – the modification would enable the account to be used to capture amounts in relation to payments that Hydro One is required to make under Long Term Relationship Agreements or similar, regardless of how those payments are characterized or their form, so long as the payments are necessary for Hydro One to obtain the consents required to complete the transfer of title to Hydro One for the relevant lands
5. OPEB Asymmetrical Carrying Charge Variance Account (Modification) – the modification

consists of a new alternative methodology that responds to the OEB's previous findings and reflects OPEB costs in total depreciation expense based on reasonable assumptions

6. Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Tracking Account (Modification) - the modification is related to the modification of the OPEB Asymmetrical Carrying Charge Variance Account, and also consists of a new alternative methodology that responds to the OEB's previous findings and reflects OPEB costs in total depreciation expense based on reasonable assumptions

9.4.2 REGULATORY ACCOUNTS – DISTRIBUTION

Hydro One requests approval to dispose of its audited balances of Distribution DVAs, totalling a credit balance of $87.7M inclusive of projected carrying charges as at December 30, 2022. This is based on the clearance of a 2020 Group 1 credit balance of $69.5M, and a Group 2 credit balance of $18.1M (inclusive of projected carrying charges as at December 30, 2022).

As set out in Exhibit G-01-02, Hydro One Distribution is requesting approval to continue or discontinue existing accounts and to establish or modify the following new accounts:

1. Capitalized Overheads Tax Variance Account (Distribution) (New) - to capture revenue requirement impacts arising from the adoption of a new approach on income tax by accelerating deductions of capitalized overheads for tax purposes
2. Externally Driven Distribution Projects Variance Account (New) - to record the revenue requirement impact, including tax, of overspending or underspending relative to Hydro One's distribution capital investment plan which underlies the proposed revenue requirement for the 2023-2027 period, where such overspending or underspending is for work related to third-party initiated relocation, DER connections, or service upgrades, which Hydro One is required to undertake
3. Distribution Connection Cost Agreement (CCA) Variance Account (New) - to track the impacts on the Distribution revenue requirement of capital contribution true-ups paid by Hydro One Distribution to Hydro One Transmission and the capital contributions collected by Hydro One Distribution from its embedded distributors and large customers

4. AMI 2.0 Variance Account (New) - to record the difference between the revenue requirement associated with the planned in-service additions included in the forecasted cost of the AMI 2.0 program over the 2023-2027 period and the revenue requirement associated with the actual in-service additions achieved as part of the AMI 2.0 program over the 2023-2027 period
5. Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account (New) - to record the difference between the revenue requirement associated with asset removal cost forecasts that have been included in the proposed depreciation expenses for 2023-2027 and actual asset removal costs incurred in each of the test years, inclusive of tax
6. OPEB Asymmetrical Carrying Charge Variance Account (Modification) - the modification consists of a new alternative methodology that responds to the OEB’s previous findings and reflects OPEB costs in total depreciation expense based on reasonable assumptions
7. Pension and OPEB Forecast Accrual Versus Actual Cash Payment Differential Variance Tracking Account (Modification) - the modification is related to the modification of the OPEB Asymmetrical Carrying Charge Variance Account, and also consists of a new alternative methodology that responds to the OEB’s previous findings and reflects OPEB costs in total depreciation expense based on reasonable assumptions

10.0 CUSTOM IR PROPOSAL

The Application is based on a Custom IR approach for the 2023-2027 period. For each of Hydro One Transmission and Hydro One Distribution, the revenue requirement for the first year of the five-year period (2023) is determined using a cost of service, forward test year approach. For 2024-2027, Hydro One proposes 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 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, equal to the sum of Hydro One's custom Industry Total Factor Productivity measure and its custom stretch factor. The Productivity Factors of 0.3% for Hydro One Distribution and 0% for Hydro One Transmission are based on the recommendations of its independent expert, Clearspring Energy Advisors (Clearspring), and are calibrated to the results of the industry productivity trends and Clearspring's total cost benchmarking studies.

"C" is Hydro One's Custom Capital Factor, designed to recover incremental revenue each test year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.15%.

The supplemental stretch and X-factor will be applied in a cumulative manner in each year of the test period. This represents a change from Hydro One's previous Custom IR frameworks and results in a significant upfront revenue requirement reduction for customers.

A summary of the RCI components is provided in Table 17 and Table 18 below. Details of these components, and Clearspring's benchmarking results and recommendations used to inform the RCI, are found in Exhibits A-04-01 to A-04-03.

Table 17 - Revenue Cap Index Components – Transmission (%)

Custom Revenue Cap Index by Component	2024	2025	2026	2027
Inflation Factor (I)	2.00	2.00	2.00	2.00
Productivity Factor (X)	0.00	0.00	0.00	0.00
Capital Factor (C)*	4.29	2.63	3.56	1.68
Custom Revenue Cap Index Total	**6.29**	**4.63**	**5.56**	**3.68**

** Includes the supplemental stretch of 0.15% on capital.*

Table 18 - Revenue Cap Index Components – Distribution (%)

Custom Revenue Cap Index by Component	2024	2025	2026	2027
Inflation Factor (I)	2.20	2.20	2.20	2.20
Productivity Factor (X)	-0.30	-0.30	-0.30	-0.30
Capital Factor (C)*	2.93	2.41	3.48	2.56
Custom Revenue Cap Index Total	**4.83**	**4.31**	**5.38**	**4.46**

** Includes the supplemental stretch of 0.15% on capital.*

To further align Hydro One's interests with those of its customers and to provide additional elements of protection for customers, Hydro One is proposing the following additional features as part of its overall Custom IR framework for each of Hydro One Transmission and Hydro One Distribution:

- an ESM that will provide customers with a 50% share of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term;
- a CISVA to track the difference between: (i) the revenue requirement associated with actual in-service capital additions; and (ii) the revenue requirement associated with OEB-approved in-service capital additions, for any capital in-service additions that are lower than 98% of the OEB-approved level (with verifiable productivity savings being excluded to ensure that true productivity savings are incented through the Custom IR term). The CISVA proposal for Transmission includes a modification as described under Regulatory Accounts – Transmission above and detailed in Exhibit G-01-02; and

- Z-factor and off-ramp mechanisms that apply OEB-approved criteria.

Hydro One's proposed Custom IR framework aligns the utility's needs with the interests of and outcomes valued by its customers, and drives performance and continuous improvement in realizing those outcomes.

11.0 LOAD FORECAST

Hydro One's load and customer forecast methodology uses established industry practices and methods, such as econometric and end-use models, Conservation and Demand Management (CDM) inputs from the IESO, and weather normalization based on a 31-year average of relevant weather data. The forecast methodology has been used and approved by the OEB in Hydro One's Transmission and Distribution rate applications since 2006 and remains appropriate.

The load forecast uses actual 2020 amounts (peak, sales and number of customers) as the starting point, and includes consensus information available as of February 2021 for provincial/commercial/industrial GDP, population, housing starts, and disposable income forecasts over the application period. The load forecast also accounts for changes in electricity usage trends as well as significant growth due to developments in the Leamington area of southwestern Ontario.

A detailed description of the methodology and all of the inputs to the econometric and end-use models used for load forecasting are provided in Exhibits D-03-01 to D-05-01.

11.1 TRANSMISSION LOAD FORECAST

The monthly average transmission peak load is projected to grow at an average annual rate of 0.2% over the 2023-2027 period, largely driven by lower CDM assumptions, a higher housing starts consensus forecast, and growth related to developments in southwestern Ontario.

Table 19 - 2022-27 Weather-Normal Tx Forecast (Net of CDM and Embedded Generation)

	2022	2023	2024	2025	2026	2027
Average Monthly Peak (MW) – OEB Approved	19,543					
Average Monthly Peak (MW) – Forecast	19,381	19,451	19,527	19,547	19,584	19,607
% change over prior year	+0.2%	+0.4%	+0.4%	+0.1%	+0.2%	+0.1%

The transmission load forecast was last approved by the OEB in 2020 for the 2020 to 2022 period. Resetting of the current OEB-approved 2022 forecast as proposed in this Application is estimated to contribute to a 0.6% increase in transmission rates in 2023, while increasing peak demand over the remainder of the Application period is expected to result in an average decrease in transmission rates of 0.2% per year.

11.2 DISTRIBUTION LOAD AND CUSTOMER FORECAST

Distribution load is projected to grow by 2.7% in 2023 as a result of including the Acquired Utilities as part of Hydro One’s forecast, and is projected to grow at an average rate of 0.3% over the 2024-2027 period. The number of customers is expected to grow by 5.3% in 2023 as a result of including the Acquired Utilities as part of Hydro One’s forecast, and it is expected to grow at an average of 0.7% over the 2024-2027 period. In addition to growth driven by including the Acquired Utilities in Hydro One’s load forecast, the expected load growth over the Application period is driven by lower CDM assumptions, a higher housing starts consensus forecast and growth related to developments in southwestern Ontario.

Table 20 - 2022-27 Weather-Normal Dx Forecast (Net of CDM and Embedded Generation)

	2022	2023	2024	2025	2026	2027
Sales (GWh) – OEB Approved	32,593					
Sales (GWh) – Forecast	32,912	33,807	33,921	34,030	34,136	34,239
% change over prior year		2.7%	0.3%	0.3%	0.3%	0.3%
Customer # (M) - OEB Approved	1.334					
Customer # (M)[27] – Forecast	1.343	1.414	1.424	1.434	1.444	1.453
% change over prior year		+5.3%	+0.7%	+0.7%	+0.7%	+0.6%

Hydro One's distribution load forecast was last approved by the OEB in 2019 for the 2018 to 2022 period. Due to the large share of Distribution revenue collected from fixed charges, and the fact that the number of customers is forecast to increase relative to the OEB-approved number of customers for 2022, resetting the distribution forecast in the current Application is expected to contribute to a decrease in rates of about 1.4%[28] in 2023 and a further decrease of approximately 0.6% in each of the subsequent years of the Application period.

12.0 COST ALLOCATION AND RATE DESIGN

12.1 TRANSMISSION COST ALLOCATION AND RATE DESIGN

Hydro One continues to follow the methodology, approved by the OEB since 2006, to allocate its transmission rates revenue requirement into three rate pools (Network, Line Connection and Transformation Connection). That methodology is described in Exhibits H-01-02 and H-01-03. Hydro One's transmission rates revenue requirement, allocated by rate pool, is used as an input to the calculation of UTRs as detailed in Exhibit H-06-01.

[27] Number of customers is mid-year.

[28] This does not include the impact on rates due to the inclusion of the Acquired Utilities, which will be largely offset by the inclusion of the Acquired Utilities revenue requirement starting in 2023.

12.2 DISTRIBUTION COST ALLOCATION

Hydro One has prepared its cost allocation evidence in accordance with Chapter 2 of the Distribution Filing Requirements and using the latest cost allocation model from the OEB.

This Application includes the creation of new rate classes for customers from the three Acquired Utilities and an added option for customers in relation to the Sub-Transmission rate class.[29] Aside from changes related to these new items, the cost allocation process follows the process previously approved by the OEB for Hydro One Distribution.

12.2.1 NEW ACQUIRED CLASSES

Hydro One proposes to make a number of changes effective January 1, 2023 in relation to the rate classification of customers from the Acquired Utilities. These changes include establishing two new sets of rate classes into which residential and general service customers of the Acquired Utilities will be placed, as described in Exhibit L-01-02. Acquired Utilities customers in the Street Lights, Sentinel Lights, Unmetered Scattered Load and Large User classes will be merged into corresponding Hydro One rate classes starting in 2023.

Hydro One's total 2023 Distribution revenue requirement, including all shared/common costs, will be allocated to legacy Hydro One rate classes and the new rate classes for the Acquired Utilities on the same basis using the cost allocation principles embedded with the OEB's cost allocation model.

As detailed in Exhibit L-03-01, the results from the cost allocation and rate design process show that $32.8M is proposed to be collected from customers of the Acquired Utilities in 2023, which is less than the $42.2M that would have otherwise have been collected from them in 2023 in the

---

[29] This Application also implements the OEB's previously approved decision to eliminate the Seasonal class. Implementation of the Seasonal class elimination is being addressed in an on-going separate proceeding (EB-2020-0246). This Application assumes an implementation date of January 1, 2023 for eliminating the Seasonal rate class.

absence of the transactions, representing a benefit to those customers of $9.4M or a 22% reduction in the total revenue requirement that would otherwise have been collected from them. Moreover, the $32.8M to be collected from customers of the Acquired Utilities in 2023 is greater than the $30.9M in Hydro One's incremental revenue requirement associated with serving those customers. This represents a benefit to Hydro One's legacy customers as it results in a $1.9M reduction in the revenue that would otherwise have been collected from Hydro One's legacy customers in the absence of the transactions. This demonstrates that the acquisitions resulted in a benefit for both legacy and the Acquired Utilities' customers.

12.3 DISTRIBUTION RATE DESIGN

This Application continues the OEB-mandated move to all-fixed residential distribution rates for Hydro One's Medium-Density (R1) and Low-Density (R2) residential rate classes, who will complete their transition to all-fixed rates in 2024. The transition to all-fixed rates for Hydro One's High Density Residential (UR) class was completed in 2021.

As described in Exhibit L-02-01, this Application also proposes to remove the requirement for ST customers to own their local transformation, and to instead provide such customers with the option to pay a transformer charge if they meet all of the other requirements of the ST class and prefer to be connected to Hydro One local transformers. This change responds to customer feedback and preference for having the utility be responsible for all elements of its distribution connection and aligns with the approach to transformer ownership taken by other utilities.

13.0 BILL IMPACTS

Whether in respect of Transmission or Distribution, the average impact on customer rates is driven by changes to the proposed revenue requirement and the load forecast[30] over the Application period, as well as impacts from the disposition of regulatory accounts. The impacts

---

[30] Load forecast refers to the forecast of energy consumption, peak demands and number of customers.

on individual distribution customers within different rate classes will depend on the outcome of the cost allocation and rate design process, as well as the load forecast by rate class.[31]

Exhibits H-10-1 and L-06-01 provide the bill impacts that will result from approval of the Application for the Transmission and Distribution businesses, respectively.

13.1 TRANSMISSION BILL IMPACTS

Table 21 shows the estimated average bill impacts of the proposed changes in Hydro One's transmission rates revenue requirement and load forecast on transmission and distribution connected customers over the Application period.

Table 21 - Average Rate and Bill Impacts on Transmission and Distribution-connected Customers

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2023-2027 Average**
Revenue Requirement ($M)	**1807.6**	**1,823.2**	**1,937.8**	**2,027.5**	**2,140.3**	**2,219.0**	
Adjustments to Revenue Requirement ($M) (Note 1)	**71.2**	**(16.4)**	**(54.7)**	**(54.4)**	**(53.1)**	**(53.5)**	
Rates Revenue Requirement ($M)	1,878.8	1,806.8	1,883.1	1,973.1	2,087.2	2,165.5	
% Change over prior year		-3.8%	4.2%	4.8%	5.8%	3.8%	2.9%
Estimated Load Impact on Rates		0.6%	-0.4%	-0.1%	-0.2%	-0.1%	-0.05%
Estimated Impact on Transmission Rates (Note 2)		-3.1%	3.6%	4.4%	5.3%	3.4%	2.7%
Average Transmission Customer Bill Impact		-0.2%	0.3%	0.3%	0.4%	0.3%	0.2%
Average Distribution Customer Bill Impact		-0.2%	0.2%	0.3%	0.3%	0.2%	0.2%

Note 1: Adjustments include non-rate revenues, export revenues, disposition of regulatory accounts and low voltage switchgear credit. For purpose of estimating rate impacts, adjustments also include historical misallocated Future Tax Savings amounts being recovered in 2022 (+$87.1) and 2023 (+$43.5) per the OEB Decision in proceeding EB-2020-0194.
Note 2: The calculation of net impact on transmission rates accounts for Hydro One's revenue disbursement allocation factor of 94.2% as approved for 2021 UTR Revenue Requirement (EB-2020-0251) issued on December 17, 2020.

---

[31] In the case of transmission, the impacts will vary depending on the type of services used by transmission customers (i.e. Network, Line Connection, Transformation Connection), and the forecast charge determinants for those services.

The impact on Transmission rates of Hydro One's transmission-related proposals in this Application is estimated to be a reduction of 3.1% in 2023 followed by small annual increases, resulting in an average annual increase of 2.7% over the Application period. This translates into average bill impacts on both transmission and distribution end-use customers of a decrease of 0.2% in 2023 followed by small increases in subsequent years, resulting in a 0.2% average annual increase over the Application period.

13.2 DISTRIBUTION BILL IMPACTS

The impact on individual distribution customer bills by rate class results from the cost allocation and rate design process, as well as the disposition of regulatory accounts. Table 22 summarizes the 2023-2027 total bill impacts for typical customers in all customer classes resulting from Hydro One's distribution-related proposals in this Application. Bill impacts across a range of consumption levels are provided in Exhibit L-06-01.

Table 22 - 2023-2027 Total Bill Impacts for Typical Customers in all Customer Classes

	2023		2024		2025		2026		2027	
Rate Class	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
UR	($2.58)	-2.0%	$0.75	0.6%	$1.38	1.1%	$1.86	1.4%	$1.58	1.2%
R1 (with DRP)	($0.95)	-0.7%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
R1 (without DRP)	($2.78)	-1.8%	$1.40	0.9%	$2.36	1.5%	$3.18	2.0%	$2.26	1.4%
R2 (with DRP)	($1.10)	-0.8%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
R2 (without DRP)	($17.09)	-9.8%	$3.15	2.0%	$4.78	3.0%	$6.46	3.9%	$5.47	3.2%
Seasonal-UR	($33.11)	-29.0%								
Seasonal-R1	($10.31)	-9.0%								
Seasonal-R2	$49.65	43.5%								
GSe	($8.32)	-2.0%	$1.43	0.4%	$6.12	1.5%	$8.38	2.0%	$6.99	1.7%
UGe	($4.66)	-1.4%	$0.72	0.2%	$3.28	1.0%	$4.53	1.4%	$3.77	1.1%
GSd	($128.84)	-1.6%	$0.45	0.0%	$97.49	1.2%	$131.49	1.6%	$111.48	1.3%
UGd	($90.49)	-1.1%	$0.79	0.0%	$58.25	0.7%	$78.55	0.9%	$66.61	0.8%
St Lgt	($7.99)	-2.7%	$0.71	0.2%	$5.36	1.8%	$7.20	2.4%	$6.09	2.0%
Sen Lgt	($1.00)	-5.8%	($0.13)	-0.8%	$0.40	2.5%	$0.54	3.3%	$0.46	2.7%
USL	($6.90)	-6.5%	$0.36	0.4%	$1.09	1.1%	$1.78	1.8%	$1.90	1.9%
DGen	($17.96)	-2.7%	$12.54	2.0%	$14.53	2.2%	$19.59	3.0%	$16.69	2.4%
ST	($2,071.03)	-0.9%	$83.15	0.0%	$256.89	0.1%	$346.26	0.2%	$608.83	0.3%
Former Woodstock Hydro Customers to Hydro One Rate Classes										
AUR	($1.02)	-0.8%	$1.24	1.0%	$1.14	0.9%	$1.53	1.2%	$1.30	1.0%
AUGe	($7.70)	-2.6%	$2.23	0.8%	$2.12	0.7%	$2.89	1.0%	$2.37	0.8%
AUGd	($372.04)	-4.4%	$23.28	0.3%	$26.46	0.3%	$29.07	0.4%	$30.97	0.4%
St Lgt	$235.22	2.3%	$197.04	1.9%	$184.46	1.8%	$247.35	2.3%	$209.61	1.9%
USL	$35.98	18.8%	$1.98	0.9%	$1.50	0.7%	$2.52	1.1%	$2.64	1.1%
ST	($1,667.22)	-1.0%	$319.45	0.2%	$293.43	0.2%	$395.34	0.2%	$694.63	0.4%
Former Norfolk Power Customers to Hydro One Rate Classes										
AR	$0.90	0.7%	$1.51	1.2%	$1.38	1.1%	$1.86	1.4%	$1.58	1.2%
AGSe	($7.43)	-2.3%	$3.14	1.0%	$2.64	0.8%	$3.67	1.2%	$3.13	1.0%
AGSd	($197.47)	-1.6%	$56.24	0.5%	$52.59	0.4%	$69.30	0.6%	$63.33	0.5%
St Lgt	$227.41	9.5%	$50.46	1.9%	$47.24	1.8%	$63.35	2.3%	$53.68	1.9%
Sen Lgt	$5.64	22.3%	$0.84	2.7%	$0.76	2.4%	$1.03	3.2%	$0.88	2.6%
USL	$30.26	23.5%	$1.69	1.1%	$1.29	0.8%	$2.14	1.3%	$2.26	1.4%
Former Haldimand County Hydro Customers to Hydro One Rate Classes										
AR	$0.88	0.7%	$1.51	1.2%	$1.38	1.1%	$1.86	1.4%	$1.58	1.2%
AGSe	$4.66	1.5%	$3.14	1.0%	$2.64	0.8%	$3.67	1.2%	$3.13	1.0%
AGSd	($230.14)	-2.2%	$54.64	0.5%	$51.08	0.5%	$67.33	0.7%	$61.50	0.6%
St Lgt	($2,331.62)	-21.3%	$164.76	1.9%	$154.24	1.8%	$206.83	2.3%	$175.27	1.9%
Sen Lgt	($9.45)	-33.5%	$0.52	2.8%	$0.48	2.5%	$0.64	3.2%	$0.54	2.7%
USL	$22.12	29.6%	$1.40	1.4%	$1.09	1.1%	$1.77	1.8%	$1.90	1.9%

Note 1: *In 2024 to 2027, customers of R1 and R2 rate classes will be fully protected by the DRP credit against any changes in distribution rates and will not see any year-over-year change in their distribution charges.*

Note 2: *2024 to 2027 Seasonal customers' bill impact not available as the Seasonal rate class has been eliminated in 2023*

Note 3: *Hydro One proposes mitigation plans by way of a bill credit to be applied to each affected customer for any rate classes that are expected to experience total bill impacts greater than 10%, as discussed in Exhibit L-06-01.*

14.0 CONCLUSION

The proposed revenue requirements for the Transmission and Distribution business segments are appropriate and will enable Hydro One to deliver significant value to ratepayers through efficient, safe and reliable operations, as well as appropriately prioritized and reasonably paced investments in the Transmission System, Distribution System and General Plant. Moreover, the proposed Custom IR framework will effectively drive Hydro One to continuously improve its productivity and performance.

This page left blank intentionally.

Hydro One Networks Inc.

Joint Rate Application Business Plan

2023-27

May 7, 2021

Table of Contents

Executive Summary

Key Plan Highlights

Aligns with the Ontario Energy Board's incentive rate-setting requirements & Renewed Regulatory Framework Outcomes

The Plan reflects a Custom Incentive Rate-setting proposal, **aligned** with the objectives under the **Ontario Energy Board's Renewed Regulatory Framework**.

The Plan includes a productivity factor, a supplemental stretch on capital, and an Earnings Sharing Mechanism in support of achieving continuous productivity. The Plan also includes a Capital In-Service Variance Account, holding Hydro One accountable to deliver the capital plan and protecting customers.

2023 rates revenue requirement **reductions** of 0.4% in Transmission and 6.3% in Distribution, which include the impacts of load. Over the 5-year Plan, the average annual increase to a typical R1 Residential Customer is 0.3% in Transmission and 0.7% for Distribution. **Combined, these impacts are below the rate of inflation.**

Aligned with Customer Preferences

The Transmission and Distribution Plans **reflect customer needs and preferences** identified through a comprehensive **two-phase customer engagement process.** The Investment and Business Planning, regulatory, and customer engagement processes were fully integrated, allowing Hydro One to develop final system plans that are responsive to customer needs.

Supports the Company's Strategic Objectives and Outcomes

The Plan supports achievement of the desired outcomes established as part of the Corporate Strategic Plan:

- A more **reliable** and **sustainable** grid that enables customer benefits;
- An improved **safety** culture and reduction in serious injury rates for employees;
- Being a **trusted partner** with Indigenous Peoples, customers, communities, government and industry partners;
- Improving **customer** satisfaction over the Plan period; and
- Delivering on **incremental productivity savings**, in alignment with incentive rate making.

Responsible & Prudent Investments

The Plan reflects a continued commitment to exceptional customer service, safety, reliability, efficiency, resiliency and sustainability in both Transmission and Distribution businesses.

2023-27 average annual capital investments of $1.5 billion and $1.0 billion in Transmission and Distribution, respectively.

Transmission investments will **maintain** top tier reliability performance, **mitigate** safety and environmental risks, and **address asset condition**.

Distribution investments will enable local and regional growth and **modernize the grid** by incorporating new technologies consistent with leading industry trends to **improve** reliability while reducing costs.

Aligns with Ontario Energy Board Feedback & Directives

The Plan and rate application are **responsive** to the twenty (20) **Ontario Energy Board directives** arising from the last transmission application (EB-2019-0082) and the nineteen (19) directives arising from the last distribution application (EB-2017-0049).

Supported by Extensive Expert Reports

Informed by the results of benchmarking and external expert reviews including on productivity, corporate costs, capitalization practices, depreciation rates, compensation benchmarking, transmission execution process and performance, certain asset replacement rates and unit costs, and distribution vegetation management performance, among others.

The Business Plan (the "Plan") process at Hydro One Ltd. ("Hydro One" or the "Company") is a robust exercise that is typically conducted annually and presented for approval in December. For 2021, the Plan is being presented to the Board of Directors ("Board") in May to ensure that results of Phase 2 Customer Engagement are fully reflected, as this Plan will underpin the 2023-27 Joint Rate Application "JRAP" or "Application". The main objective is to execute a process that supports the Company's strategic objectives and values, and aligns to the Ontario Energy Board's ("OEB") Renewed Regulatory Framework ("RRF").

The Application framework aligns directly to the RRF. Hydro One has calculated the revenue requirement using the approaches and methodologies accepted in prior OEB proceedings. The Application will be based on a Custom Incentive Rate-Setting ("CIR") approach for a 5-year period. The Application contains a productivity factor, a supplemental stretch factor on capital, and an Earnings Sharing Mechanism ("ESM") in support of achieving continuous productivity, for each of the Transmission ("Tx") and Distribution ("Dx") businesses. Also, the Application includes a Capital In-Service Variance Account ("CISVA") for each of the Tx and Dx businesses to protect customers in the event that Hydro One is unable to materially deliver on its capital plan.

The Plan and JRAP align directly to the Corporate Strategic Plan. In 2019, the Board approved a five-year Corporate Strategic Plan ("Corporate Strategy") which established targets and set five strategic priorities to drive improved business outcomes. In this Plan, the targets have been extended to the end of 2027 to align with the JRAP rate period. The Plan will result in a more reliable Tx and Dx grid, strong relationships with communities including Indigenous communities, stakeholders, and the government, advocacy for Hydro One's customers, and a Company that is one of the safest and most efficient utilities in North America.

The Plan and JRAP reflect the needs and preferences of customers. Hydro One took additional steps to identify and address customer needs and preferences in preparation for its 2023–27 Investment Plan and the JRAP. The Company employed a two-phased approach, engaging customers at the beginning of the planning process, and again after a draft Investment Plan was prepared. This approach allowed Hydro One to develop an Investment Plan that is based on and responsive to customer input, and refined based on trade-offs between specific investment costs, outcomes, and rate impacts. This is the most comprehensive customer engagement process that Hydro One has ever undertaken. In total, over 48,000 customers participated in the engagement through various types of activities, including focus groups, in-depth interviews, telephone surveys, and online workbooks.

Capital expenditures are underpinned by asset needs and customer preferences. The Investment Plan reflects its commitment to exceptional customer service, safety, reliability, efficiency, resiliency and sustainability. Hydro One will plan, design and build a grid for the future by focusing on prudent investments in Ontario's electricity grid. The Plan reflects an ongoing focus on addressing poor condition and at-risk assets while preventing further degradation and improving the overall health of the asset fleet. This approach to proactive asset management and system investment aligns with the clear message from customers that they expect Hydro One to be a good steward of the electricity system and to make investments necessary to maintain a resilient and sustainable electricity grid. Capital expenditures are supported by the Transmission, Distribution and General Plant System Plans, with average annual capital investments over the 5-year period of $1.5 billion and $1.0 billion, in Tx and Dx, in 2023-27.

Growth in the Plan and JRAP is underpinned by a robust execution strategy. Hydro One has demonstrated the ability to execute its large and complex portfolio of investments and reduce the variability of its capital work on both Tx and Dx systems, by achieving annual in-service additions largely within +/-2% of to OEB approved levels between 2018 and 2020. To execute and deliver the growing work program during the Plan, the Company has developed a robust work execution strategy which includes a flexible workforce strategy, a continued focus on productivity that will increase work efficiency, and the execution of technology enhancements that will modernize tools and processes adopted in the delivery of work programs.

The Plan and JRAP also include an assessment of circumstances, challenges and other issues affecting planned investments. The planning and operation of Hydro One's Dx and Tx systems are complex, with numerous challenges and system pressures. These include the continued need to address verified poor condition assets at risk of failure, accommodating load growth to support economic development in Ontario, and building grid resiliency against climate change. The Company plans to respond to these system pressures and achieve productivity improvements while ensuring employee safety, maintaining and improving system reliability that provides 94% of Ontario's Tx capacity and delivers power to approximately 1.4 million Dx customers. The Plan assumes by 2023, material operational impacts of COVID-19 will have passed, and thus no incremental costs have been planned. However, in 2021, Hydro One is still experiencing incremental costs mostly associated with janitorial services, pandemic supplies, and rentals supporting increased fleet requirements for safe operations.

The Application balances investments against the impact on costs to customers. For 2023, rate revenue requirement reductions, including load, of 6.3% and 0.4% for Dx and Tx, respectively, will be proposed. This translates to an estimated 1.9% and 0.0% bill reduction for Dx and Tx, respectively, for a typical Hydro One R1 Residential Customer in the first year of the Plan period. Reductions relate to sustained productivity, regulatory account dispositions including sharing of past over-earnings, a lower cost of debt, and increased tax deductions. Over the full Plan, the average annual increase to a typical Hydro One R1 Residential Customer is 0.7% for Dx, and 0.3% for Tx. Combined, this is below the rate of inflation[1]. In addition to rate reductions in 2023, increases thereafter support inflationary increases to Operations, Maintenance and Administration costs ("OM&A"), and increases in capital expenditures to support investments underpinned by customer engagement and asset needs.

The Application is supported by third party expert reports. Hydro One has commissioned numerous third party expert reports to support the JRAP, including benchmarking on the productivity framework, corporate costs, capitalization practices, depreciation rates, compensation, Tx capital project execution process, certain asset replacement rates and unit costs, Dx vegetation management performance, and export transmission rates. Where necessary or appropriate, Hydro One has adjusted the Plan to reflect the recommendations made in the reports.

[1] Inflation forecast based on Canadian Price Index forecast by IHS Global Insight as of February 2021.

Hydro One's Strategy

The Company developed a Corporate Strategic Plan in 2019. As an input to the Plan supporting JRAP, the Corporate Strategy targets have been extended out to 2027. The Corporate Strategy focuses on what matters to customers, communities, stakeholders and investors: an unwavering commitment to exceptional customer service and needs, safety, innovation, efficiency and sustainability. The Corporate Strategy was influenced by several key factors and involved engagement and input across each line of business ("LoB") and the Board. The viewpoints of a broad spectrum of stakeholders were key inputs to the development process and implementation, which included an understanding of Hydro One's current operating context and performance against targets, outcomes under the OEB's RRF, and industry trends.

The company is focused on the implementation of the established strategic priorities, as shown below, supported by three enablers and the desired outcome under each strategic priority.

1. **Grid for the future:** Hydro One will continue to improve its core Tx and Dx business. Excellence in execution requires adopting new technologies to maintain top tier Tx reliability performance and improve long-term Tx and Dx reliability, while ensuring public policy responsiveness by lowering Hydro One's environmental footprint.
2. **Safest and most efficient utility:** Executing on Hydro One's core business by focusing on the achievement of continuous improvement to enhance operational effectiveness through efficiency and productivity, while achieving top-tier safety performance and eliminating serious injuries. Focusing on the essentials of safety and efficiency will also empower the workforce to better serve customers.
3. **Trusted partner:** Hydro One will continue to build relationships with communities and stakeholders, to earn their trust. Key stakeholders continue to expect improved reliability, safety, exceptional customer service, efficiency, and affordability. Hydro One will continue to proactively engage with the OEB, provincial and federal governments, and customers.
4. **Advocate for our customers:** Maintaining customer focus across the business, and enhancing the customer experience through advancements in technology, will enable Hydro One to engage proactively, and also improve and maintain satisfaction.

5. **Innovate and grow the business:** Hydro One will continue to develop its commercially-focused skillset, paving the way for further growth within Ontario. With over 150,000 new residents each year and an aging infrastructure, growth opportunities exist to improve reliability for customers and deliver greater value for all stakeholders.

Hydro One's Corporate Strategy guides the Company by setting outcome measures and targets, which are directly aligned with the OEB's RRF, as identified below.

RRF Outcomes	Business Objectives	Plan Outcomes and Targets
Customer Focus	**Customer Satisfaction**	▪ Improve and maintain Small Business & Residential Satisfaction at 87% in Dx ▪ Maintain Overall Customer Satisfaction of 88% in Tx through 2027
	Customer Focus	▪ Engage with customers consistently and proactively ▪ Identify and respond to customer needs and preferences ▪ Achieve Gold Level Certification under the Canadian Council for Aboriginal Business Progressive Aboriginal Relations Program by 2024 and sustain through 2027
Operational Effectiveness	**Safety**	▪ Achieve top-tier safety performance and eliminate life-altering injuries and fatalities ▪ Reduce serious injury frequency to 0 by 2024, and maintain at 0 ▪ Sustain recordable injurie rate below 1.0
	Cost Control	▪ Focus on continuous improvement to enhance efficiency, productivity, and reliability ▪ Achieve annual incremental productivity of $50mm
	Employee Engagement	▪ Achieve and maintain employee engagement
	System Reliability	▪ Maintain top tier Tx reliability performance and improve long-term Tx and Dx reliability ▪ Target Dx System Average Interruption Duration Index ("SAIDI") reliability results to 4.2 hours by 2027 ▪ Target Tx SAIDI to 7.0 minutes by 2027
Public Policy Responsiveness	**Public Policy Responsiveness**	▪ Deliver on obligations mandated by government through legislation and regulatory requirements
	Environment	▪ Lower Hydro One's environmental footprint through greenhouse gas emission reduction
Financial Performance	**Financial Performance**	▪ Responsible investment in rate base assets to ensure the safety and reliability of the grid ▪ Manageable and stable rate impacts through the Plan period

Performance Reporting Governance Framework

Hydro One's Performance Reporting Governance Framework establishes the process by which the company reports and develops measures and targets within the regulatory scorecards for its Distribution and Transmission segments. As part of the framework, and under the accountability of the Company's Chief Operating Officer, the Executive Leadership Team approves the final measures and targets for the regulatory scorecards. This framework will be applied in development of the regulatory scorecards for the JRAP period of 2023-27, to be included in the Application.

Health and Safety

Hydro One is committed to creating a Better and Brighter Future for All. "Safety Comes First" is one of Hydro One's core values, which guides the Company to work with employees to achieve world-class health and safety performance. Hydro One also recognizes the power to improve people's lives, including employees, customers, Indigenous Peoples, and communities in which the Company operates.

Hydro One prioritizes the health and safety of its employees. This includes creating an incident free workplace and continuously improving the Company's Health, Safety & Environment Management System. Consistent with the Corporate Strategy, Hydro One is committed to eliminating life-altering injuries and fatalities.

In early 2020, a Safety Improvement Team was created to understand the barriers that prevent a strong safety culture and to help end serious injuries and fatalities. A cross-functional, grassroots team of 18 employees with diverse roles and experiences was assembled. After conducting hundreds of interviews with more than 4,000 front line employees over more than 250 field visits, and conducting interviews with more than 15 external organizations, the Team developed 11 key recommendations to transform Hydro One's safety culture.

These recommendations have been incorporated into Hydro One's multi-year Safety Improvement Plan, which will be implemented over the next several years. Implementation will be carried out by a newly established Safety Office, which will heighten accountability and ensure consistent and collaborative leadership throughout the Company. These organizational changes will allow employees to work as one team in surmounting the Company's safety challenges and aligning with strategic objectives.

In short, the Company will build around the following five pillars to improve its safety culture:

- Enhance the Company's Safety Culture;
- Strengthen the Safety Management System;
- Establish a Safety Centre of Excellence;
- Improve apprentice safety; and
- Learn and Implement industry best practices.

Hydro One has made tremendous progress in reducing the rate of recordable injuries, which is a standardized safety calculation used to compare safety performance amongst companies. Hydro One's recordable injuries have declined by approximately 90% over the past ten years. More importantly, the recordable injury rate is now below 1.0, which is considered world-class among peer utilities. The Company is committed to eliminating life-altering injuries and fatalities by 2024 and through the rest of the Plan, as shown in the trajectory to target for the key measures below. While the improvement of recordable injuries is encouraging, the number of life-altering injuries and fatalities has been increasing (as reported via the Serious Injury and Fatality Rate).

Key Measures

Recordable Rate and Serious Injury and Fatality Rate

(Incidents per 200,000 hours worked)

Year	2019 Actuals	2020 Actuals	2021 Target	2022 Target	2023 Target	2024 Target	2025 Target	2026 Target	2027 Target
Recordable Injury Rate	0.78	0.87	0.92	0.90	0.90	0.90	0.90	0.90	0.90
Serious Injury and Fatality Rate	0.18	0.21	0.11	0.08	0.04	0	0	0	0

All Hydro One employees will work together to deliver the Plan, and each member of the team will have a role to play in bringing all employees home safe, every day. Safety will continue to be paramount in executing the work program. The Plan includes capital growth, which may require new front-line employees to join the workforce, some of whom may have limited experience. Regardless of the level of growth, work will be executed safely, with a continued focus on Apprentice Safety (as per the Safety Improvement Team's recommendations). The following safety initiatives are underway and will be an important focus of our journey over the next several years:

- Improving control-effectiveness to reduce risk;
- Adopting the Edison Electric Institute incident rating system;
- Implementing safety absolutes based on our risk register;
- Acquiring the best talent and developing employees;
- Improving the effectiveness of work safety observations, including pre-job planning, post-job review, and on-site supervision;
- Safeguarding Hydro One's apprentices;
- Conducting effective investigations and implementing impactful corrective actions;
- Developing robust safety analytics capabilities to target emerging risks; and
- Placing a greater focus on the Human Success program, which identifies situations in which potential errors could result in a workplace injury, a customer interruption, or damage to assets and equipment, and recommends tools and behaviours to help minimize the likelihood of such errors.

Maintaining public safety is also of critical importance and is a key factor in the asset management and Investment Planning process. For more information on safety related investments, please refer to the Investment Plan section on page 21.

Application Framework & Rate Changes

The revenue requirement for both Transmission and Distribution have been calculated using methodologies that are consistent with the RRF and which have largely been accepted by the OEB in prior proceedings. The Application is based on a CIR approach for a 5-year period. Revenue requirement in the first year, 2023, is determined using a forward test year cost of service approach. The revenue requirement in the following four years is equal to the prior year inflated by a custom Revenue Cap Index ("RCI") for the given year.

The RCI includes an inflation factor, a productivity factor, a capital factor and a supplemental stretch factor on capital for each of Tx and Dx. Inflationary increases are offset by the productivity and stretch factors, which act as an incentive for Hydro One to achieve productivity improvements. As will be discussed in the Productivity Savings section on page 56, the Company plans to utilize its internal Productivity Framework to target the productivity factor and the supplemental stretch on capital as set out in the CIR framework. The custom capital factor is designed to allow the Company to recover incremental revenue that supports the necessary capital investments, beyond the revenue recovered from the inflationary increase as offset by the productivity and stretch factors.

In the prior transmission application (EB-2019-0082), Hydro One applied progressive productivity as an additional bottom line reduction to its capital envelope and the associated in-service additions to represent undefined productivity the Company would strive to achieve, over and above the defined initiatives that were already embedded in operations and the capital plan. The OEB recognized that the productivity framework would improve Hydro One's planning processes, but that this would not be tested until the next rebasing application (i.e., the JRAP). In this application, Hydro One will revise its approach in two ways to clarify how the Productivity Framework benefits customers. First, instead of applying an additional bottom line reduction to the capital envelope, Hydro One will achieve its progressive productivity targets in consideration of the CIR framework productivity factor and supplemental stretch on capital. This approach provides an upfront revenue requirement reduction to customers. Second, Hydro One will propose that the productivity factor and the supplemental stretch factor on capital be applied in a cumulative manner.

The tables below outline revenue requirement and rate change estimates for each of Transmission and Distribution. Figures presented represent forecast amounts included in the initially filed evidence, which may be updated during the application process. The impact of the forecast updates are referenced in the "Forecasting Potential Filing Updates" table on page 11[1]. Also, as the OEB's decision on the Deferred Tax Asset ("DTA") follows a separate proceeding, impacts below relate specifically to the JRAP, and exclude the DTA.

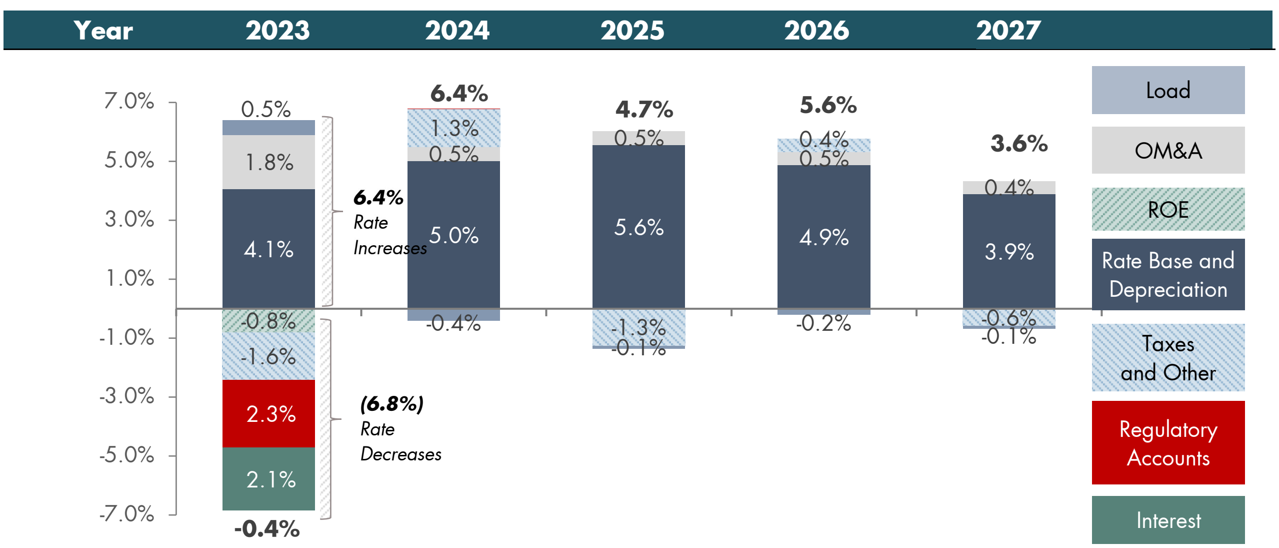
[1] Forecast filing updates are illustrative, leveraging latest forecasts for interest rates and the OEBs allowed Return on Equity ("ROE"). Consistent with prior filings, updates are intended to be made in Q4 2022, to align with the OEBs allowed ROE for 2023, and to-date actuals for issued debt in 2022, and interest rate forecasts for 2023. Also, 2021 regulatory account balances are forecast, which may be updated to 2021 audited actuals, when available.

Transmission Revenue Requirement

Initially Filed Evidence	2022[1]	2023	2024	2025	2026	2027	5 year Avg
OM&A[2]		428	437	445	454	463	
Capital Related Items[3]		1,395	1,501	1,583	1,686	1,756	
Revenue Requirement	**1,797**	**1,823**	**1,938**	**2,028**	**2,140**	**2,219**	
Other [4]	(16)	(59)	(54)	(54)	(52)	(53)	
Rates Revenue Requirement	**$1,781**	**$1,764**	**$1,884**	**$1,974**	**$2,088**	**$2,166**	
Annual Impact, excl. Load		**-0.9%**	**6.8%**	**4.8%**	**5.8%**	**3.7%**	
Estimated Load Impact		0.5%	-0.4%	-0.1%	-0.2%	-0.1%	
Annual Rate Impact		**-0.4%**	**6.4%**	**4.7%**	**5.6%**	**3.6%**	**4.0%**
~Total Bill Impact *(R1 customer - 7%)*		**-0.0%**	**0.4%**	**0.3%**	**0.4%**	**0.3%**	**0.3%**

Transmission rates revenue requirement, including load, is forecast to decrease by 0.4% in 2023, effectively holding rates flat for a typical R1 Residential Customer. Revenue requirement reductions are achieved by a combination of a lower cost of debt; lower taxes due to increased deductions for tax purposes; and the removal of 2020 Transmission foregone revenue from bills by the end of 2022. This is offset by required investments in the work program, as further described within the Investment Planning section on page 23.

Over the five-year Application, average annual rate increases for Transmission of 4.0%, which amounts to about 0.3% to a typical R1 Residential Customer's bill, reflect capital investments in the system and inflationary increases to OM&A. These estimates are net of average annual reductions of 0.1%, which have been incorporated into the rate impacts to reflect the productivity and supplemental stretch factor applied to capital, representing an upfront revenue requirement reduction to customers. The following graph outlines the year over year rate changes, by key driver:



[1] 2022 revenue requirement will be updated to reflect the latest inflation factor in Q3 2021, as part of the Tx 2022 Annual Update.
[2] 2024-27 OM&A escalated by 2.0% (2.0% 2021 OEB approved inflation less 0.0% productivity stretch).
[3] Includes ROE at 8.34%, Return on Debt at 4.04%, depreciation, income taxes, and productivity and supplemental stretch factors of 0.15%.
[4] Other includes Deferral and Variance Accounts, external revenues, export service credit, and Low Voltage Switch Gear.

The following table is intended to illustrate a sensitivity associated mainly with items outside management's control; ROE and interest rates, which will be updated in Q4 2022. In addition, forecast 2021 regulatory account balances are also reflected. Amounts are subject to change as the Company progresses through the process, and will not be reflected in initial filing evidence.

Forecasting Potential Filing Updates

Forecasting Filing Updates	2023	2024	2025	2026	2027	5 year Avg
Return on Debt (4.04%)	2	2	3	3	3	
Return on Equity (8.83%)	29	30	32	34	36	
Income Taxes from ROE change	10	11	11	12	12	
2021 Regulatory Accounts	(4)	(4)	(4)	(4)	(4)	
Forecast Changes ($)	**$37**	**$39**	**$42**	**$45**	**$47**	
Annual Rate Impact	**1.7%**	**6.4%**	**4.7%**	**5.6%**	**3.6%**	**4.4%**
Change in Rates from initial filing	+2.1%	0.0%	0.0%	0.0%	0.0%	**0.4%**

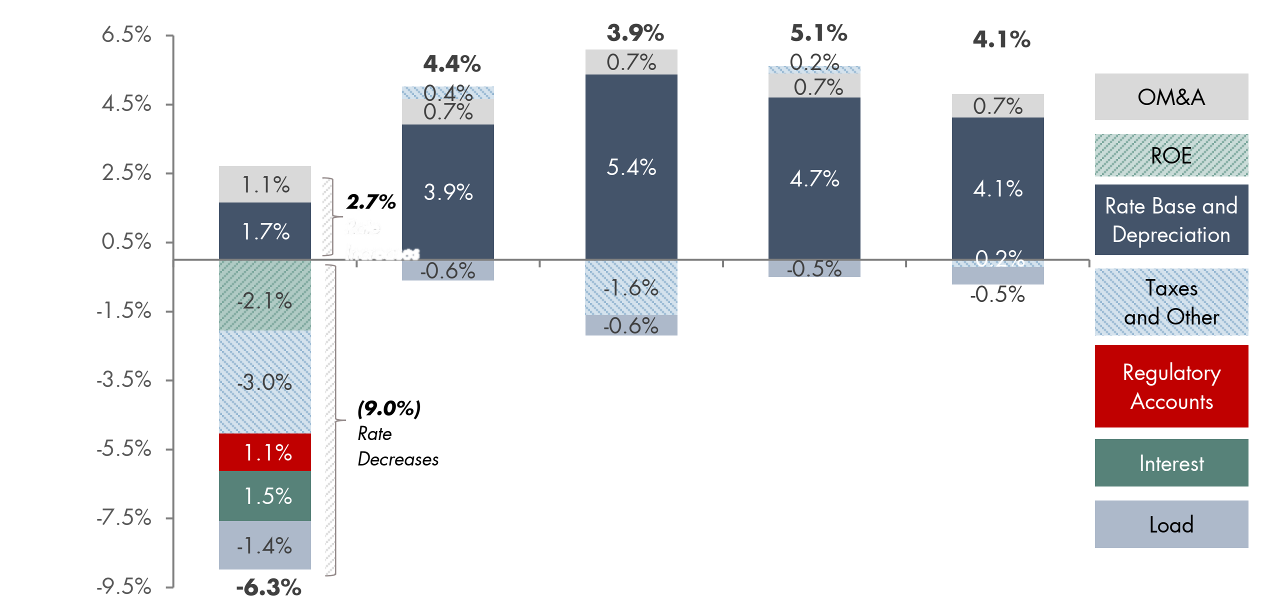
Distribution Revenue Requirement

Initially Filed Evidence	2022[1]	2023	2024	2025	2026	2027	5 year Avg
OM&A[2]		591	614	626	638	650	
Capital Related Items[3]		1,011	1,097	1,158	1,242	1,313	
Revenue Requirement	**1,662**	**1,602**	**1,711**	**1,784**	**1,880**	**1,963**	
Other [4]	(45)	(64)	(64)	(64)	(64)	(64)	
Rates Revenue Requirement	**$1,617**	**$1,538**	**$1,647**	**$1,720**	**$1,816**	**$1,899**	
Annual Impact, excl. Load		**-4.9%**	**5.0%**	**4.5%**	**5.6%**	**4.6%**	
Estimated Load Impact		-1.4%	-0.6%	-0.6%	-0.5%	-0.5%	
Annual Rate Impact		**-6.3%**	**4.4%**	**3.9%**	**5.1%**	**4.1%**	**2.2%**
~Total Bill Impact *(R1 customer - 31%)*		**-1.9%**	**1.4%**	**1.2%**	**1.6%**	**1.3%**	**0.7%**
Acquired LDCs[5]		**+$30**					

Distribution rates revenue requirement, including load, is forecast to decrease by 6.3% in 2023, reducing rates for a typical R1 Residential Customer by approximately 1.9%. This reduction is largely due to decreases in OM&A[6] through sustained productivity achievements, a lower cost of debt, and increased tax deductions largely relating to accelerated depreciation not previously planned in the prior application. This is partially offset by required capital investments, as described within the Investment Plan section. Over the CIR term, average annual rate increases of 2.2%, which amounts to about an annual 0.7% on a typical R1 Residential Customer's bill, reflect capital investments in the system and inflationary increases to OM&A. These estimates are net of average annual reductions of 0.4%, which have been incorporated into the rate impacts to reflect the

[1] 2022 revenue requirement will be updated to reflect the latest inflation factor in Q3 2021, as part of the Dx 2022 Annual Update.
[2] 2024-27 OM&A escalated by 1.9% (2.2% 2021 OEB approved inflation less 0.3% productivity stretch).
[3] Includes ROE at 8.34%, Return on Debt at 4.07%, depreciation, income taxes, and productivity and supplemental stretch factor of 0.3%+0.15% = 0.45%.
[4] Other includes Deferral and Variance Accounts and external revenues.
[5] Hydro One will integrate three previously acquired local distribution companies ("Acquired LDCs"): Norfolk, Haldimand, and Woodstock. In 2023, $30mm of revenue requirement will be integrated, however, this will be offset by increased load and customer count. Amounts for 2024-27 are fully integrated within the OM&A and capital line items, and 2024 rate impacts are relative to 2023 rates revenue requirement including the acquired LDCs.
[6] Dx OM&A reduced by $5 million relative to OEB approved, excluding $20 million of Other Post-Employment Benefit ("OPEB") non-service costs that the Company is no longer able to capitalize, consistent with applying the OEB's decision on Tx 2020-22 revenue requirement to Distribution.

productivity and supplemental stretch factors applied to capital, representing an upfront revenue requirement reduction to customers. The following graph outlines the year over year rate changes, by key driver:



The following table is intended to illustrate a sensitivity associated mainly with items outside management's control; ROE and interest rates, which will be updated in Q4 2022. Also, forecast 2021 regulatory account balances are also reflected. Amounts are subject to change as the Company progresses through the process, and will not be reflected in initial filing evidence.

Forecasting Potential Filing Updates

Forecasting Filing Updates	**2023**	**2024**	**2025**	**2026**	**2027**	**5 year Avg**
Return on Debt (4.05%)	1	1	1	1	1	
Return on Equity (8.83%)	18	19	20	22	23	
Income Taxes from ROE change	6	7	7	7	8	
2021 Regulatory Accounts	(3)	(3)	(3)	(3)	(3)	
Forecast Changes ($)	**$22**	**$24**	**$25**	**$27**	**$29**	
Estimated Rate Increase	**-4.9%**	**4.4%**	**3.9%**	**5.1%**	**4.1%**	**2.5%**
Change in Rates from initial filing	+1.4%	0.0%	0.0%	0.0%	0.0%	**0.4%**

Key CIR Framework Elements:

Consistent with the RRF, to provide customers with added benefit and protection and to incent further efficiencies, Hydro One is proposing the following features in the JRAP:

1. Productivity Factor: Hydro One will propose productivity factors of 0% for Transmission and 0.30% for Distribution, based on the results of an independent third party study as well as the industry productivity value set forth by the OEB for Ontario distributors.[1]

   Supplemental Stretch Factor: To incent further productivity, Hydro One will propose a supplemental stretch factor on capital of 0.15% for both Tx and Dx, beginning in 2024. This represents benefit to customers via upfront revenue reductions and is consistent with the OEB's recent decisions ordering an incremental capital stretch factor of 0.15%.

   The Company plans to utilize its internal Productivity Framework to achieve the productivity stretch factors as proposed under the CIR framework. The productivity factor and the supplemental stretch on capital will also be applied cumulatively year over year, similar to the cumulative nature of the progressive productivity applied in the last Tx application.

2. Earnings Sharing Mechanism: Hydro One remains committed to share with customers 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 1% in any year of the CIR term. Thus far, the ESM has benefitted Distribution customers through the sharing of $36 million, cumulatively over 2018-20.[2]

3. Capital In-service Variance Account: An asymmetrical account which refunds revenue requirement to customers if the actual in-service capital additions are lower than 98% of the OEB-approved in-service capital additions for each year of the rate period. This shows Hydro One's commitment to executing to its Plan and not over collecting in rates for work it does not achieve. Hydro One will propose a slight modification to the existing CISVA mechanism for Tx only; namely, the account will be capturing the variances on a cumulative basis over the CIR term with the ability for the Company to catch-up on any prior underspending relative to OEB approved levels and offset the impact recorded in previous years. The proposed modification is appropriate for Tx because, unlike Dx, Tx projects are large scale and multi-year in nature, to be executed over the duration of the JRAP.

4. Asset Removals Account: An asymmetric account to protect customers from Hydro One underspending on asset removals, which have varied in the past to accommodate other, primarily development, work. This account has been previously approved for Transmission for 2020-22. Hydro One is proposing to continue utilizing the account for the JRAP period for Transmission and introduce a similar account for Distribution.

[1] The Productivity Factor for each of the transmission and the distribution business is made up of two components: one which reflects the long-term industry productivity trend and one which reflects the results of total cost benchmarking research.
[2] 2018 and 2019 ESM amounts have been refunded to customers in 2021 Dx Rates. 2020 ESM is proposed to be refunded to customers as part of JRAP.

Load Forecasting

Hydro One's load and customer forecast methodology uses well established industry practices and methods, such as econometric and end-use models, Conservation and Demand Management ("CDM") inputs from the Independent Electricity System Operator ("IESO"), and customer forecast surveys. The forecast methodology has been used and approved by the OEB in Hydro One's Transmission and Distribution rate applications since 2006. Forecasts are weather-normal, meaning abnormal effects are removed so that typical weather conditions are based on a 31-year average.

The Plan uses actual 2020 amounts (peak, sales and number of customer) as the base, and includes the latest consensus forecasts for provincial/commercial/industrial gross domestic product, population, housing starts, and disposable income. The load forecast also accounts for growth related to developments in the Leamington Area of southwest Ontario.

The drivers of load growth will be offset by CDM assumptions consistent with the best available information from the IESO, as well as increased embedded generation and other drivers of load erosion.[1] While the Government of Ontario recently issued a new CDM mandate to the IESO, details of changes to the IESO plans and how those changes might impact the current transmission peak CDM assumptions are not yet available. The Industrial Conservation Initiative hiatus that the Government of Ontario implemented in 2020 in response to COVID-19 is assumed to end on May 1, 2021 consistent with the government's June 26, 2020 announcement.

Transmission Load Forecast

Peak load is projected to grow at an average annual rate of 0.3% over the Plan period. The expected growth over the Plan period is driven by higher than expected 2020 actuals, lower CDM assumptions, a higher housing starts consensus forecast, and growth related to developments in southwest Ontario.

2021-27 Weather-normal Tx Forecast (Net of CDM and Embedded Generation)

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Average Monthly Peak (MW) – OEB Approved	19,595	19,586	19,556	19,543					
Average Monthly Peak (MW) – Actual/Forecast	19,575	19,219	19,338	19,381	19,451	19,527	19,547	19,584	19,607
% change over prior year		-1.8%	+0.6%	+0.2%	+0.4%	+0.4%	+0.1%	+0.2%	+0.1%
Estimated % load impact on rates in JRAP					+0.5%[2]	-0.4%	-0.1%	-0.2%	-0.1%

The current OEB-approved forecast will be reset as part of the JRAP, which is expected to result in a 0.5% increase in rates in 2023, while increasing peak demand over the remainder of the JRAP period is expected to result in an average decrease in rates of 0.2% per year.

[1] Other factors that will negatively impact load growth include natural conservation due to customer actions (shifting and reducing energy use), natural efficiency improvements (building codes and standards), shift in industry type towards less electric intensive industries (e.g., online shopping vs brick-and-mortar shops), declining share of industrial sector in Ontario economy, and fuel switching to natural gas.

[2] Estimated load impact on rates as a result of 2023 resetting of 2022 OEB-approved forecast.

Distribution Load Forecast

Distribution load, excluding the acquired utilities, is projected to grow at an average rate of 0.3% over the Plan period, while the number of customers is expected to grow by an average of 0.7%. The expected growth over the Plan period is driven by higher than expected 2020 actuals, lower CDM assumptions, higher housing starts consensus forecast and load growth related to developments in southwest Ontario.

2021-27 Weather-normal Dx Forecast[1] (Net of Conservation and Embedded Generation)

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Sales (GWh) – OEB Approved	32,641	32,572	32,618	32,593					
Sales (GWh) – Actual/Forecast	32,990	32,691	32,797	32,912	33,021	33,136	33,246	33,352	33,457
% change over prior year		-0.9%	+0.3%	+0.4%	+0.3%	+0.3%	+0.3%	+0.3%	+0.3%
Customer # (million) - OEB Approved	1.308	1.316	1.325	1.334					
Customer # (million) – Forecast	1.317	1.323	1.333	1.343	1.353	1.363	1.373	1.382	1.391
% change over prior year		+0.5%	+0.7%	+0.7%	+0.7%	+0.7%	+0.7%	+0.7%	+0.7%
Estimated % load rate impacts on JRAP					-1.4%[2]	-0.6%	-0.6%	-0.5%	-0.5%

Due to the large share of Distribution revenue collected from fixed charges, and the fact that the number of customers is forecast to increase relative to the current OEB-approved number for 2022, resetting of the distribution forecast is expected to contribute to a decrease in rates of about 1.4% in 2023 and a further decrease of about 0.5% to 0.6% in each of the subsequent years.

Application Updates to Load Forecasts

The load forecast may be updated over the course of the JRAP proceeding. Any update will take into account the actual load data from 2021 as well as the latest economic consensus information and CDM information from the IESO available at the time.

[1] Excludes Acquired LDCs

[2] Estimated load impact on rates as a result of 2023 resetting of 2022 OEB-approved forecast.

Customer Focus

Customer Engagement

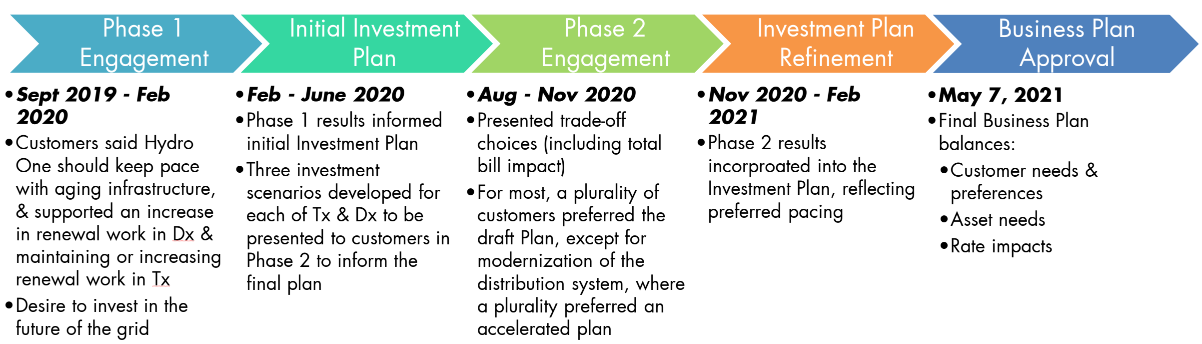
Hydro One is a customer-driven company that meets the needs and outcome preferences of its customers. To gain an understanding of what these diverse needs and preferences are, Hydro One regularly reaches out to customers in all segments and collects feedback on the service customers receive. Customer feedback guides Hydro One's business decisions on an ongoing basis.

In preparation for the JRAP, Hydro One commissioned a third-party research firm, Innovative Research Group ("Innovative") to conduct a formal customer engagement study to identify customer needs and outcome preferences and meet the requirements of the OEB's RRF. This was carried out in two phases between September 2019 and November 2020, and likely represents the most comprehensive customer outreach undertaken by any utility in Ontario to date. Business and Investment Planning, regulatory and customer engagement processes were fully integrated. Customer feedback informed the process at two crucial moments:

- Initial customer input (Phase 1 results) was presented to planners before the start of the planning process. Planners incorporated this feedback into development of the draft Investment Plan, including three scenarios developed from spring to early summer of 2020;
- Customers were invited to review the draft Investment Plan and comment on choices within the investment scenarios in late summer and fall of 2020 (Phase 2). Planners used the Phase 2 customer engagement results to revise and finalize the Plan.

This approach, together with other forms of customer engagement, allowed Hydro One to develop a final Plan for 2023-27 that is truly reflective of and responsive to customer needs.

Highlights of the process are as follows:



Phase 1 Customer Engagement – Overview and Results

Innovative surveyed a representative group of Hydro One's Dx and Tx customers through focus group sessions, telephone surveys, in-depth interviews, and an online survey using a workbook that asked customers about their needs and priorities and what trade-offs they were willing to make between rate increases and levels of investment and service outcomes. Customers across all segments prioritized reasonable rates, reliability, safety and customer service as the most important outcomes. For reliability outcomes, they prioritized reductions to the length of time to restore power after extreme weather, and fewer outages during extreme weather.

Distribution system investment trade-offs:

- The majority of customers preferred a more proactive approach to replacing aging infrastructure, when or before it starts to deteriorate. Most customers wanted investments in reliability but were divided over the level of investment, between what is necessary to maintain versus improve current levels of reliability;
- The majority of customers supported investments in hardening the system, either as part of ongoing system renewal or as proactive investments;
- Almost all customers want to help those with poor reliability, by shifting or increasing spend;
- Customers divided over spending on building capacity to enable economic growth; and
- Most customers support investments to keep the business running safely and reliably.

Transmission system investment trade-offs:

- Majority want to maintain or increase current investments to replace aging infrastructure;
- Most supported investments in a more reliable transmission system, either as part of ongoing renewal or as proactive investments; and
- The majority wanted Hydro One to make investments to improve power quality.

Three Scenarios Created Based on Phase 1 Customer Engagement Results:

- **Scenario 1: Slower Pace –** prioritizes low cost/managing rate impacts by deferring the replacement of assets in poor condition to a future rate period, and thus resulting in higher system risk and rates in the long term;
- **Scenario 2: Draft Plan[1] –** balances system and assets needs, customer preferences and impact on rates, allowing the Company to keep pace with and/or improve asset condition while managing costs and rate increases now and in the future; and
- **Scenario 3: Accelerated Pace –** responds to the needs of the system and assets, and delivers the outcomes prioritized by customers, allowing the replacement of more aging infrastructure. Costs are higher, but long term risk and rates are lower.

Phase 2 Customer Engagement

All Dx customers were invited to participate by completing an online workbook covering the Dx and Tx system. Large Tx and indirect customers served by other Dx companies had the c to provide feedback on the Tx plan. First Nation communities and the Métis Nation of Ontario were engaged through separate online workbooks and in-depth interviews, and municipalities and key stakeholders were invited to provide feedback through one-on-one interviews. In total, over 43,000 customers completed the online workbook. Customers were presented with trade-off options, representing choices Hydro One has within its Investment Plan. For each investment decision, customers were provided the option to choose between the three scenarios, previously described. **Below is a summary of the trade-offs provided to customers and the results:**

[1] Scenario 2 presented as draft Plan to show bill impact for their rate class and allow choice between slower or accelerated option for each trade-off.

Distribution and Transmission Trade-Offs and Phase 2 Customer Engagement Results

Segment	Option	Scenario 1 (Slower Pace)	Scenario 2 (Draft Plan)	Scenario 3 (Accelerated Pace)	Results
Distribution	**1. Replacing poles in poor condition**	Slow proposed pole replacement program, focusing on larger poles serving >400 customers	Replace all poles in poor condition that serve at least 100 customers	Replace all poles in poor condition that serve >30 customers	Customers support the investments included in the draft plan regarding the replacement of poles in poor condition
	2. Replacing poor condition station transformers	Reduce the pace of replacement, leading to high risk of outages and fleet deterioration	Maintain current approach; result in slight deterioration of fleet condition	Increase the planned rate of replacement, improving the overall fleet condition	Customers support the investments included in the draft plan regarding the replacement of transformer stations in poor condition
	3. Grid modernization	Deploy smart devices to improve reliability for ~200k customers	Deploy smart devices to improve reliability for ~400k customers	Deploy smart devices to improve reliability for ~600k customers	A plurality of customers would like to see an increased level of investment that goes beyond the level in the draft plan
	4. Battery Energy Storage	Deploy battery storage to improve reliability for ~500 customers	Deploy battery storage to improve reliability for ~4,000 customers	Deploy battery storage to improve reliability for ~8,000 customers	Customers clearly preferred the draft plan
	5. Facilitating Growth	Delay community growth & economic development in rural areas, impacting reliability & power quality	Allow new economic development to proceed, maintaining reliability and power quality.	Enable regional and economic development, maintaining reliability and power quality.	Customers prefer the draft plan for investments in system capacity to facilitate community and economic growth
	6. Replacing Smart Meters	Not applicable. Replacing at a slower rate could lead to higher costs	Replace meters over a 7-year period	Replace meters over a 5-year period	Residential and small business customers have preference for 7-year replacement pace of the current smart meter system, which is the pace included in the draft plan
Transmission	**7. Replacing poor condition transmission lines**	Slightly lower the current level of safety and reliability performance of transmission lines	Maintain the current level of safety and overall health of transmission lines	Moderately improve the current level of safety and overall health of transmission lines	Expressed strong support for replacement of aging and deteriorating transmission system assets to maintain the overall health of the system, consistent with the draft plan
	8. Replacing poor condition transmission stations	Replacing only the most critical infrastructure, increases performance, environmental risks and creates need for investment later on	Maintain the overall health of the transmission stations infrastructure and sustain current performance and environmental risk	Improve the overall health of the transmission stations infrastructure and reduce the risk of equipment failure	Across all, the draft plan is preferred for replacing lines in poor condition and aging and deteriorating stations. Residential & small businesses show greater interest in higher spending, beyond the draft plan

Other Customer Initiatives

Hydro One is committed to meeting customer needs and delivering consistent, high-quality service to all customers, now and into the future. This customer-driven approach allows the Company to be better positioned to improve service through everyday interactions and respond to pain points, process breakdowns, and operational changes, while strengthening its relationship with customers.

By focusing on the customer experience, Hydro One is able to provide better value and become a trusted advisor to customers for all their energy needs. The Company's focus will continue to be on finding ways to improve customer relationships by advocating for customers and helping them make informed decisions, thus achieving our strategic priority of achieving high customer satisfaction and overall impression ratings throughout the Plan.

Hydro One customers want to benefit from new technologies that provide them with convenience, help them save money, and provide reliable electricity service, while lowering their carbon footprint. In order to meet these expectations, Hydro One is actively pursuing the expansion of digital channels, and the development of new products and services. At the same time, the Company remains focused on addressing customers' needs for affordability and reliability.

In order to improve service for customers and ultimately deliver operational efficiencies, the following initiatives are currently being implemented: Call Centre Technology Replacement, outage map and notification updates, customer portal enhancements, an enhanced eBilling solution, and expansion of the Account Executive model for large and commercial & industrial customers. Hydro One's Customer Service digital strategy will be integral to achieving success. Over the Plan period, the Company will be investing in digital initiatives, including an upgrade of the Customer Information System, new mobile applications, and load disaggregation solutions.

Indigenous Relations

Hydro One aims to be a trusted partner for Indigenous communities. Investing in relationships with Indigenous Peoples and communities is the foundation for strong partnerships that support opportunities for Hydro One and the communities it serves. Hydro One owns and operates Tx assets on 26 First Nation reserves and provides Dx services to 102 First Nations communities. The Company serves just over 23,000 First Nations residential customers located on reserve lands. Hydro One engages with the Métis Nation of Ontario which supports 31 Métis Chartered Community Councils across the province. Hydro One's assets are located on First Nation reserve lands, and Indigenous traditional or treaty territories, all of which makes engagement and positive relationships with Indigenous communities foundational to Hydro One's success.

In 2021, Hydro One refined its Indigenous Relations strategy and identified four key pillars along with a number of programs and initiatives designed to support the Corporate Strategy.

The pillars of the Indigenous Relations strategy are:

- Excelling at effective, transparent engagement during projects and throughout the life of Hydro One assets;
- Working with integrity to establish corporate approaches on equity, economic benefits, and reconciliation;
- Breaking boundaries to provide innovative and lasting benefits to Indigenous communities in procurement, employment, economic benefits and investment opportunities; and
- Holding ourselves accountable by measuring progress and setting targets.

Key programs and initiatives for 2023-27 include:

- Review the Indigenous Relations Policy and implement standardized engagement tools and templates and processes to ensure consistency and transparency;
- Develop and implement an engagement plan to address section 28(2) permits under the *Indian Act* for assets on reserve land;
- Establish Indigenous procurement targets for investments included within this Plan;
- Set clear expectations with external vendors to support increased Indigenous procurement;
- Explore innovative investment and partnership opportunities in collaboration with Indigenous communities and businesses;
- Identify and address barriers to Indigenous employment and retention;
- Identify key communities for long-term relationship agreements;
- Refresh the Indigenous cultural awareness training and offer to employees and contractors;
- Implement First Nations Electricity Reliability Improvement Plan; and
- Reach Gold Level Certification from the Canadian Council for Aboriginal Business Progressive Aboriginal Relations Program.

Investment Plan

Overview

Hydro One's Investment Plan reflects its ongoing commitment to ensuring a safe, reliable, robust and sustainable Tx and Dx systems to satisfy the electricity needs of its customers and Ontario's economy. Hydro One will plan, design and build a grid for the future by focusing on prudent investments in Ontario's electricity grid. Targeted investments will maintain system performance, meet regulatory and customer service requirements, and help customers make informed decisions.

Hydro One is sensitive to the impacts on its customers as well as the end-use customers of other Local Distribution Company's ("LDCs"), and has taken steps to ensure that its approach to identify and pace investments is in alignment with principles of the OEB's RRF and supports the Company's strategic objectives by:

- Ensuring that the Investment Plan considers customer needs and preferences identified in customer engagement as previously described, and that is consistent with the feedback obtained from various other customer consultations undertaken by the Company;
- Ensuring continued focus on the importance of the health and safety of employees, contractors, customers, and the public;
- Delivering performance and service outcomes based on the expectations and priorities of customers and stakeholders;
- Actively driving cost reductions and productivity savings to help offset rate impacts;
- Working with customers, transmitters, distributors and key stakeholders to ensure regional infrastructure issues and requirements are addressed in an integrated manner;
- Continuing the performance management system to provide accountability for outcomes;
- Embedding innovation and new technologies to address challenges and opportunities; and
- Complying with all relevant legislative and regulatory requirements.

The Company achieves this through proactive engagement and working closely with customers, including First Nation and Métis communities. Hydro One strives to ensure that it can deliver a level of service that is responsive to customer needs and preferences, as well as operational needs, while also mitigating rate impacts. As part of continuous improvement, innovation will be embraced to address the need to build a progressive, modern and flexible system and infrastructure for the future. The Company is committed to finding better ways to provide affordable and reliable transmission and distribution of power.

Key drivers of the Investment Plan include:

- The needs and preferences of transmission and distribution customers;
- The need to sustain poor condition transmission and distribution assets and infrastructure to provide outcomes consistent with customer expectations and as the steward of infrastructure, vital to the economy of Ontario;

- Responding to customer and provincial requirements to expand the grid to meet increasing demand, including those identified through the integrated regional planning process;
- The need to integrate distributed energy resources;
- Statutory and regulatory requirements, including those which provide access to and/or modifications of the transmission and distribution system to enable customer connections or accommodate third party relocations;
- The need to transform the current system into a modern, flexible grid for the future; and
- The need to advance the Government of Ontario's energy policy objectives.

Section 1: Asset Management and Investment Planning Process

Section 1.1: The Asset Management Process

Asset management is the "systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, their associated performance, risks, and expenditures over their life cycles for the purpose of achieving its organizational strategic plan." [1] Hydro One's asset management process is consistent with industry practices and this framework is an integrated, life-cycle approach for the effective management of infrastructure. Hydro One primarily uses two concurrent approaches when considering investments:

1. A life cycle management approach which considers and balances asset performance, costs and associated risks during the asset's service life (the asset management process); and
2. A forward-looking approach with respect to anticipated system needs and developments, typically looking ahead five to ten years into the future (the Investment Planning process).

Hydro One identifies and prioritizes investments based upon its asset management process. This process employs the Company's expertise and experience to monitor its assets, identify and define asset needs, and determine the appropriate timing for investment and maintenance activities. During this process, the specific, unique characteristics of transmission and distribution investments are captured through the development of candidate investments, for example:

- **Distribution investments are:**
  - Characterized by near-term, high-volume activities undertaken on a provincial basis ("program based"); and
  - Responsive to external/demand driven factors like responding to storms, customer connections, and accommodating third party joint use and relocation requests.
- **Transmission investments are:**
  - Typically large, multi-year discrete projects; and
  - Developed through the identification of needs through an integrated and coordinated process, which may involve the IESO, connected customers including industrials and LDCs, and/or generators.

[1] British Standards Institution, Publically Available Specification 55, 2011

Section 1.2: The System Planning Process

The Investment Planning process provides a consistent understanding of risks to enable Hydro One to select the best value investments and service for its customers. This process is a structured three-stage process that allows for the consistent assessment and prioritization of candidate investments based on the level of risk mitigated and the cost and value delivered toward achieving business objectives. The long-term objective of this process is to achieve Hydro One's mission, vision and values through the renewal and modernization of existing infrastructure and the development of the grid for the future. This is completed through prudent and responsible planning to renew poor conditioned assets to mitigate risk, at a pace that mitigates critical risks first while managing residual system risks in order to maintain safe and reliable operations. **The three stages of the Process are as follows:**

Strategy and Context	Asset Management	Investment Planning
•Strategic Priorities •RRF Outcomes •Customer Engagement	•Current State Assessment •Investment Candidate Development	•Risk Management •Prioritization and Optimizaiton •Customer Engagement •Plan Development •Plan Approval and Delivery

Strategy and Context: Within the context of asset condition, customer priorities, and customer and system load profiles, long-term system needs are identified and a strategy is developed. This considers actions required to renew, maintain, and where appropriate, improve the system.

Asset Management: Through this process, a current state assessment occurs, where multidimensional needs, including specific asset condition and system requirements, are evaluated, leading to the formulation of potential options and development of investment candidates.

Investment Planning: Based on the candidate investments, Hydro One uses a comprehensive and robust process to identify, prioritize and optimize investments. This approach allows Hydro One to manage costs, address asset and system operational risks, address customer needs and preferences, and mitigate rate impacts. Risk taxonomies covering safety, reliability and environment consequences guide candidate investment assessments. These assessments underpin the prioritization and optimization of candidates to produce a draft portfolio of investments.

Following the development of the draft portfolio, extensive engagement was undertaken, soliciting feedback from internal business units related to costs and execution considerations, as well as through Phase 2 of Customer Engagement and stakeholder sessions.

Changes that arise during the rate period are addressed through Hydro One's Redirection Committee, which allows for prudent and timely readjustment to be made to the Plan.

Section 2: Customer Engagement and Final Plan Selection

The draft Investment Plan was presented to customers in Phase 2, as previously described on page 17. Planners reviewed the results of Phase 2 to produce a final Investment Plan. Relative to the draft, the final Investment Plan incorporates two key changes to reflect clear customer feedback:

- The pacing of distribution investments to improve system reliability through grid modernization was increased to reflect customer preferences; and
- The replacement rate of distribution station transformers, transmission station transformers and transmission lines to improve reliability was increased slightly.

The final Investment Plan also incorporates key findings and recommendations from third party expert studies. Relative to the draft plan, the following revisions were made in this regard:

- A need to reinvest in fleet vehicles to manage lifecycle requirements;
- Cost effective approaches to distribution wood poles asset management; and
- An updated utilization rate for shared assets in the transmission and distribution segments.

Final updates have also incorporated latest load forecasts, which reflect the need and timing for customer connections and system reinforcements required to enable local and regional growth.

Final Investment Plan[1,2]

$mm	2021	2022	2023	2024	2025	2026	2027
Transmission Capital	1,141	1,180	1,434	1,464	1,450	1,462	1,448
Transmission OM&A	314	316	333				
Distribution Capital	714	665	991	1,009	1,106	1,055	1,057
Distribution OM&A	512	512	520				
Acquired LDCs Capital	13	13	14	19	15	16	14
Acquired LDCs OM&A	11	12	11				

Section 3: Transmission System Plan

Hydro One has developed a comprehensive, integrated Transmission System Plan ("TSP") for the 5-year period from 2023-27, to maintain, renew, and enhance transmission infrastructure. The TSP is a product of the Investment Planning process, which is previously described on page 23.

The 2023-27 TSP was developed through the integrated customer engagement exercise and was prepared in accordance with the OEB's filing requirements and RRF. Investments through

[1] Transmission and Distribution OM&A shown for 2023 only as Revenue requirement in the first year, 2023, is determined using a forward test year cost of service approach. Revenue requirement in the following four years is equal to the prior year inflated by a custom RCI for the given year. Please refer to Appendix A for a continuity of Total Transmission and Distribution OM&A.
[2] Represents work program costs only.

2023-27 are required to address poor condition, deteriorated infrastructure, including lines and stations.

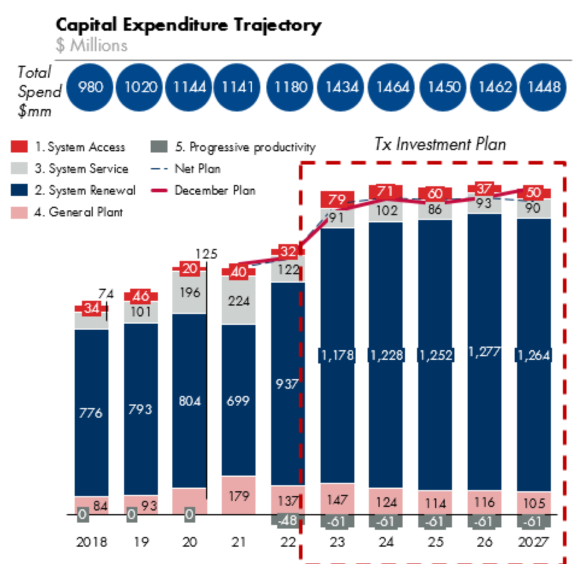
The TSP is targeting to **maintain first quartile system reliability performance throughout the Plan**, reflecting Hydro One's priority of providing safe and reliable power to customers. Hydro One still faces challenges in the years ahead to address the needs of an aging and deteriorating transmission system, while maintaining and continuously improving in the areas valued most by its customers and stakeholders, including safety, reliability, outage restoration and power quality. Hydro One's TSP continues to strike a balance between:

1. Asset related needs of the system arising from condition-based risks and environmental and regulatory compliance requirements;
2. Customer needs and preferences relating to reliability and risk;
3. Regional infrastructure needs to address system constraints, enable new load growth; facilitate access and new connections to the transmission system; and
4. Customer rates.

To inform the TSP, Hydro One assesses and tests the condition of critical assets. Verified asset condition underpins all asset replacement decisions. The Company continually improves this process through the assessment of asset performance (including failure investigations), improved data governance processes, conducting industry engagement and seeking input from third party experts. Transmission stations and lines risk assessments are informed by many factors including condition assessments from analytic methods, like transformer oil analysis, conductor torsion and ductility testing, maintenance history, loading, ongoing inspection and monitoring information, reliability performance, obsolescence and net present value analysis.

Section 3.1: 2020–22 Transmission Capital:

The Company is delivering on its OEB approved 2020-22 plan, however is faced with pressure from externally driven investment requirements. Hydro One is balancing this externally driven work and the need to address with system needs affecting customers. The capital plan is expected to exceed the OEB approved capital and in-service addition envelope by $68 million and $83 million, respectively. This cost variance is driven by the increased scope and complexity of Lakeshore area investments, required to enable further growth in the Leamington area. Efforts have been made to accommodate this variance through the deferral of some renewal work; however, the replacement of poor condition assets is necessary to sustain operational performance, safeguard reliability to downstream customers and need to manage to OEB-approved envelopes at the category level.



Section 3.2: 2023-27 Transmission Capital

Over 2023-27, spending of $7.3 billion is required to address poor condition assets required to maintain Tx reliability performance and mitigate asset and operational risks, respond to statutory and regulatory requirements to expand and enhance the electricity grid to meet increasing demand and provide access to and/or modifications of the system to enable customer connections.

Capital expenditures increase by 22% from 2022 to 2023 due to increased system renewal needs. Asset condition assessments showed a significant portion of transmission system assets have deteriorated to the point where they pose material risks to safety, reliability, minimizing environmental impacts and meeting customer needs.

Despite increasing capital expenditures over 2018-20, the rate of increase has generally managed to only maintain or prevent significant deterioration of the asset fleet, as much of the infrastructure was installed in the 1950s and 1960s. Historically, the pace of infrastructure renewal has been impacted by growth and system development, resulting in the deferral of renewal investments. **Not proceeding with the proposed investments** will defer replacement of poor condition assets thereby increasing the number of deteriorated assets that will remain in-service, increasing the likelihood of failures, and presenting risks to the safe and reliable operation of the system.

The table below summarizes the capital Investment Plan, by the OEB- categories:

Summary of Transmission Capital Plan[1]

$mm	2021	2022	2023	2024	2025	2026	2027
System Access	40	32	79	71	60	37	50
System Service	224	122	91	102	86	93	90
System Renewal	699	937	1,178	1,228	1,252	1,277	1,264
General Plant	179	137	147	124	114	116	105
Progressive Productivity[2]	-	(48)	(61)	(61)	(61)	(61)	(61)
Total	**$1,141**	**$1,180**	**$1,434**	**$1,464**	**$1,450**	**$1,462**	**$1,448**

In developing the TSP, Hydro One considered the context of the broader Ontario power system. With a changing generation outlook and planned nuclear refurbishments, Hydro One expects greater outage scheduling constraints in the future that will make work more difficult to complete. In determining the timing and pacing of investments, Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage times to minimize impacts on customers and stakeholders. This is further discussed in the work execution section on page 42.

[1] Certain investments related to physical and cyber security have historically been characterized as System Renewal; however, as part of the JRAP, these costs will be characterized as General Plant.

[2] Progressive productivity represents commitments made during the Tx 2020-22 application that are sustained through JRAP. Incremental productivity reductions for JRAP are applied to revenue requirement via productivity stretch factors, as described in the Application Framework & Rate Change section.

Safety, environment, and reliability risk mitigation are at the core of the TSP. Hydro One strives to be an industry leader in safety and environment for its employees, contractors, and customers by achieving and maintaining "World Class" safety performance. This Plan will maintain top tier reliability performance for customers and incorporates their input and priorities. Each investment is assessed on a clear and consistent scale based on three risk factors: safety, environment, and reliability risk mitigation. Each investment has the potential to address more than one risk factor. Reliability is a focus of this Plan through the replacement/refurbishment of poor condition assets or system enhancements. Investments are planned to mitigate safety risk by replacing deteriorated assets in publicly accessible areas or replacing equipment with known risks to employees, such as equipment with insufficient arc-flash protection. Further, investments will mitigate environmental risks, including the installation/refurbishment of oil spill containment facilities and the elimination of polychlorinated biphenyls ("PCBs") from the system by replacing contaminated equipment with more than 50 parts per million by 2025, in compliance with federal environmental legislation.

The main conditions driving the investments in each OEB category are set out below.

System Service and System Access

The TSP includes approximately $0.8 billion to meet statutory and regulatory obligations to provide transmission access and additional capacity for new customer connections and to implement bulk and regional development plans, developed jointly with large industrial customers, distributors and the IESO. The TSP will result in the following system additions:

- New transformer stations including Leamington/Lakeshore Phases 4 - 6, and connection of new customer-owned stations including Copeland Phase 2;
- Major projects including new and expanded Tx facilities required to support the significant load growth in the Leamington Area and upgrades/expansion in urban areas such as Ottawa and the Greater Toronto area; and
- Reinforcements to interties, strengthening the resilience of the bulk transmission system.

Some of the large system development projects have a high level of uncertainty driven by external factors, or may be subject to future partnerships; thus, those projects have been excluded from the TSP and will be the subject of a future accounting order application to the OEB.

Hydro One will also seek approval for a symmetrical externally driven work variance account to record the variance between the revenue requirement impacts of System Access in-service additions arising from third party initiated work and the revenue requirement impacts of actual System Access in-service additions initiated by third parties during the rate period. A similar account will be requested for the Distribution business. Such an account will enable Hydro One to continue to prioritize reinvestment in existing infrastructure, and not redirect to accommodate externally driven considerations.

System Renewal

Hydro One's proposed 2023-27 TSP reflects the need for continued investments in stations and lines renewal driven by asset condition. Verified asset condition underpins all asset replacement decisions. A significant portion of the assets have deteriorated to the point where investment is required. Based on the latest assessments, 16% of transformers, 11% of circuit breakers and 14% of overhead conductors are in a degraded state. Relative to the 2020-22 application, investments have not kept pace to materially improve the overall condition of these key assets. Consequently, investments to replace these poor condition assets are required to maintain reliability and meet safety and environmental sustainability requirements.

The Plan includes $4.2 billion to address deteriorating Tx station assets, including transformers, circuit breakers, and protection, control and telecom equipment. These replacements will manage the fleet condition of major station assets. Key stations renewal investments include:

- Addressing poor and deteriorated condition transformers, replacing and reconfiguring approximately 3% of the transformer fleet per year; and
- Replacing obsolete and poor performing air-blast circuit breakers and associated high pressure air systems located at bulk electrical stations which are crucial for the reliable operation of the system. The air-blast circuit breakers are approximately ten times more costly to maintain and four times less reliable than the SF6 circuit breakers.

The TSP includes an increased emphasis on lines sustainment related investments at a cost of $2.0 billion. The investment will refurbish and replace poor condition transmission lines, insulators, wood poles, and extend the useful life of steel structures through tower coating. Although increased relative to historical years, the pace of lines refurbishment will be at a reduced pace, following the OEB Decision in the 2020-22 application.

As the system ages and equipment deteriorates, risk is managed by prioritizing line refurbishment investments identified through detailed asset condition assessments. Significant portions of assets have deteriorated to the point where investment is required to maintain reliability and meet safety and environmental sustainability requirements, including 14% of overhead conductors verified as poor condition. Lines sustainment program highlights are reflected below:

- Address verified poor condition conductors, replacing and refurbishing approximately 1% of the overhead line fleet per year;
- Replace defective insulators on over 19,900 critical circuit structures;
- Replace almost 5,400 poor condition wood poles; and
- Coat over 2,500 steel structures to extend their useful life.

General Plant

General Plant investments provide centralized operations enablement functions, supporting operations through common facilities, transport and work equipment, and information and operating technology. Focus areas include Operations and Service Centres located throughout the province, which serve Hydro One's transmission and distribution businesses and provide base locations for field crews and the materials, tools and equipment relied upon to deliver maintenance and restoration services in a safe, timely, effective and efficient manner. Further, the General Plant investments also include technology and communications sustainment and enhancements, which facilitate process reengineering, improve situational awareness in the field, enable business efficiency, and address new regulations for cyber security and physical security requirements. For more information on General Plant, please refer to Shared Services and Information Solutions within the Work Execution section of the Plan.

Section 3.3: Transmission In-Service Additions

In-service additions are developed by combining the best forecast available for all investments within the transmission portfolio that have assets planned for capitalization during the test years. Projects in execution encounter many challenges during the execution stage such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities and emergent investments. These project challenges may result in changes to the timing of in-service. However, the Company expects to be able to manage within +/- 2%.

Summary of Transmission In-Service Additions by OEB Category[1]

$mm	2021	2022	2023	2024	2025	2026	2027
System Access	15	44	73	49	61	63	36
System Service	181	387	59	21	164	72	99
System Renewal	654	895	1,165	1,187	1,431	1,107	1,419
General Plant	156	80	126	137	116	100	106
Progressive Placeholder	-	(24)	(55)	(61)	(61)	(61)	(61)
Total	**$1,006**	**$1,382**	**$1,368**	**$1,332**	**$1,710**	**$1,280**	**$1,600**

System renewal in-service capital additions will increase through 2027, driven by an increased focus on addressing poor condition stations and lines assets. General plant investments are expected to see a relative and absolute increase in in-service additions in 2024 and 2025 as a result of new operations centres and maintenance garages in central Ontario.

System Service in-service additions will vary from year-to-year, driven in large part due to the timing and need identified through integrated planning processes and required solutions, while System Access investments are largely driven by customer and third party timing.

Currently, Hydro One has an established CISVA for Transmission. The accounts track the difference in revenue requirement associated with the variance between actual in-service additions and OEB-approved and is asymmetrical to the benefit of customers. For JRAP, a slight modification to the existing CISVA mechanism will be proposed. The account will capture variances on a cumulative basis over the CIR term with the ability to catch up on any prior underspending relative to OEB approved and unwind the impact recorded in previous years. This modification is significant for Transmission in light of the multi-year, large scale of projects, coupled with the duration of the JRAP relative to when the Plan was derived. Under this proposal, Transmission will remain accountable to capital commitments, however it will be assessed over the full Application period.

[1] Certain investments related to physical and cyber security have historically been characterized as System Renewal; however, as part of the JRAP, these costs will be characterized as General Plant.

Section 3.4: Transmission Work Program OM&A

The Plan is designed to maintain and improve reliability, maintain asset condition, and comply with regulatory and legal requirements. The Plan appropriately balances customer rate impacts with the requirements of the system. The table below reflects the summary OM&A to 2023, with 2024-27 to be managed in accordance with CIR inflationary factor:

Summary of Work Program Transmission OM&A Plan

$mm	2019	2020	2021	2022	2023
Other Sustainment	25	28	32	35	39
Vegetation Management	32	33	32	32	33
Lines Sustainment	24	22	20	20	22
Stations Sustainment	128	119	122	122	127
Development	3	5	6	7	7
Operating and Customer	21	21	23	21	23
Common	77	72	79	78	82
Total	**$308**	**$299**	**$314**	**$316**	**$333**

The Plan reflects $333 million in 2023, a 5% increase relative to forecast 2022 levels amidst a growing asset base and increasing compliance costs arising from evolving regulatory standards, such as the North American Electric Reliability Corporation's ("NERC") Critical Infrastructure Protection and Cyber Security reliability standards. The increase supports:

- Increase line and stations maintenance to levels comparable to historic levels, to identify and address power equipment defects, assess future replacement candidates and repair ancillary grounding systems to address safety risks;
- Continue to invest in application management, licences and cloud hosting to enable improved business outcomes through information and operating technology; and
- Further system hardening to reflecting the cyber threat landscape and ensure compliance.

If OM&A funding falls below the proposed 2023 level, Hydro One would complete less maintenance work on assets that need to be examined and repaired, resulting in a build-up of deferred work, and carry out fewer condition assessments resulting in:

- Less condition data to underpin investment decisions;
- Reduced ability to identify high priority deficiencies, which would then go undetected until the associated equipment fails and causes unplanned outages; and
- An inability to invest in security systems jeopardizing the Company's security posture and posing risks to the safe and reliable operation of the system.

Stations OM&A

Stations maintenance programs will address corrective, preventative and refurbishment work, as well as key compliance requirements related to NERC standards and PCBs remediation. Hydro One continues to deploy new tools and processes to improve operational performance. Through condition assessment techniques, such as transformer dissolved gas analysis, Hydro One has been able to reduce some programs, relative to historic levels. Identified refurbishment work, such as air-blast circuit breaker auxiliary component remediation, will be prioritized, as these components are system critical and interface with key generators such as nuclear and hydro generating stations.

Corrective maintenance addresses unplanned failures along with any defects identified through preventative maintenance. These maintenance programs are funded at historic levels. Incremental corrective or demand failures will be mitigated through work prioritization and redirection in year.

Addressing PCBs contaminated equipment to comply with federal environmental legislation by Environment Canada's December 31, 2025 deadline is a large OM&A program within the Stations category. Hydro One will continue to complete this compliance work including to test, retro-fill and dispose of PCBs and PCBs contaminated equipment.

Lines OM&A

Hydro One's Transmission Lines maintenance program focuses on vegetation management and right-of-way maintenance, overhead lines maintenance and underground cable maintenance. The Plan has prioritized funding to address transmission line asset condition assessments, right-of-way brush control, and right-of-way line clearing programs.

The overhead lines maintenance program will fund the condition assessment of lines assets. Overhead inspections are performed to identify transmission line components with major defects. Identified defects and assets that fail will be replaced on a prioritized basis through the overhead lines demand corrective program.

Hydro One's vegetation maintenance program addresses 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.

Underground cable maintenance 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 underground cables are located in major urban centers, including downtown in Toronto, Ottawa and Hamilton. The Plan focuses on performing regulatory cable locates and high priority preventive and corrective maintenance on underground cables.

Section 4: Distribution System Plan

Hydro One has developed a comprehensive, integrated Distribution System Plan ("DSP") for 2023-27, to maintain, renew, and enhance distribution infrastructure. The DSP is a product of the Investment Planning process, which is previously described on page 23.

The landscape of the distribution business is changing, with opportunities that will both disrupt and enhance through innovation. Today, significant quantities of assets are in poor condition or not built to modern industry standards, with many assets in need of replacement. System renewal presents a unique opportunity to modernize the grid by replacing deteriorated assets with assets incorporating new technologies consistent with industry trends and system demands.

The 2023-27 DSP will accelerate the path towards a modernized grid of the future which, together with innovative work practices, will allow Hydro One to serve customers in a more nimble and reliable manner. Over the Plan, feeders will be modernized with the installation of approximately 1,200 remote operable switches and re-closers and the installation of approximately 5,000 communicating faulted circuit indicators. Customers have indicated that cost effectiveness, reliability and customer choice are amongst their key priorities. Notable initiatives that will deliver or enable outcomes in alignment with customer needs and preferences include:

- System Renewal and modernizing Worst Performing Feeders: Hydro One is pursuing System Renewal investments which address asset needs and provide operational efficiencies (e.g. by bundling work where feasible to minimize the need for additional work mobilization and outages); balancing asset needs, resource availability and impact to customers. The volumes prioritized for replacement have been selected based on their impact to reliability and safety risks. A revised approach to station refurbishments provides a cost effective approach to mitigate reliability risk. Continued focus on the Worst Performing Feeders and the deployment of modern automation technologies is expected to improve reliability for some customers served by these lines by an average of 40%; and
- Incorporating innovations into the Plan: Hydro One is pursuing a number of innovative approaches to completing work including increasing the use of data collected from smart devices to reduce operational costs and leveraging new technologies including battery energy storage to improve reliability.

Hydro One's DSP strikes a balance between:

1. Asset related needs of the system arising from poor asset condition (including associated reliability, safety and environmental risks), customer service obligations and regulatory compliance requirements;
2. Customer needs and preferences relating to performance and risk;
3. Regional infrastructure needs to address system constraints, enable new load growth, and facilitate new connections to the distribution system; and
4. Impact on customer rates.

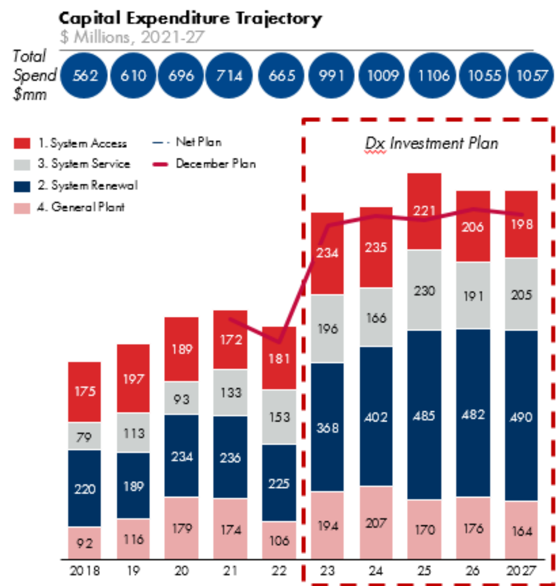
Section 4.1: 2018–22 Distribution Capital

The Company is delivering on its OEB approved 2018-22 plan, however is faced with pressure from external factors and externally driven investment requirements, including significant System Access requests. Hydro One is balancing this externally driven work and the need to address with system needs affecting customers. As a result, the 2018-22 capital plan is expected to exceed the OEB approved capital envelope by $187 million, and exceed the approved in-service additions by $61 million, respectively.

This overage reflects significantly higher volumes of system access investments required to meet legal and regulatory requirements to connect new customers and respond to third party joint use and relocation requests, system renewal investments for storm restoration, system service investments to enable significant system expansion in the Leamington area of southwestern Ontario, and general plant investments to enable the business. Hydro One has made efforts to accommodate this variance through the deferral of some renewal and system service work; however, the replacement of poor condition assets is necessary to sustain operational performance, ensure reliable service to customers and need to manage to OEB category level approvals envelopes. The overage has been partially mitigated through the select reprioritization and redirection of planned system service and system renewal investments.

Section 4.2: 2023-27 Distribution Capital

Over the Plan period, Hydro One plans to invest $5.2 billion of capital in the distribution system, representing an average growth of 5.9% from 2020. The forecast is $991 million for 2023 and increases to $1,057 million in 2027.



Over the 2021-23 period, distribution capital expenditures decrease in 2022, followed by an increase in 2023. The reduction in 2022 is driven by two significant, one-time general plant investments which are forecast to be complete in 2021: the new Integrated System Operations Centre, and the Dx Design Optimization and Transformation project, which will modernize the approach to delivering accurate and consistent design and cost estimates for customers.

Distribution capital is forecast to increase by approximately 49% from 2022 to 2023, to enable Hydro One to address asset and system risks, meet its service obligations and compliance requirements, and achieve outcomes that are consistent with customer needs and preferences. The year-over-year change is driven by an enhanced focus on addressing poor condition and deteriorating infrastructure, including increased replacement of wood poles, station transformers and the legacy Advanced Metering Infrastructure ("AMI"). System enhancements will also be pursued to improve system reliability through grid modernization and tie-lines, and the deployment of energy storage systems to improve reliability for customers experiencing exceptionally poor reliability. Without this increased level of investment, poor condition assets will present an increased risk of failure, and Hydro One will not be able to achieve the performance improvements and outcomes that were supported by customers in its Customer Engagement exercise.

Increased investment levels are expected in 2023-27 to address poor condition, deteriorated infrastructure, including poles, metering and stations, and development projects to increase system capacity to address load growth as well as investments targeting reliability improvements through grid modernization and energy storage.

An overview of investments by OEB investment categories is set out below:

Summary of Distribution Capital Plan by OEB Category[1]

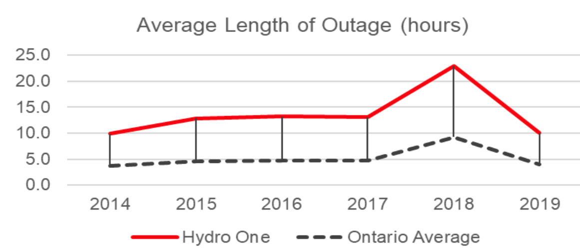
$mm	2021	2022	2023	2024	2025	2026	2027
System Access	172	181	234	234	221	206	198
System Service	133	153	196	166	230	191	205
System Renewal	236	225	368	402	485	482	490
General Plant	174	106	194	207	170	176	164
Total	**$714**	**$665**	**$991**	**$1,009**	**$1,106**	**$1,055**	**$1,057**

System Access and System Service

System Access investments are driven by mandatory obligations, including those relating to new load and generation connections, line relocations, service upgrades and wholesale metering.

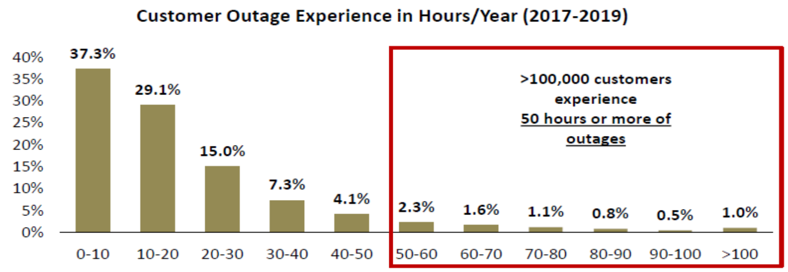
Hydro One is required to plan and build its system to provide a safe and reliable supply of power to all its customers. System Service investments accommodate load growth that would otherwise limit the ability of the system to provide reliable service, including the construction of additional facilities to enable the connection of new customers (e.g., as a result of the unprecedented growth of the greenhouse industry in southwestern Ontario).

Targeted investments are planned to improve system and customer-specific reliability. Hydro One tracks both the average number and duration of power outages per customer. On average, between 2014 and 2019, the typical Hydro One customer experienced 1.5 more outages per year compared to the Ontario average. When it comes to total time spent without electricity each year, the typical Hydro One customer, since 2014, has been without power for over 10 hours each year.



Outage experiences vary across Hydro One's service territory, and some customers experience more frequent or longer outages than others. While some Hydro One customers did not experience any outages between 2017 and 2019, over 100,000 customers were without power for more than 50 hours per year. Some communities experienced up to 150 hours of outages.

[1] Excludes Acquired LDCs.



Technology has advanced in recent years, offering solutions that would allow Hydro One to detect, repair and restore power more quickly than in the past through the use of remotely operable devices and communicating faulted circuit indicators. The deployment of these devices will reduce the length of time customers are without power and will improve reliability for poorly performing supply feeders. In addition, targeted investments in energy storage are expected to improve customer specific reliability, for those customers experiencing significant outages.

Over the course of the Plan, significant investments are being made to accommodate the anticipated increase in regional load demand. For example, in the Leamington Area where there is significant growth in the greenhouse sector, over $170 million of net investments will be made to construct feeders for new transformer stations and provide contributions for upstream facilities over the 2023-27 period, in addition to over $200 million anticipated to be invested through 2022.

Similar to transmission, Hydro One will seek approval for a symmetrical externally driven work variance account to record the variance between the revenue requirement impacts of System Access in-service additions arising from third party initiated work and the revenue requirement impacts of actual System Access in-service additions initiated by third parties during the rate period. Such an account will enable Hydro One to continue to prioritize reinvestment in existing infrastructure, and not redirect to accommodate externally driven considerations.

System Renewal

System renewal investments primarily consist of storm damage restoration, pole replacements, the replacement of the advance metering infrastructure (smart meters), and distribution lines and distribution station refurbishments. Storm damage restoration funding is forecast based on historical spend to account for yearly fluctuations. Currently approximately 77,000 wood poles have been assessed to be in poor condition, a figure that is expected to grow significantly by the end of 2027 without intervention of a targeted pole replacement program. Over 20% of station transformers have been assessed as in poor condition. Hydro One regularly assesses the condition of transformers, with a goal of replacing deteriorated assets before failure.

In the near-term, the pole replacement program is expected to experience fluctuations in volume of units due to competing needs for capital funding among various projects and mandatory priorities, including system growth and new connections. As a result, pole replacement rates will be at a lower pace than previously proposed to the OEB for 2021 and 2022. Over the Plan period, approximately 51,000 wood poles in poor condition will be replaced through the pole replacement program. To supplement traditional replacements, a new program for pole refurbishment (mechanical and chemical treatment) has been introduced to manage the pole population cost effectively, including the refurbishment of approximately 14,000 poles over the 2023-27 period. The station refurbishment program is expected to increase to reflect the significant quantities of assets (particularly, station transformers) that are in poor condition and require replacement.

Hydro One's legacy AMI 1.0 system will begin to reach the end of its 15-year service life in 2022. This service life has been attested to by the vendor and is supported by a number of studies including the OEB commissioned Asset Depreciation Study, which found that the appropriate useful life for smart meters was in the range of 5-15 years. As the AMI 1.0 system ages, meter failures (primarily the loss of the ability of the meter to communicate) are steadily increasing (doubling between 2017 and 2020), and meters are showing conditions of disrepair. Based on independent Accelerated Life Testing results, meter failure projections show at least 45% of the meter population failing by 2027. Without intervention, high meter failure rates pose significant and critical risks to Hydro One's operations and pose regulatory risks. Consequently, Hydro One has initiated a competitive Request-For-Proposals ("RFP") process for a new AMI 2.0 system.

The AMI 2.0 program is a multi-year investment given its scope, spanning the 2021-28 period. Upon the completion of the RFP process, the program will begin in late 2021 through 2023 with operational preparedness planning; designing and installing a new Head-End-System; and conducting a small scale pilot. Mass meter and network replacement is planned over a 5-year period, beginning in 2024, scaling up for a sustained period from 2025-27, before ramping down to completion by 2028. Although customers preferred a longer 7-year mass replacement pacing approach that pushed some costs out of the JRAP period, the 5-year pacing approach results in an estimated $48M in program cost savings without a material increase in program execution risk; an additional projected $20M in savings of sustainment costs by replacing failing AMI 1.0 meters more quickly; and helps mitigate billing reliability risks of accelerating AMI 1.0 meter failures.

General Plant

General Plant investments provide centralized operations enablement functions, supporting operations through common facilities, transport and work equipment and information and operating technology. Focus areas include Operations and Service Centres located throughout the province, which serve Hydro One's transmission and distribution businesses and provide base locations for field crews and the materials, tools and equipment they rely upon to provide maintenance and restoration services in a safe, timely, effective and efficient manner. Further, General Plant investments also include technology and communications sustainment and enhancements, which facilitate process reengineering, improve situational awareness in the field and enable business efficiency. For more information on General Plant, please refer to the Shared Services and Information Solutions within the Work Execution section of the Plan.

Section 4.3: Distribution In-Service Additions

Hydro One's in-service addition plan is developed by combining the best forecast available for all investments within the distribution portfolio that have assets planned for capitalization during the test years. Projects in execution encounter many challenges during the execution phase such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities and emergent investments. These project challenges may result in changes to the timing of in-service additions. However, the Company expects to be able to manage within +/- 2%.

Summary of Distribution In-Service Additions by OEB Category

$mm	2021	2022	2023	2024	2025	2026	2027
System Access	183	181	234	236	221	206	198
System Service	71	138	227	146	249	200	194
System Renewal	249	225	349	419	495	468	498
General Plant	198	112	148	211	220	172	202
Total	**$700**	**$656**	**$958**	**$1,012**	**$1,186**	**$1,046**	**$1,092**

System renewal in-service capital additions will increase through 2027, driven by an increased focus on addressing poor condition stations and lines assets. General plant investments are expected to see a relative increase in in-service additions in 2024 and 2025 as a result of new distribution and operations centres and maintenance garages in central Ontario.

System Service in-service additions will vary from year-to-year, driven in large part due to the timing and need identified through integrated planning processes and required solutions, while System Access investments are largely driven by customer and third party timing.

Currently, Hydro One has an established CISVA for Distribution (2018-22 test years). The accounts track the difference in revenue requirement associated with the variance between actual in-service additions and OEB-approved in-service additions for that year. The account is asymmetrical in nature to the benefit of the customers. For the JRAP test period, Hydro One will propose to continue with a similar CISVA for Distribution for 2023-27.

Section 4.4: Distribution Work Program OM&A

Distribution OM&A reflects the implementation of the OEB's Decision in the 2018-22 rate application, and is forecast to remain flat over the 2020-23 period. The OM&A programs are summarized as follows.

Summary of Work Program Distribution OM&A Plan[1]

$mm	2019	2020	2021	2022	2023
Other Sustainment	156	160	138	140	138
Vegetation Management	161	139	140	140	137
Lines Sustainment	12	14	8	8	12
Stations Sustainment	17	19	18	18	19
Development	10	8	14	12	13
Operating and Customer	83	85	92	91	93
Common	101	96	104	103	108
Total	**$541**	**$520**	**$512**	**$512**	**$520**

Distribution OM&A expenditures reflect constraint, efficiency and cost control, reflecting values significantly below the previously filed application, and which are expected to increase at a rate less than inflation, while delivering outcomes valued by customers. This approach to cost control provides customers with an overall benefit through the 2023 rebasing.

The most significant expenditure in Dx OM&A is vegetation management, which addresses vegetation along Hydro One's approximately 100,000 kilometres of right of way, mitigating one of the most significant drivers of reliability performance on the distribution system. Other significant investment areas include customer service, which includes the Customer Contact Centre to address customer concerns, meter reading, and meter network and billing operations to deliver timely and accurate bills.

Other sustainment costs include responding to trouble calls and restoring power, performing cable locates, and testing equipment for high concentrations of PCBs, which is expected to wind down as Environment Canada's 2025 deadline approaches.

Section 4.5: Acquired LDCs

Hydro One has operationally integrated the acquired utilities. Over the 2015-20 period, operational efficiencies have been realized through the reduction of duplicative back-office and overhead support services and systems, by leveraging Hydro One's existing common corporate functions and services model. The incremental costs for these utilities, which include OM&A expenses for activities such as vegetation management and line maintenance, and capital investments such as pole replacements, are planned through Hydro One's asset management framework, applying asset lifecycle principles. Work is undertaken by an integrated workforce to address asset, system and customer needs in a cost effective manner. The incremental costs are displayed separately, as identified previously, in part to address concerns raised regarding the longer term cost allocation driver and regulatory reporting requirements, and deliver on specific commitments to maintain or improve select service quality measures.

[1] Figures exclude Acquired LDCs.

Work Execution

Hydro One is committed to the execution of its large and complex portfolio of investments. As previously described, the Company strives to achieve within +/- 2% of the in-service commitments filed with the OEB, while also looking for opportunities to efficiently execute OM&A and Capital work plans, without sacrificing safety. This work execution is managed and tracked in several organizations, as follows:

- **Transmission & Stations:** Accountable for the safe and cost-effective maintenance and construction of transmission lines, and transmission and distribution stations, including all associated program and project management functions for the portfolio;
- **Distribution Lines and Forestry:** Accountable for the safe and cost-effective maintenance and construction of distribution lines, and vegetation management of transmission and distribution right of ways, including program management functions for the portfolio;
- **System Operations:** Control the transmission and distribution systems, maintain system standards and provides dispatch services, manage the AMI network;
- **Shared Services:** Supply Chain for procurement of materials and services, Fleet Services to maintain and provide equipment and transportation to Operations, and Facilities Management to maintain warehouses, service centres, and buildings, Real Estate Management, and Helicopter Services to provide aviation services to Operations; and
- **Information Solutions:** Maintains and provides information technology ("IT") enabled services to the business.

The following section outlines specific execution strategies with respect to the above noted organizations, which will demonstrate, in combination with the Company's historical achievement of work plans, that the Plan as presented can be executed safely and efficiently. Key aspects associated with the execution strategy are set out below.

The Company plans to execute its Transmission and Distribution investment portfolios by enabling workforce flexibility and driving efficient planning through productivity initiatives across the organizations. The Transmission & Stations organization ("T&S") will leverage external contractors/partners and increase outsourcing capabilities to deliver the incremental work program. The Distribution Lines and Forestry organization will adopt a contracting/Purchased Service Agreement strategy for execution of incremental work to address the fluctuating and seasonal nature of Distribution's work program. The Shared Services organization will support Tx and Dx work programs by continuously improving its supply chain process, utilizing fleet efficiently and ensuring all facility-related work are completed on time and within budget. Information Solutions Division ("ISD") will enable the execution of work programs by providing digital solutions through modernized information and power systems technology.

Transmission & Stations

Transmission & Stations is accountable for the execution of the majority of Tx OM&A and Capital work programs in a safe and efficient manner. The organization also delivers the Dx OM&A and Capital work programs as they relate to Dx Stations, and complements the Dx workforce in the accomplishment of specific Dx Lines capital projects. The unit is comprised of engineering, work management, and work execution functions.

Engineering is accountable for the design and support for transmission station and line assets. Design activities are executed with both internal resources and pre-qualified engineering firms to manage fluctuations in the work program. Engineering is committed to improving safety by design by building stronger partnerships with the executing LoB; and is a partner in the continuous improvement initiatives that will result in productivity savings.

Work management groups are accountable for program and project management services for all T&S work. In addition to end-to-end coordination of investments, they are accountable for estimating, scheduling, project controls, contract management functions and outage planning on the power system. The entire organization must work closely and collaboratively with other operations groups like Planning, Supply Chain, Environment, Indigenous Relations, Community Relations, Real Estate and System Operations to execute a large and growing work program with a strong commitment to continuous improvement, safety and overall execution efficiency.

Work execution functions are cross-functional and comprised of several different labour groups across the Power Workers' Union ("PWU"), Society of United Professionals ("Society"), and Construction Trades. Together these work groups are focused on the safe and efficient execution of the capital portfolio as well as the largest segment of the Tx OM&A work program. Hydro One has demonstrated the ability to successfully execute large capital work plans and reduce the variability of capital expenditures and in-service additions using a skilled internal workforce and qualified third-party contractors. Historically, the execution of construction projects was delivered with approximately 90% direct hire casual trades (retained directly by Hydro One, and subject to terms of existing collective agreements and Electrical Power Systems Construction Association ("EPSCA") agreements), and 10% through external construction partners. In 2020, this started to shift with a greater portion (approaching 20%) of the capital projects being delivered with external construction partners. With the growing Tx Capital work program over the Plan period, the portion of the work program executed through external construction partners will increase, while the regular and casual workforces remain relatively stable to safely and efficiently build capacity and maintain a diverse and flexible workforce. This shift will provide T&S with the flexibility to respond to increasing demand and urgency for load growth projects while maintaining the knowledge and capability to successfully execute complex refurbishment projects.

Hydro One is committed to the execution of its complex portfolio of capital work on the transmission system. With a Tx capital project execution process that benchmarks strongly relative to its peers, Hydro One is confident in its ability to execute the work programs in 2023-27. Through the Plan, Hydro One aims to achieve annual in-service additions within +/- 2% of the commitment to be made to the OEB. To ensure optimal execution, Hydro One has developed an execution strategy to focus internal resources on complex brownfield station refurbishment projects (i.e. Air Blast Circuit Breakers) that are highly outage dependant and typically connected to large generation facilities (Ontario Power Generation Inc. and Bruce Power Limited Partnership), outage dependent repeatable program work, and customer connections. Hydro One utilizes external contractors through various execution delivery models where the scope of work can be clearly defined and complexities can be managed or, where required, specialty construction skills are not available within Hydro One. These types of projects include high voltage underground cable work, greenfield transmission stations or lines projects, relay buildings and unique projects where the involvement of original equipment manufacturers is required (i.e. High Voltage Gas Insulated Switchgear) or telecom projects.

The workforce executes preventive and corrective maintenance on the Tx system to ensure continued reliability of service for customers, and is accountable for real-time response to power system events as the maintenance authority. The workforce is engaged in commissioning and acceptance testing for projects, providing a final quality and function check in the asset deployment process. The work is typically performed by regular and casual status Hydro One employees.

Of primary importance is the continued effort to improve safety performance, including the actions identified by the Safety Improvement Team and the ongoing roll-out of the Human Success program, as described in the Health and Safety section on page 7, and advancements in managerial and supervisor competencies in relation to evolving the safety-first culture.

T&S has recently undertaken a number of initiatives to increase the effectiveness and efficiency of its capital work program delivery. The Capital Delivery Model Enhancement will clarify decision authorities, strengthen the authority of project managers operating in a matrix organization and improve the predictability of project success through an improved project change management process. Productivity efforts will be focused on the field execution costs through various Field-force Enablement initiatives starting with Stations Construction and expanding to include Transmission Lines in 2022 and beyond. Technology improvements will be key enablers in successfully delivering on the growing work program. T&S has plans to implement new scheduling tools for work execution functions as well as improved reporting and analysis tools that will assist project managers in aligning disparate data sources to see all aspects of their projects, e.g. providing effective and centralized visibility to cost, schedule, and contract commitments.

Hydro One has demonstrated that it can execute a large and growing capital work program while maintaining the needed flexibility to accommodate required adjustments in its capital work plan due to changing priorities, project challenges and emergent investments. With a number of improvement initiatives underway and a strong work execution strategy, Hydro One feels confident in its ability to successfully achieve a growing capital work plan.

Distribution Lines and Forestry

The Distribution Lines and Forestry organizations are accountable for designing, estimating, scheduling, and executing all work related to Lines and Forestry in a safe, efficient and productive manner. The organization is accountable to deliver a complex work program, which consists of investments driven by customer demand and compliance obligations, investments to sustain existing assets, and investments that modernize the system to improve reliability. A large proportion of the work program consists of high volume work activities completed annually. The investments that make up the work program are either planned or demand-driven. Planned investments include pole and cross-arm replacements, line patrols, defect corrections and vegetation management on both transmission and distribution circuits. Other planned investments include projects that deliver new or modified system facilities to accommodate upgrades for load growth, asset life cycle optimization and reliability improvements. Demand-driven investments include new connections, service upgrades, disconnects/reconnects, trouble/storm response and joint use and line relocations.

The proportion of demand investments that make up the overall work program has been increasing year over year. The timing and volume of demand work can vary relative to historical results, requiring reprioritization of other work programs. As a result, Hydro One Distribution is continually seeking opportunities to become more efficient and flexible, to effectively respond to demand impacts while still accomplishing its planned work programs.

Distribution has developed resource strategies, productivity and continuous improvement initiatives to enable Hydro One to execute the large and complex portfolio of investments on the distribution system, and to achieving distribution reliability targets.

The resource strategy for Distribution Lines and Forestry is designed to ensure safe and efficient delivery of the Distribution work program, while maintaining commitments to Hydro One customers. A work-based approach to staffing is utilized, whereby Hydro One sources staff according to work programs rather than planning the work around the number of internal resources available. To address the fluctuating and seasonal nature of the Distribution work program, the organization maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, casual, hiring hall, temporary, and contract staff for both Lines and Forestry. Included in the resource strategy is a suite of robust apprenticeship and training programs with the guidance of experienced tradespersons and technicians. Forestry resources are also shared amongst Distribution and Transmission portfolios, which require the organization's execution strategies to be integrated to enable workforce flexibility and drive efficient planning and execution of all vegetation programs.

Workforce flexibility is a fundamental aspect of Distribution's resource model, while maintaining alignment within the parameters of collective agreements. Hydro One utilizes pre-qualified vendors when a specific skillset required on a non-regular basis is not available internally or when an influx of work creates a short-term need for additional support. This is necessary to ensure the efficient execution of the work program and address ongoing variation in requirements for specific skills. As a result, Hydro One has continued to focus on its outsourcing options through the use of Purchased Services Agreements and RFPs. By stipulating the business requirements and necessary skillset, Hydro One maintains control of the scope of work while driving price transparency and efficiency among proponents.

Hydro One has also focused on developing relationships with First Nations communities by offering vegetation management opportunities, through fixed price contracts, within right of way corridors located on reserve lands.

Hydro One Distribution has recently undertaken a number of initiatives to increase the effectiveness of capital and OM&A work programs. For example, to drive efficiencies within the Trouble Call program, the Company implemented an initiative to reduce the cost per trouble call by altering shift schedules and dispatching a single person for certain types of trouble calls, without increasing trouble call recordable safety incidents or materially impact customer satisfaction and restoration times. Design time and number of site visits associated with pole replacement, new connection and service upgrades are also expected to be reduced as a result of implementing upgrades to the design and estimation tool.

The Distribution Lines and Forestry organization strives to improve its work planning and scheduling practices, streamline accountabilities and enhance processes. The use of a new Work Manager System, along with other technology advancements, has helped in the planning, tracking, and executing of work programs. Leveraging the use of geographic information systems, grid modernization as well as exploring the use of advanced technology such as remote sensing to assess vegetation growth, provides the business with further opportunities for continuous improvement.

With these improvement initiatives and a flexible resource strategy, Hydro One is confident in its ability to achieve a growing work program as outlined in the Plan.

System Operations

System Operations carries out the real time control and operation of the transmission and distribution systems, maintains system standards and provides dispatch services, and manages the AMI network. Over the JRAP period, capital investments for System Operations include AMI 2.0 and Common Operating Technology Infrastructure. The Network Management System, Outage Response Management System and Distribution Management System are also critical investments required to maintain the viability of Operations applications.

For the reasons discussed in the Distribution Capital section, the Hydro One legacy AMI 1.0 system will reach the end of its service life in 2022 and will be replaced by the AMI 2.0 system over the 2023-27 rate period and beyond.

The Common Operating Technology Infrastructure is for the upkeep and timely replacement of computer, storage, network and other core Operating IT Infrastructure necessary for controlling the bulk electric system and guiding Tx & Dx Grid operations from the Integrated System Operations Centre and Backup Ontario Grid Control Centre. The assets covered include modular components such as VMware, storage area network switches and storage devices, with fixed lifecycle and vendor support consistent with industry practices. Failure of any of these components can cause system impacts including disruption to business functions, and an inability to maintain safe grid operations. These align with the Corporate Strategy to Plan, Design, and Build a Grid for the Future.

The Network Management System, Distribution Management System and Outage Response Management System are necessary for the operation of and planning for work on the transmission and distribution system under normal grid and emergency conditions. Investments in these systems are required to support proactive and cost effective outage management planning and scheduling on essential grid components and equipment to support outage response management capabilities and enhanced monitoring and control on the Tx and Dx Systems. These investments align with the Corporate Strategy to Plan, Design, and Build a Grid for the Future.

Shared Services

The Shared Services organization delivers shared services that enable the business to achieve operational excellence and supports Tx and Dx work programs through a number of functions, including Supply Chain, Fleet Services, Facilities & Real Estate and Helicopter Services. Shared Services supports the Strategic Priority to be the safest and most efficient utility by driving efficient work program delivery and is aligned with the OEB's RRF Operational Effectiveness outcome through its continuous improvement and productivity initiatives.

Supply Chain

Supply Chain is responsible for all Source to Pay operations. Activities include category management and strategic sourcing, contract management, warehousing and logistics, inventory management, supplier performance/relationship management, supplier qualification and inspection services, warranty and claims management, purchasing services, and accounts payable.

The function is undergoing a transformation that will focus on driving continuous improvement in people, processes and technology while improving the service and value it delivers. The people transformation will see continued improvement in the area of Category Management, with targeted investment in staff competencies and talent management. All currently outsourced Supply Chain functions will also be insourced as of November 1, 2021, including: Accounts Payable, Construction Order Desk, Contract Administration and Purchasing Services. By insourcing these functions, Supply Chain staff will be led by a single management team, with complete alignment of goals and priorities, which will enable the successful execution of the many strategic projects planned in the coming years. Supply Chain will also be conducting a review of its operating model, to optimize its use of staff through improved end to end processes, and by leveraging its current suite of industry leading technology.

With the capital work program increases planned over 2023-27, Hydro One recognizes that this will increase the overall demand and support required from suppliers. The aforementioned transformation initiatives will enable Supply Chain to be dynamic and responsive to business units' needs, by ensuring the timely delivery of materials and services at the right place and price.

Working with Indigenous Communities

Supply Chain actively seeks out new Indigenous business partners through community outreach programs and industry associations such as Nation Talk and the Canadian Council of Aboriginal Businesses. Once businesses are identified, an Indigenous Procurement Champion within Supply Chain acts as a single point of contact to help them navigate the procurement process and promote their business with internal stakeholders. Supply Chain has also updated its sourcing policies and guidelines to make it easier to direct award work to qualified Indigenous businesses when pricing is already competitive or work is adjacent to a First Nation's reserve. In addition, Real Estate Services, working with Hydro One Indigenous Relations and Legal, is a key contributor in negotiations with 24 First Nations within the province to establish and maintain permits following the federal Indian Act or First Nation Land Management Act for Permitting and licencing of Transmission Assets on First Nations Reserves and Community lands. Hydro One's commitment to continuously improve its relations with Indigenous stakeholders has resulted in the Company being awarded a Silver certification with the Canadian Council for Aboriginal Business for its Progressive Aboriginal Relations program.

Fleet Services

Fleet Services provides centralized and turnkey services including equipment acquisition, maintenance, administration, vehicle replacement and final disposition of transport and work equipment, while supporting various Lines of business ("LoBs") and complying with safety laws and regulations.

Fleet Services takes a systematic approach to fleet replacement, ensuring that staff have the equipment they need to execute work programs. This process begins by identifying the end-of-life equipment that needs to be replaced each year and then prioritizing available funding based on organizational needs as well as mechanical and financial criteria. The timeline for procuring light-duty vehicles, from the date of purchase to the date of in-service, is approximately six months. The equivalent timeline for heavy-duty vehicles is approximately six months for "off-the-lot" vehicles and 10 to 14 months for customized vehicles, which applies to the majority of Hydro One's heavy-duty fleet. The delivery of the equipment does not mark the end of Fleet Services' controls on the delivery process. Before Hydro One accepts any piece of delivered equipment, fleet inspectors confirm that each vehicle or equipment meets Hydro One's specifications. Fleet Services continuously monitors equipment performance to ensure that it represents best value for customers, meets the need of the work programs and substantiates the fleet renewal investment being proposed.

As the Tx and Dx work programs have been increasing, the demand for transport and work equipment has also increased. The options to meet this growing demand include increased utilization of existing equipment, redistribution of low-utilized equipment and/or arranging for rentals. Fleet benchmarking studies indicated, among other things: (1) Hydro One's average ownership, operating and support cost per vehicle is less than its peers, and (2) a shorter lifecycle for vehicles is recommended based on the independent expert's lifecycle policy analysis. The need to manage fleet assets based on a prudent lifecycle strategy, which serves to minimize fleet lifecycle costs and equipment downtime over the longer term, resulted in an increase to the proposed capital expenditures for Hydro One's fleet over the 2023-27 period.

In an effort to reduce Hydro One's carbon footprint, The Company's commercial fleet is beginning the gradual transition to low or zero emission technology, increasing the rate of electric vehicles from an estimate 5% of the renewal forecast in 2020 to 45% by 2030. The pacing reflects the balance required to transition to a green fleet, while also minimizing potential business and operational risks associated with rapid changes in technology and infrastructure.

Facilities & Real Estate

Facilities & Real Estate manages sites and buildings that support administration and service functions across various LoBs and the assets connecting to the power system. Facilities oversees the provision, management and maintenance of work locations, including head office, administrative and service centres, garages, warehouses and Tx station buildings. Real Estate Services manages the land rights portfolio.

To effectively evaluate Hydro One's portfolio and understand the condition of its assets, preventative maintenance and building condition assessments are conducted by BGIS, a Canadian firm specializing in facilities management and project delivery services. BGIS identifies assets in need of repair and/or replacement prior to failure and submits a work proposal outlining the scope of the projects along with cost estimates. All facility capital projects are centrally tracked, regularly reviewed and assessed by Hydro One. Factors such as health, safety, environment, site security, and LoB needs are considered when prioritizing projects. Facilities & Real Estate prioritizes work that addresses high criticality components or high impact risks in the short term and plans future investments in a way that limits rate impact while addressing longer-term risks or requirements.

Real Estate Services ensures that all rights related to Hydro One-owned Tx lands, easement and statutory right properties are maintained and acquired to ensure the safe and reliable operation of the system. In addition, Real Estate Services oversees the management of rights associated with Dx lands, stations and other property. It also provides specialized real estate service activities which include management of property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services. Real Estate Services administers the Provincial Secondary Land Use Program on behalf of the Ministry of Government and Consumer Services and Infrastructure Ontario, and Hydro One's program, which permits compatible uses on the transmission corridor lands for a fee. Together these programs generate on average $25-$29 million per year in revenue for Hydro One.

The Facilities & Real Estate capital work execution strategy is focused on ensuring that facility-related work (i.e. renovations, upgrades, and new builds/greenfield development) are completed on time, on budget, and in accordance with Hydro One's required standards and procedures. For sustainment work, Hydro One works collaboratively with BGIS to arrange for consulting and construction work through a competitive bidding process. For new-build projects, Hydro One may consider executing internally if it is more cost effective or better meets the required schedule.

In 2020, as a result of the COVID-19 pandemic, Hydro assembled an internal working team to explore the opportunities to adopt a hybrid workforce model where employees can work from both the office and home. This team's work is underway and will include an assessment of Hydro One's future facilities and corporate real estate needs.

Helicopter Services

Helicopter Services is an operating unit within Shared Services and is a turnkey operation providing airborne transportation support and oversight of third party contracted vendors to Hydro One's workforce. The group is responsible for the lifecycle management of the Company's helicopter fleet, including obtaining initial capital approvals, budgeting, equipment acquisitions, maintenance and repairs. Helicopter Services aims to provide safe, reliable and efficient helicopter support to various LoBs, including to support line patrols, transport workers and materials, complete pole setting, and outage/storm response.

The Helicopter Services' work plan over the 2023-27 period will involve the purchase of new helicopters, potential base location re-alignment and the development of a remotely piloted aircraft systems program to drive efficiencies with data gathering for asset management and increasing the margins of safety with helicopter operations.

A key focus of Hydro One's capital acquisition strategy with respect to helicopters is to preserve and develop Hydro One's capability to respond to customer demand and asset failure. The execution strategy is flexible and scalable. For longer, heavier poles, Hydro One has the ability to hire larger helicopters on a short-term basis, allowing it to expand and contract its fleet as necessary. For summer demand peaks, Hydro One will triage the work required and determine whether less complex work may be performed by third-party vendors providing helicopter services.

Information Solutions

The mandate of Information Solutions is to enable Hydro One's strategic objectives through digital solutions, protect through increased cyber, physical, and personnel security maturity, and operate efficiently through modernized information and power systems technology.

Information Solutions is transitioning to a new operating model that involves in-sourcing several IT functions that were previously outsourced through Inergi Limited Partnership ("Inergi"), resulting in greater in-house subject-matter expertise and immediate costs savings beginning in 2021, as reflected in this Plan. This translates to delivering more capital work using internal resources through the 2021-27 period compared to previous periods. With an expanded work program over the Plan, Information Solutions is being organized into a pod model, where self-organized teams of workers ("pods") each provides "cradle-to-grave" support for specific technology solutions for a particular LoB. This new operating model will be crucial in Hydro One's efforts to continuously improve capital work execution by enabling the delivery of IT solutions more quickly, efficiently, and with higher standards of technical support. Information Solutions has maintained a relationship with Capgemini Canada Inc. after the in-sourcing of its Inergi employees, and with a renegotiated contract continues to optimize the use of their services for both project and sustainment work. Where value remains to outsource specific technology and security functions to other third party vendors and contractors, Information Solutions seeks to optimize these agreements via competitive bid process, utilizing contractors to supplement specialized skill sets that may not be available internally.

Information Solutions' plan for the JRAP period drive three key outcomes, which are aligned with Hydro One's continuous effort to achieve the outcomes under the OEB's RRF, mainly by focusing on customer needs and preferences and improving operational effectiveness:

1. Enable the business: leverage technology, reduce costs and drive business process excellence:
   - Focus on end-to-end integrated asset and work planning to enable the Grid of the Future;
   - Drive efficiencies and improved analytics in the business through implementation of robotics and machine learning, reporting analytics and business process optimization;
   - SAP Foundation investment aimed at a managed transition to the new S/4HANA platform;
   - Optimize the way that Hydro One plans, schedules and dispatches work in the field through enhancing the existing mobility tools over the Plan period;
   - Update the way field data is captured and stored electronically for more efficient use for planning, scheduling, and execution in the field through geographic information system upgrades;
   - Enhance Human Resources capabilities through innovative and modern technology solutions;
   - Realise improvements in customer service and satisfaction with modernized Computer Telephone Integration systems, and then extending the solution to Field Business Centers and other LoBs to facilitate seamless customer transaction handoffs;
   - Enable increased throughput in transmission construction project delivery via investments in technology implementations and enhancements in scheduling, work accomplishments, cost and contract management solutions; and
   - Enhance customer-focused systems to support interaction on mobile and web self-service.

Key customer focus investments highlighted above are required to increase Hydro One's capabilities, better align with industry-leading customer service, and drive overall customer satisfaction. These customer-focused investments also make it easier for customers to do business with Hydro One and make informed decisions, in alignment with the Corporate Strategy of advocating for our customers. Information Solutions investments in technology are also a required enabler to improve operational effectiveness. Investments identified around improved field data capture and analytics and updates for planning and scheduling capabilities will help maintain and improve overall system reliability by better identifying the most critical work, and controlling costs by more effectively planning and scheduling that work.

2. Optimizing Information Technology & Operating Technology Operations and Project Delivery by (i) investing in enterprise class technology and (ii) driving cost reduction through IT productivity savings (including by renegotiating and reducing contractor and professional services rates). Additional optimization opportunities will be sought through:

- Restructured outsourcing model: in-sourcing key roles at reduced cost when compared to outsourcing, modernized IT operations driving operational efficiency; and
- Transition to a new target operating model in Information Solutions that leverages pods to better support business needs and increase efficiency. This will follow industry best practices and communication techniques to minimize disruption.

These opportunities identified help drive cost reduction while maintaining / improving effectiveness, which is a key outcome in both the Corporate Strategy and the OEB's RRF.

3. Building strong enterprise-level security governance to consistently protect assets, effectively manage security risk, and ensure a safe and secure work environment, while meeting regulatory obligations and aligning to support and enable business objectives and the Corporate Strategy. This will be achieved by making prudent investments to ensure the grid's readiness to defend against current and future cyber threats by increasing monitoring and protections.

   - In-sourcing physical and cybersecurity operations for better business alignment and cross collaboration with Hydro One's power system and Telecom operations;
   - Developing a best-in-class Identity and Access Management capability;
   - Modernizing infrastructure-wide physical security monitoring and response capabilities while maturing Hydro One's personnel and physical security program; and
   - Establishing industry-leading partnerships to leverage Government of Canada cybersecurity capabilities to defend Hydro One's business and infrastructure.

Enhancing Hydro One's security posture through cyber and physical investments will improve our grid resiliency and sustainability to quickly restore from events. These investments will assist Hydro One in monitoring and protecting from cyber threats through near-real time situational awareness and visibility into vulnerabilities. These investments are also aligned with the OEB's RRF by driving outcomes towards increased system reliability, through protection against threats, which protect the system performance and data.

At any given time, Information Solutions is executing a large number of critical IT enabled projects, and therefore a number of risk mitigation and governance measures have been implemented ensuring successful delivery and business objectives are achieved, including:

- Strong project delivery governance through the use of a Stage Gate Delivery Model that incorporates an Executive Steering Committee and Project Management Oversight & Leadership Team ("PMOLT") to review project status prior to moving to next project phase;
- Monthly progress reporting of critical technology transformation projects to the executive leadership team;
- Governance meetings with LoB stakeholders to review projects and validate ISD priorities; and
- Program Managers across ISD portfolio participate in a Priority Project PMOLT to ensure cross-portfolio awareness and de-risk project/resource contention.

Hydro One is continuously evaluating the levels of IT investments. The Information Solutions team collaborates closely with other LoBs to identify strategic, multi-year technological capability requirements to achieve business outcomes and address capability gaps. Similar or overlapping needs from different LoBs are grouped and all investments are examined in terms of optimizing lifecycle management costs to maximize use of existing systems and line up system end of life with future/planned enhancements. Investment Plans are refreshed annually to ensure that business outcomes are being achieved that align with the Corporate Strategy, making adjustments due to changes within the business or industry environment. All investments go through the Investment Planning process, which incorporates assessment of risk mitigation, the benefit to Hydro One customers, and enabling the Corporate Strategy objectives, as discussed on page 5.

In conjunction with addressing business capability gaps with technology, Information Solutions annually evaluates existing hardware and software assets to determine their health and capabilities. If the assets are approaching their end of life (e.g., technological obsolescence or beyond vendor support) and can be linked to a specific improvement initiative, the upgrade and improvement of the asset will be incorporated into that initiative. The prioritization of these enabling investments is primarily based on the value added (including from the lens of cyber security) relative to the costs. Through this approach, the Company aims to deliver on the initiatives that provide the best value to the business, factoring in risk mitigation, value to customers, and enablement of strategic objectives.

Environment

Hydro One is committed to delivering electricity to customers and managing operations in an environmentally responsible and sustainable manner, and strives to understand environmental impacts of operations. Work is delivered in a way that reduces negative impacts while embracing opportunities to enhance the environment. The Company's Environmental strategy focuses on identifying the highest environmental risks in alignment with priorities in the Corporate Strategy. Risks are identified and evaluated through practices common to internationally certified Health, Safety and Environmental Managed Systems ("HSEMS"). For the environment portion of the HSEMS, Hydro One is aligned with the International Organization for Standardization 14001:2015 standard. The Environmental strategy includes five strategic initiatives:

1. Execute supporting the grid of the future, including both mitigation measures to reduce greenhouse gas emissions and adaptation initiatives to enhance the resiliency of the grid;
2. Continue to support HSEMS programs addressing key environmental risks such as contaminated lands management, resource management, and environmental stewardship;
3. Integrate environmental management and compliance into operational activities;
4. Be a trusted environmental partner through growing relationships and delivering on commitments for external government, industry, communities, and Indigenous partners; and
5. Ensure training, monitoring and continual improvement of environmental requirements.

Key investments include the Climate Change strategy which is aligned with the Climate Change and Extreme Weather component identified in Hydro One's annual Sustainability Report and HSEMS Programs with program funding related to:

- Contaminated Lands: Includes investments in the Land Assessment and Remediation and Spill Response Programs. Targets include remediation of high and medium risk Tx and Dx sites with historical contamination. Targets are set each year based on funding and the relative cost of each remediation and related works. The spill response program targets a recovery of 90% of liquid spills which reduces impacts to the environment;
- Resource Management: Includes funding for air, water and waste management as well as chemical management including PCBs. Related funding ensures compliance to provincial approvals for drainage systems, proper waste handling and disposal and phase out of PCB-containing equipment by 2025 in accordance with federal requirements. Sampling and analysis are included in this funding; and
- Environmental Stewardship: Includes environmental planning, community engagement and Indigenous relations, biodiversity enhancement, land management, and heritage resources. Funding ensures compliance with regulatory requirements related to environmental and cultural heritage legislation. It allows Hydro One to protect natural habitats, species at risk, heritage and archaeological resources, air, soil and water quality and enhance the natural environment through biodiversity initiatives. The goal is to ensure Environmental Protection Plans are prepared for all capital projects that could have impacts to the environment or require environmental permits or approvals.

FTE Planning & Compensation Cost Mitigation

To deliver on the Transmission and Distribution Business Plan and to meet the associated strategic and business objectives through to the end of the Plan, Hydro One must have the capacity to execute its planned work. For the 2023-27 Plan period, the primary focus is on meeting the increasing workload demands associated with the growing capital work while managing long-term compensation costs, optimizing efficiency, and ensuring customer-focused outcomes.

93% of Hydro One's total workforce (both regular and casual) is unionized; compensation costs are directly impacted by existing agreements and the collective bargaining process. Feedback from the OEB related to compensation costs informs Hydro One's collective bargaining strategies and the Company will continue to pursue cost-saving opportunities at each round of bargaining with its respective union partners during the rate period.

Overall compensation costs are also determined by the size of the workforce relative to its output, and the type of labour retained (regular, temporary, or casual). Hydro One will leverage the workforce flexibility it achieved in previous rounds of collective bargaining to meet incremental increases in planned work without significantly impacting compensation costs relative to the scale of the work portfolios in Distribution and Transmission. Hydro One's ability to efficiently assign work, and ability to and contract out work (per the terms of its existing collective agreements with the Power Workers Union and the Society of United Professionals), will allow Hydro One to deliver its 2023-27 Plan without significantly increasing the size of its regular workforce, thus effectively managing compensation costs.

Planning Process

In determining the most appropriate resourcing option, Hydro One evaluates the nature of each line of business's operations and primary function(s) vis-à-vis: long/short term labour costs; safety and security considerations; duration and scope of work; service level standards; applicable collective agreement provisions; as well as need for innovation/efficiency. A holistic assessment of these factors results in a spectrum of workforce resourcing strategies that align to the needs and constraints of each line of business ("LoB"). For Transmission and Distribution, work execution strategy depends on increased casual labour and targeted plans for using external resources (contracting out) to optimize flexibility and cost-effectiveness.

Full Time Equivalent Planning Assumptions

Type	Representation	2021	2022	2023	2024	2025	2026	2027
Regular	MGT/Non-Represented	724	761	765	760	760	763	763
	Society	1,675	1,771	1,781	1,783	1,791	1,817	1,841
	PWU	3,704	3,748	3,738	3,720	3,718	3,703	3,674
	Total Regular	**6,103**	**6,280**	**6,284**	**6,263**	**6,269**	**6,283**	**6,278**
Casual	PWU Hiring Hall	1,329	1,300	1,388	1,397	1,480	1,602	1,524
	CUSW	938	911	912	912	912	912	912
	EPSCA	198	192	192	192	192	192	192
	LIUNA	247	237	237	237	237	237	237
	Total Casual	**2,712**	**2,640**	**2,729**	**2,738**	**2,821**	**2,943**	**2,865**
	Total Non-Regular	175	158	159	158	157	157	157
Total		**8,990**	**9,078**	**9,172**	**9,159**	**9,247**	**9,383**	**9,300**

- The table above provides a summary of full-time equivalent ("FTE") staffing data for the 2021-27 period. These FTE planning assumptions are for all LoBs within Hydro One Networks Inc.;
- The 2021-22 figures include the repatriation of Inergi employees within Information Services, Shared Services (Supply Chain), and Finance (Accounting and Payroll). Changes reflect approximately 250 total FTEs: 155 ISD, 55 Shared Services, 40 Finance + Pay; and
- In 2023-27, there will be minor increases in the level of FTEs within the regular and casual workforce of Transmission and Distribution to meet the growing workload demands as a result of the execution plans of these organizations.

The rigorous and LoB-targeted workforce planning process has resulted in planned FTE levels that correspond to the objectives of efficiency, safety, cost-effectiveness and customer-focused outcomes. Business services and corporate functions are right-sized, and are equipped to support the increase in work required to meet its strategic objectives.

Corporate and Centralized Operating Costs

Hydro One utilizes a centralized shared services model to deliver common services to its affiliated companies. Affiliates are allocated a share based on the output of a cost allocation methodology developed by a third party expert, Black and Veatch Corporation. The methodology has been reviewed in detail and refreshed, and will be presented as evidence for the JRAP, however, it is materially consistent with the methodology previously approved for use by the OEB.

The majority of corporate and centralized operating costs ("corporate costs"), approximately 90%, are allocated to the Transmission and Distribution businesses under Hydro One Networks Inc. As well, the cost allocation methodology allows for a portion of these costs, when ascertained to have a casual link to capital activity, to be capitalized based on the proportional spend of the Company's capital work program relative to OM&A. The remaining balance is allocated to Hydro One's affiliates and subsidiaries. Costs subject to Bill 2 legislation are not included in rates. **Planned corporate costs are summarized below:**

$mm	2019 *Actuals*	2020 *Actuals*	2021 *Budget*	2022	2023	2024	2025	2026	2027	% Capex[1]
CEO and Board[2]	7	7	6	6	6	6	6	6	7	26%
Cust. and Corp. Affairs[3]	33	34	39	41	43	44	45	46	47	14%
Finance	62	52	59	60	61	62	63	64	65	46%
Human Resources	22	24	22	24	26	27	28	28	28	70%
Info. Solutions Division	15	15	14	16	17	18	18	19	19	43%
Legal & Secretariat	34	34	33	35	33	34	39	37	38	27%
Operations	90	87	91	95	96	97	99	102	105	48%
Other[4]	1	2	2	2	2	2	2	2	2	43%
Total	**$264**	**$255**	**$266**	**$279**	**$284**	**$290**	**$300**	**$304**	**$311**	

Hydro One leadership undertook a process to review corporate costs during the 2019-24 planning period. The result was a significant reduction in planned OM&A spend relative to prior plans. These reductions were submitted as part of the 2020-22 Transmission rate application, and Hydro One continues to maintain a commitment to these lower corporate cost targets as submitted. The planned corporate spend in 2022 includes $6 million of incremental cost primarily related to an actuarial update to Hydro One's pension burden relative to prior valuations. Additionally, the costs in 2025 include $5 million of additional funding to support regulatory activities related to the next anticipated major rate application filing for 2028 rates. Lastly, corporate costs reflect the insourcing of Inergi Finance and transitioning HR Pay to Ceridian.

OEB-Directed Reviews and Benchmarking of Corporate Costs

In the decisions received for the 2018-22 Distribution and 2020-22 Transmission rate applications, Hydro One was directed by the OEB to file a detailed review of its common

[1] Capital percentage is an approximation across all Plan years using a methodology recommended by Black and Veatch.
[2] Includes CEO (not recoverable in rates), CEO Office, Chair, Board, and Ombudsman.
[3] Excludes bad debt.
[4] Includes costs for staff relating to Long Term Disability benefits.

corporate costs and shared assets allocation methodologies as part of the JRAP. In addition, the Distribution decision stated that the OEB expects Hydro One to expand its benchmarking efforts to include corporate costs. To this end, Hydro One undertook competitive RFP processes to select appropriate vendors to assess its common corporate cost allocation and overhead capitalization methodologies, as well as to benchmark Hydro One's centralized and shared corporate costs.

Review of Methodologies for Allocating and Capitalizing Corporate Costs

Black and Veatch was selected to take a detailed and critical look at the methodologies for the allocation and capitalization of corporate costs. For the allocation review, enhancements were made to the methodology on the basis of best practices. Overall, Black and Veatch found that Hydro One's corporate cost allocation methodology is appropriate, distributes costs in a manner that is consistent with OEB precedent and regulatory practice, ensures legislative compliance, and promotes transparency and efficiency. Results were similar when compared to methods used in the past with respect to the percentage of corporate costs allocated between the Tx and Dx businesses and Hydro One's other affiliates and subsidiaries.

Black and Veatch's review of the methodology for capitalizing corporate costs included additional enhancements, resulting in a higher proportion of corporate costs being directly allocated to either OM&A or capital. The increased Capital portfolio in Dx and Tx has contributed to a relative decrease of capitalized corporate costs compared to the previous plans, with the capitalization rate in the Dx and Tx businesses decreasing from 14% and 10% in 2022 to 9% and 8% in 2023, respectively. Overall, Black and Veatch found that Hydro One's corporate capitalization methodology is appropriate because it is accurate and transparent, and fairly attributes to and recovers appropriate overhead costs for capital expenditures.

Benchmarking of Corporate Costs

UMS Group was selected to conduct benchmarking of Hydro One's corporate costs to a comparator group of utilities in North America. Overall, the corporate costs benchmarked well relative to the comparator group: Hydro One is at or near 1st quartile levels for 5 functions and median levels for 4 functions. There were no functions that benchmarked in the 3rd quartile.

Function[1]	Normalizer	Hydro One	1st Quartile	Median	3rd Quartile
Corporate Management	$mm of Revenue	**$2,701**	$1,232	$2,490	$4,692
Finance	$mm of Revenue	**$5,777**	$4,472	$5,777	$8,371
Real Estate	# of Employees	**$1,150**	$1,205	$1,983	$3,630
Human Resources	# of Employees	**$2,612**	$2,601	$3,226	$4,538
Legal	$mm of Revenue	**$2,048**	$2,170	$2,848	$3,649
Regulatory Affairs	$mm of Revenue	**$1,695**	$1,107	$1,695	$2,088
Asset Mgmt Planning	$mm of Net Assets	**$1,598**	$1,529	$2,749	$5,774
Corporate Affairs	# of Customers	**$6.20**	$6.00	$9.40	$15.20
System Operations	Circuit kM	**$323**	$304	$321	$429

[1] The Functions identified in the UMS report are not directly comparable to the internal functions, as re-mapping was required by UMS to better align with peer groups. This was necessary to allow for a better comparison against peers. 2019 Actuals were used as the basis of the benchmarking study.

Productivity Savings

Hydro One's commitment to achieving incremental productivity improvements and savings is central to the planning and execution of work programs. The productivity plan has enabled the Company to implement a significant number of initiatives to reduce costs while maintaining or improving service quality. The targets for JRAP have been updated with consideration of the observations outlined in the third party review performed by Concentric Energy Advisors ("Concentric") further discussed below.

Productivity Third Party Benchmarking

As a directive from the 2020-22 Transmission Rate application, the OEB indicated that Hydro One should engage an independent third party to review and report on the productivity framework, and to present the findings during the JRAP. The Company engaged Concentric to perform this assessment. The study includes both (i) an independent assessment of the productivity framework, and (ii) a benchmark comparison to comparable frameworks from peer companies. More specifically, Concentric's scope of work included the following tasks:

1. Assessing the Productivity Framework in terms of (i) its effectiveness to identify and quantify improvements and initiatives; (ii) its application of baseline data; (iii) its validation and audit process, (iv) the extent to which the identified savings can be considered true gains, and (v) how it is considered in forward-looking planning; and
2. Identifying an appropriate peer group of utilities to compare the frameworks employed, including the effectiveness of the framework in identifying, measuring, tracking and validating productivity savings.

Concentric's productivity governance report concluded that Hydro One's productivity framework:

- Stands out as being uniquely robust, well defined, and transparent;
- Is more rigorous and challenging than industry standards; and
- Is differentiated by the incentive compensation process and degree of regulatory review.

Additionally, the report concluded that most other utilities do not have a clearly defined productivity program, and those that do often focus their efforts on one-time transformational synergies. Concentric also suggested that execution relative to the framework's rigorous standards will become increasingly challenging as new and incremental initiatives will need to be identified to achieve targets going forward over the long term.

In an effort to continuously improve, based on the results of the productivity governance report, Hydro One is enhancing its existing productivity framework by resetting baselines to align with the JRAP. This change will demonstrate a clear link to the JRAP period, will cease external reporting of legacy initiatives on a cumulative basis and will simplify the governance and reporting process.

Additionally, Hydro One will continue to embrace Progressive Productivity commitments as a tool to manage delivery to the applied productivity factor and supplemental stretch on capital for each of Tx and Dx through continuous improvement.

Productivity Achievements Relative to OEB Commitments

Distribution 2018 22	**2018** *OEB vs Actual*	**2019** *OEB vs Actual*	**2020** *OEB vs Actual*	**2021** *OEB vs Plan*	**2022** *OEB vs Plan*	**Total**
Capital Actuals/Plan	39	49	61	77	73	**299**
Rate Filing	39	36	40	40	41	**196**
Plan vs. Filing - Capital	**$0**	**$13**	**$21**	**$37**	**$32**	**$103**
OM&A Actuals/Plan	36	48	86	81	108	**358**
Rate Filing	31	36	43	45	47	**202**
Plan vs. Filing - OM&A	**$5**	**$12**	**$43**	**$36**	**$61**	**$156**

For Distribution, incremental capital savings for 2018-20 relative to the rate filing were primarily driven by annual reductions in Fleet capital replacement costs through the utilization of telematics data and by improved planning in distribution station designs, which enabled the deployment of lower cost infrastructure. Incremental OM&A savings were primarily driven by insourcing of the Customer Call Center through actual cost reductions versus the annual cost of the prior agreement with Inergi, shifting the completion of Cable Locates to lower cost outsourced service providers, and from renegotiating the IT Outsourcing contract with Inergi. For 2021-22, incremental to the aforementioned capital initiatives, unit cost reductions in the Pole replacement program are estimated to be enabled through centralized planning.

Transmission 2020 22	**2020** *OEB vs Actual*	**2021** *OEB vs Plan*	**2022** *OEB vs Plan*	**Total**
Capital Actuals/Plan	82	100	130	**312**
Rate Filing	76	101	123	**300**
Plan vs. Filing - Capital	**$6**	**-$1**	**$7**	**$12**
OM&A/Revenue Actuals/Plan	46	37	40	**123**
Rate Filing	22	25	23	**70**
Plan vs. Filing - OM&A/Rev.	**$24**	**$12**	**$17**	**$53**

For Transmission, for 2020 actuals, incremental capital savings relative to the rate filing were driven by procurement initiatives, which enabled savings through negotiating volume discounts; feedback rounds; installing catalogue buying via new SAP tools and compliance enforcement. These capital savings are driven by reduced expenditures for power quality equipment and operating efficiencies in Station Services. Incremental OM&A/Revenue savings were primarily driven by Secondary Land Use Revenues, renegotiating the IT Outsourcing contract with Inergi and cost reductions from stations work methods efficiencies. For 2021-22, in addition to the aforementioned capital initiatives, savings are forecast to be achieved due to innovative planning to reduce the number of transformers and associated equipment compared with their like-for-like replacement.

Productivity Strategy

In operationalizing the Corporate Strategy, Hydro One remains committed to achieving an incremental $50 million per year, or approximately 1.5% of total work program spend, of quantified savings. This focus on incremental savings is one of the key drivers that impacts Hydro One's ability to offset the impacts of inflation. To illustrate, Hydro One's productivity program has contributed to a reduction in OM&A since the Initial Public Offering.

Productivity in JRAP

One of the observations from Concentric's review of industry best practise is that re-baselining is a key pillar of an effective program, and typically coincides with "transformational" events or achieving incentives embedded in ratemaking structures. In consideration of this, Hydro One plans to enhance its program by resetting baselines to coincide with the JRAP. The refreshed baseline will be used to measure and track future savings. This reset will also help address intervenor concerns or questions about whether the program is largely legacy based. While maintaining run-rate savings will remain important, legacy initiatives will be considered regular course of business in 2023, unless they are able to demonstrate incremental savings over and above the new baseline. Also, as previously described, instead of applying an additional bottom line reduction to the capital envelope in respect of progressive productivity, Hydro One will provide customers an upfront revenue requirement reduction by applying the productivity factor and supplemental stretch on capital for each of Dx and Tx. The $50 million strategic target will be used to execute against the productivity factor and supplemental stretch on capital included in revenue requirement, without compromising work outcomes. Hydro One's ability to meet the targets in the 2023-27 Plan will result in achieving the productivity factors and supplemental stretch on capital proposed in the CIR Framework. Hydro One has demonstrated the ability to execute to the commitments made in the prior Distribution and Transmission applications, and will continue to find new and innovative ways of completing work, to the benefit of all stakeholders.

[1] Actual as filed in Dx 2018-22 and Tx 2017-18 applications.
[2] Excludes Secondary Land Use Revenue.
[3] Actuals to be filed in JRAP 2023-27 application.

Financing Assumptions

Hydro One Inc.'s fixed rate long-term debt is maintained at 56% of rate base throughout the Plan to align with OEB deemed capital structure, with the remainder of the debt component made up of floating rate debt. The issuance of debt with standard terms to maturity preferred by investors (5, 10 and 30 years) is assumed to be the core financing to meet the fixed rate borrowing requirements. The actual term of debt issuance will depend on market conditions and investor preferences at the time of issuance. The floating rate requirement will be funded through floating rate notes, fixed rate debt swapped to floating rate and commercial paper.

The forecast bond rates in the table below are the summation of Government of Canada bond forecasts and the Hydro One credit spread. Forecast Government of Canada bond interest rates are consistent with OEB methodology using September 2020 Consensus Forecast for 2021 and October 2020 Long Term Consensus Forecast for 2022-27. Forecast Hydro One credit spreads are based on the actual average spreads for September 2020 and are assumed to prevail through the Plan. The table below provides the assumed debt issuances, which increase in 2023 to support the growth in the capital work program and forecast interest rates, which shows an expected gradual increase. Hydro One has the ability to fund the increased capital requirements as evident from the 2020 long-term debt issuance of $2.3 billion, out of which approximately $1.6 billion were allocated to Tx and Dx businesses.

Financing Assumptions[1]	2020A	2021	2022	2023[2]
Fixed Rate Issuances ($mm)				
2-5 year issuance	474	171	376	412
7-10 year issuance	674	171	376	412
30-31 year issuance	405	171	376	412
Total Fixed Rate issuance	$1,553	$512	$1,129	$1,237
Interest Rate Forecast				
5-year		1.33%	2.08%	2.48%
10-year		1.86%	2.61%	3.01%
30-year		2.86%	3.61%	4.01%

As part of the Draft Rate Order process, Hydro One will update the forecast long-term debt rate for 2023 based on Hydro One's actual 2021 and 2022 debt issuances to-date and forecast debt issues in 2023 with coupon rates based on the 2022 September Consensus Forecast, consistent with the proposed update of the ROE and deemed short-term interest rate.

The cost of debt has declined since the last OEB approved applications. Since the prior filings were approved, the weighted average long term debt rate for Dx declines from 4.47% to the current projection of 4.07% for 2023, and for Tx declines from 4.42% to the current projection of 4.04% for 2023. For 2023, the deemed short term debt rate for Dx declines from 2.29% to 1.56%, and for Tx declines from 2.75% to 1.56%.

[1] Financing assumptions relate to Transmission and Distribution cost of long-term debt to be filed in JRAP.

[2] Consistent with prior filings, updates are intended to be made in Q4 2022 to align with the OEB's allowed ROE for 2023, up-to-date actuals for issued debt in 2022, and interest rate forecasts for 2023.

Credit Ratings

Hydro One Inc.'s S&P Global Ratings ("S&P") debt rating of "A-" stable outlook should be maintained, and is in line with the "A" category credit ratings of other Ontario peer companies, such as Toronto Hydro and Alectra Utilities. S&P, one of the largest credit rating agencies, notes that "regulatory frameworks for electricity and gas transmission and distribution networks in Ontario exhibit characteristics that are consistent with our most credit supportive (strong) regulatory advantage assessment." [1]

With regard to Hydro One Inc.'s credit rating, S&P notes that "the OEB is the provincial regulator and provides a generally transparent, consistent, and independently operated regulatory framework that supports a stable and predictable cash flow model. We view this as a key credit strength." [2] Maintaining Hydro One's credit ratings help to ensure a lower cost of debt and more predictable access to the debt capital markets, which benefits customers.

Hydro One Inc. Credit Ratings

Rating Agency	Short term Debt Rating and Outlook		Long term Debt Rating and Outlook	
DBRS Limited	R-1 (low)	Stable	A (high)	Stable
Moody's	Prime-2	Stable	A3	Stable
S&P	A-1 (low)	Stable	A-	Stable

[1] S&P Global Ratings, Why We See Ontario's Electricity And Gas Regulatory Framework As Strong, January 13, 2021.
[2] S&P report on Hydro One Inc. dated February 24, 2020.

Business Plan Opportunities & Risks

Risk & Opportunity	Description	Estimated Potential Impact *Figures are estimates and subject to change*	Mitigation Considerations
Demand and Consumption	Peak load for Tx and consumption for Dx is forecast in each rate application. Realized experience is based on actual demand and consumption, which may differ.	1,000 MW change in Tx peak load in any month = $7mm revenue impact. 100 kWh change for all average R1 customers in a month = $4mm revenue impact.	As part of an application update, latest available information will be utilized to update the load forecast. Hydro One may seek a mid-term update for the load forecast later in the Application, should any material changes to economic forecasts arise.
Capital Expenditures	OEB approval of Capital Expenditures presented in the JRAP.	$100mm reduction of capital expenditures reduces the allowed equity component of revenue requirement by $4mm.	Customer engagement, plan prioritization, and productivity show Hydro One is making prudent decisions while providing customers upfront benefit.
Interest Rates	Plan includes fixed rate and floating rate debt financing. The cost of debt will be updated in Q4 of 2022, for rates effective 2023-27.	1% change in the cost of borrowing = $47mm average annual interest impact from 2023-27.	As part of the application process, Hydro One may seek a mid-term update for Cost of Capital parameters (interest rates and ROE) later in the Application, to reflect changes due to economic uncertainties and other factors.
OEB Allowed ROE	Current OEB approved ROE for 2021 is 8.34%, and the forecast for 2023 is 8.83%. ROE will be updated in Q4 2022, for rates effective 2023-27.	1% change in ROE = $95mm change to the allowed equity component of revenue requirement and changes Tx and Dx revenue requirement in 2023 by 4.5% and 3.1%, respectively.	
COVID-19 – Operations	The pandemic creates additional uncertainties. The extent is uncertain, and depends on the severity and duration. No incremental COVID-19 costs have been planned during 2023-27.	As of March 2021, OM&A run rate for incremental COVID-19 costs is $1mm per month. This includes janitorial services, supplies, and external fleet rentals supporting safe operations.	Plan assumes that by 2023, no material impacts will exist. If impacts are sustained, Hydro One will update the forecast costs as part of the application process. Otherwise, it will be managed by incremental productivity in other areas of the business.
COVID-19 – Bad Debt	Bad Debt is $18mm per the Dx 2018-22 OEB approval. For 2023, this amount is held flat. The pandemic and uncertainty relating to customer collections and overdue accounts receivable poses a material risk relative to OEB approved levels.	For 2021-22, ~$13mm annual risk related to sustained impacts. For 2023+, since levels will be filed flat relative to prior OEB approved, if the impact of the pandemic is sustained, the risk may persist until economic conditions recover.	

Retail Settlements Variance Account	Regulatory account which requires distributors to record differences between amount owed to the IESO and amount billed to customers and retailers. It is difficult to forecast future balances as account depends on cost of power forecasts for both retail and wholesale markets.	As at year-end 2020, $69mm is set to be refunded to customers. Given large fluctuations to this account can occur, the Application update for 2021 audited actuals may include material rate changes relative to figures filed in initial evidence. A $50mm change would impact Dx revenue requirement by 0.6% in 2023.	Disposing any refund/recovery over the entire JRAP term will mitigate any potential rate shock associated with such large balances.
Earnings Sharing Mechanism	Hydro One remains committed to incentive rate making. As previously described, Tx and Dx will have ESMs, which incent the Company to find additional savings to the benefit of customers and shareholders.	By leveraging the productivity framework, the Company will strive to find additional sustained savings without sacrificing work output. As well, other regulated upside, like revenue, can also impact the any incremental benefit sharing.	Not applicable.

Appendix A: 2021-27 OM&A Table

Hydro One's OM&A for Transmission and Distribution in the first year of the 5-year period (2023) is determined using a cost of service, forward test year approach, consistent with the OEB's RRF. The OM&A in the following years, 2024-27, is determined using an OEB approved inflation factor calculated and issued by the OEB annually less Hydro One's Custom Productivity Stretch Factor that is calculated for both Hydro One Transmission and Hydro One Distribution. The OM&A identified below for Transmission and Distribution represents total OM&A in the rebase period (2023) that is being filed with the OEB for approval. This includes OM&A related work program, corporate common costs, overheads recovered, property taxes, and other OM&A costs.

Distribution OM&A ($mm)	2021	2022	2023	2024	2025	2026	2027
Work Program OM&A	512	512	520				
Corporate Common Costs	127	134	140				
Overheads Recovered	-89	-91	-90				
Property Taxes	6	6	6				
Environmental Provision[1]	-13	-13	0				
OPEB non-service costs	0	0	20				
Other[2]	-10	-11	-5				
OM&A Total[3]	**$533**	**$537**	**$591**	**$602**	**$613**	**$625**	**$637**

Transmission OM&A ($mm)	2021	2022	2023	2024	2025	2026	2027
Work Program OM&A	314	316	333				
Corporate Common Costs	122	130	131				
Overheads Recovered	-115	-120	-118				
Property Taxes	69	70	71				
Environmental Provision[1]	-16	-16	0				
OPEB non-service costs	16	17	17				
Other[2]	2	-2	-6				
OM&A Total	**$392**	**$394**	**$428**	**$437**	**$445**	**$454**	**$463**

[1] Environmental Provision relates to PCB Retirement and Waste Management program. Regulations require this program to be completed by 2025. Historical costs are partially re-classed to depreciation expense. For 2023, Hydro One is requesting recovery via OM&A to enable sustainment OM&A funding to correspond with Sustainment OM&A work.
[2] Other includes cost of external work, and corporate level adjustments.
[3] Excludes Acquired LDCs. Refer to Investment planning section for Acquired LDCs OM&A details.

Appendix B: Acronyms, Abbreviations and Terminology

Acquired LDCs	Norfolk Power Inc., Haldimand County Utilities Inc., and Woodstock Hydro Services Inc.
AMI	Advanced Metering Infrastructure
Application	2023-27 Joint Rate Application
Board	Hydro One's Board of Directors
CIR	Custom Incentive Rate-Setting
CISVA	Capital In-Service Variance Account
Company	Hydro One Ltd.
Concentric	Concentric Energy Advisors
CDM	Conservation and Demand Management
Corporate costs	Corporate and centralized operating costs
Corporate Strategy	2019 Corporate Strategic Plan
CUSW	Canadian Union Of Skilled Workers
DSP	Distribution System Plan
Dx	Distribution
EPSCA	Electrical Power Systems Construction Association
ESM	Earnings Sharing Mechanism
FTE	Full-time equivalent
HSEMS	Health, Safety and Environmental Managed Systems
Hydro One	Hydro One Ltd.
IESO	Independent Electricity System Operator
Inergi	Inergi Limited Partnership
ISD	Information Solutions Division
IT	Information Technology
JRAP	2023-27 Joint Rate Application
LDCs	Local Distribution Companies
LIUNA	Laborers' International Union of North America
LoBs	Lines of business
MCP	Management compensation plan
MGT	Management
Moody’s	Moody’s Investors Service
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OM&A	Operations, Maintenance and Administration
OPEB	Other Post-Employment Benefit
PCBs	Polychlorinated Biphenyls
Plan	2023-27 JRAP Business Plan
PMOLT	Project Management Oversight & Leadership Team
PWU	Power Workers’ Union
RCI	Revenue Cap Index
RFP	Request for Proposals
ROE	Return on Equity
RRF	Renewed Regulatory Framework
S&P	Standard & Poor’s
SAIDI	System Average Interruption Duration Index
Society	Society of United Professionals
T&S	Transmission & Stations organization
TSP	Transmission System Plan
Tx	Transmission

CUSTOM IR APPLICATION SUMMARY

1.0 APPLICATION STRUCTURE AND RCI COMPONENTS

This Application is based on a Custom Incentive Rate-Setting (IR) approach for a 5-year period. The methodology 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). The methodology is similar for both the Transmission and Distribution businesses. This exhibit describes the elements of this methodology, and details regarding the specific parameters for the Transmission and Distribution businesses are provided in Exhibits A-04-02 and A-04-03, respectively.

The Custom RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index;
- "X" is the Productivity Factor, 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, designed to recover incremental revenue each year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.15%.

The revenue requirement in the first year of the 5 year period (2023) is determined using a cost of service, forward test year approach, consistent with the OEB's Renewed Regulatory Framework (RRF) as more recently set out in the Handbook for Utility Rate Applications (the Handbook). The revenue requirement in each of the following years, 2024-2027, is determined using the RCI. The proposed methodology is generally consistent with the approach approved by the OEB in Hydro One's prior Transmission and Distribution proceedings (EB-2019-0082 and EB-2017-0049). Hydro One engaged an independent consultant, Clearspring Energy Advisors (Clearspring), to undertake various benchmarking analyses to support the specific parameters of Hydro One's Custom RCI. The Clearspring study is provided in Exhibit A-04-01-01.

1.1 CHANGES TO THE FRAMEWORK

Hydro One's overall approach is consistent with the RRF and with the Custom RCIs approved by the OEB for Hydro One Distribution in EB-2017-0049 and for Hydro One Transmission in EB-2019-0082. However, Hydro One is proposing the following additions or adjustments compared to the RCIs it proposed in those prior applications, to the benefit of ratepayers:

1. Hydro One is adding a supplemental stretch factor of 0.15% to the capital related revenue requirement (Supplemental Stretch);
2. The productivity factors which form the X-factor, as well as the Supplemental Stretch on capital, are being applied cumulatively to the capital related revenue requirement in each year of the Custom IR term; and
3. The C-factor will be updated annually to reflect any changes to inflation.

1.2 ELEMENTS OF THE CUSTOM RCI

The individual elements of Hydro One's proposed Custom RCI are described below.

1.2.1 INFLATION FACTOR

The proposed Inflation Factor (I) is based on the weighted average of the annual percent change of two labour and non-labour indices, namely:

- Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The industry-specific weightings and pro-forma Inflation Factors for the Transmission and Distribution businesses are set out in Exhibits A-04-02 and A-04-03, respectively. The Inflation Factor will be updated annually to reflect the latest values issued by the OEB.

1.2.2 X-FACTOR

The X-factor is the sum of two productivity factors: a base productivity factor which reflects the long-term industry productivity trend, and a stretch factor which reflects the results of an independent total cost benchmarking study conducted by Clearspring, provided in Exhibit A-04-01-01. 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 – this is in addition to sustained and ongoing productivity savings embedded in Hydro One's business plan during the Custom IR term, as described in SPF Section 1.4. Exhibits A-04-02 and A-04-03 detail the values for the X-factor, as derived from the Clearspring study in Exhibit A-04-01-01.

1.2.3 CUSTOM CAPITAL FACTOR

The C-factor is designed to ensure that the total revenue resulting from the Custom IR approach is appropriate for Hydro One's specific circumstances and will support the necessary capital investments in Hydro One's TSP, DSP and GSP, while also ensuring that appropriate incentives are in place with up front benefits to ratepayers.

The C-factor is the percentage change in the total revenue requirement attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. It includes depreciation, return on equity, interest and taxes attributable to new capital investments placed in-service each year of the Custom IR term. The working capital allowance is not included in the derivation of the C-factor, consistent with the OEB's decision in Hydro One's most recent Custom IR proceedings (EB-2019-0082 and EB-2017-0049).

To incent further productivity and continuous improvement, and provide an upfront revenue requirement reduction to customers, Hydro One is proposing a Supplemental Stretch on capital of 0.15% in respect of both the Transmission and Distribution businesses. The Supplemental Stretch will align with Hydro One's recent Custom IR proceedings, in which the OEB ordered a 0.15% supplemental stretch on capital in order to further incent Hydro One to seek productivity gains.[1] Hydro One will use its productivity framework, described in SPF Section 1.4, to achieve this Supplemental Stretch (along with the X-factor), and to ensure Hydro One is meeting its planned deliverables and outcomes at a lower cost.

The Supplemental Stretch, along with the X-factor described above, will be applied in a cumulative manner in each year of the test period. This results in a significant upfront revenue requirement reduction for customers. Details on the calculation of the C-factor are provided in Exhibits A-04-02 and A-04-03.

1.3 ADDITIONAL CUSTOM IR FEATURES

Hydro One is proposing the following additional features to align its interests with those of customers and to provide additional elements of protection for customers.

1.3.1 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 for each of Hydro One Transmission and Hydro One Distribution. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a 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. Further details on Hydro One's ESM are provided in Exhibits G-01-01 and G-01-02.

[1] EB-2017-0049, Decision and Order, p. 32 and EB-2019-0082, Decision and Order, p 39

1.3.2 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 and the revenue requirement associated with OEB-approved in-service capital additions.

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[2] that, on a cumulative basis, are lower than 98% of the OEB-approved amount for each year of the Custom IR term;
2. For cumulative in-service additions that are lower than 98% of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account;
3. The CISVA for Hydro One Distribution will, as in the past, require that the sum of the variances in each year be disposed of to the benefit of customers at the end of the Custom IR term;
4. In the case of the CISVA for Hydro One Transmission, Hydro One requests that the CISVA be modified to enable the balance in the account to be calculated yearly using the cumulative in-service additions over the Custom IR term so as to provide an opportunity for Hydro One to "catch-up" in later years within the term on any shortfalls in in-service additions that may occur in earlier years, and thereby to reverse the applicable impact recorded in a prior year of under in-servicing to the extent it makes up for such a shortfall, as described in Exhibit G-01-02, Section 4.3. Thus, the final balance at the end of the Custom IR term will be disposed of to the benefit of customers; and

---

[2] As described in Sections 4.2, 7.2 and 7.4 of Exhibit G-01-02, the amounts used to calculate the balance in Hydro One's Externally Driven Distribution Projects Variance Account, AMI 2.0 Variance Account and Externally Driven Transmission Projects Variance Account will be excluded from the Capital In-Service Variance Account, as applicable.

5. The final balances for the Hydro One Transmission and Hydro One Distribution CISVAs, respectively, will be disposed of with the following conditions:
   - The revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
   - The 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 amount will be recoverable from ratepayers.

Hydro One believes that a dead band continues to be appropriate for the CISVA in order to ensure alignment between the behaviours that are incented by the account and the outcomes that ratepayers value. A 2% dead band was approved for this account in EB-2017-0049 and EB-2019-0082.[3] Further details on the features of the CISVA are provided in Exhibit G-01-02.

2.0 Z-FACTOR

Hydro One is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available during this Custom IR term. The criteria that Hydro One proposes to apply to the use of the Z-factor mechanism are those approved by the OEB in EB-2017-0049 and EB-2019-0082.[4] Specifically, Z-factor claims must be outside the control of Hydro One to manage, exceed a $3M materiality threshold on a revenue requirement basis, and meet all of the following criteria on an individual event basis:

---

[3] EB-2017-0049 Decision and Order, p 173; EB-2019-0082, Decision and Order, p 172
[4] EB-2017-0047 Decision and Order p 42; EB-2019-0082 Decision and Order, p 41

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed $3M on a revenue requirement basis and have a significant influence on the operation of the utility; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the utility's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

3.0 OFF-RAMPS

Hydro One proposes to apply the OEB's existing policy with respect to off-ramps, in which a regulatory review may be triggered if a utility's performance falls outside of an equity dead band of plus or minus 300 basis points. This approach is consistent with the OEB's decisions in EB-2017-0049 and EB-2019-0082.

4.0 PROPOSED FRAMEWORK FOR UPDATES

Hydro One expects to file annual update applications from 2024-2027. Details regarding these applications are set out in Exhibits A-04-02 and A-04-03.

This page left blank intentionally.

Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application

PREPARED BY:

CLEARSPRING ENERGY ADVISORS

CONTACT: STEVE FENRICK

STEVE.FENRICK@CLEARSPRINGENERGY.COM

JULY 30, 2021

Clearspring Energy Advisors LLC

Contents

List of Tables and Figures

1 Executive Summary

Hydro One Networks ("Hydro One" or "Company"), through counsel, engaged Clearspring Energy Advisors, LLC ("Clearspring") to conduct benchmarking and productivity research for the Company's transmission and distribution joint rate application ("JRAP"). The lead researcher of the study is Mr. Steven A. Fenrick. Mr. Fenrick provided research reports and expert witness testimony on behalf of Hydro One in the Company's most recent transmission and distribution rate applications, and has extensive experience conducting these types of studies.[1,2] A copy of Mr. Fenrick's summary *curriculum vitae* is attached as Appendix D.

A new feature in this research and report is the calculation and industry comparison of the capital age of assets for Hydro One's transmission and distribution infrastructure. This calculation uses industry data going back to 1948 and is done independently of the total cost benchmarking and productivity trend research.

1.1 Research Study Components

The research conducted and described in this report includes studies for both the transmission and distribution businesses of Hydro One. These studies are:

- **Transmission and distribution total cost benchmarking of Hydro One**. This study – done for each of the transmission and distribution businesses – is the basis for our recommendation for stretch factors in the Company's custom incentive regulation ("CIR") proposal for each business.

- **Transmission and distribution capital age calculation**. This study – done for each of the transmission and distribution businesses – supports and helps explain the cost benchmarking scores of the Company and the transmission industry total factor productivity ("TFP") trend.

- **Transmission industry TFP trend**. This study is the basis for our recommendation for the transmission base productivity component of the X-factor in the Company's CIR proposal.

- **Relationship between capital spending and OM&A expenses**. This study is in response to a request by the OEB in the last Hydro One transmission decision.

1.2 Transmission Research Study Results

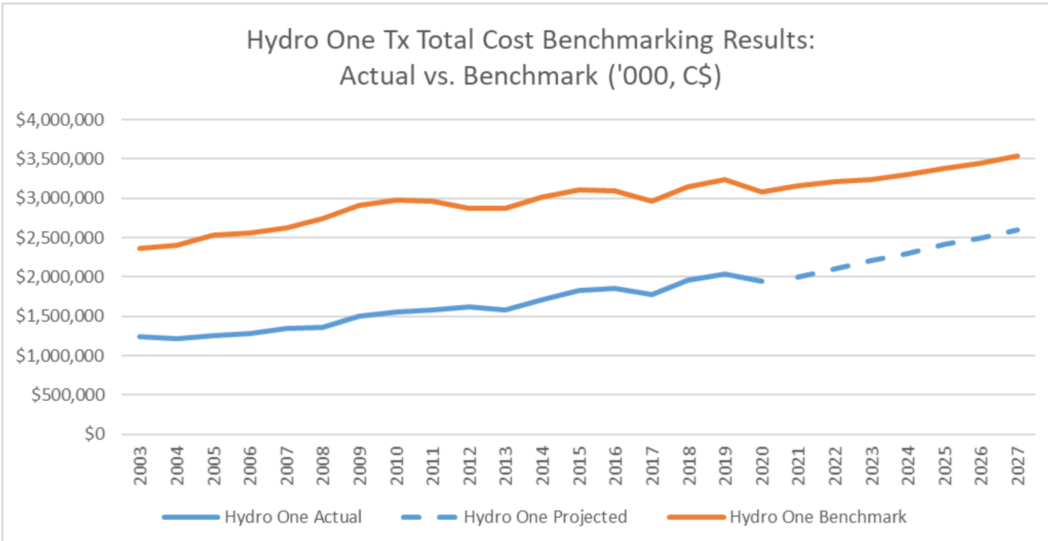
Clearspring benchmarked Hydro One's total transmission historical and forecasted costs from 2003 to 2027. Hydro One's transmission total cost benchmarking showed a forecasted total cost performance of

[1] The Transmission application was EB-2019-0082. The Distribution application was EB-2017-0049.

[2] Mr. Fenrick was an employee of Power System Engineering, Inc. ("PSE") and both prior Hydro One reports were produced when Mr. Fenrick was with PSE. Throughout this report, prior PSE benchmarking studies will be referred to as "Mr. Fenrick's studies" or "our" studies, as Mr. Fenrick was the primary researcher for all prior PSE benchmarking and productivity studies conducted in Ontario.

-34.5% during the CIR period of 2023 to 2027.[3] The Company's proposed transmission costs from 2023 to 2027 are 34.5% below the econometric transmission total cost model's benchmark, given the service territory conditions of Hydro One and the spending and variable forecasts of the Company.

Figure 1 Hydro One Transmission Total Cost Benchmarking



Hydro One's ranking among the transmission benchmarking sample substantiates this total cost performance benchmark score. Hydro One's benchmark score ranks in the top quartile.[4] The Company ranks 2nd out of the 60 utilities in the full transmission benchmarking sample.[5]

The capital age research conducted by Clearspring supports and helps to explain this transmission cost performance of the Company. The capital age compares the calculated age of assets at Hydro One to those of the industry at large. Older assets will tend to have lower capital costs, due to depreciation and capital asset inflation. A company with an older age would be expected, all else being equal, to have lower total costs and therefore a stronger benchmark score. Figure 2 shows that the Company's transmission capital age is materially older than the industry's transmission capital age in 2019.[6] This older capital age of Hydro One persists throughout the CIR period of 2023 to 2027 (based on the JRAP proposed capital investments and retirements).[7]

---

[3] This assumes the entirety of the proposed JRAP spending envelope is realized.

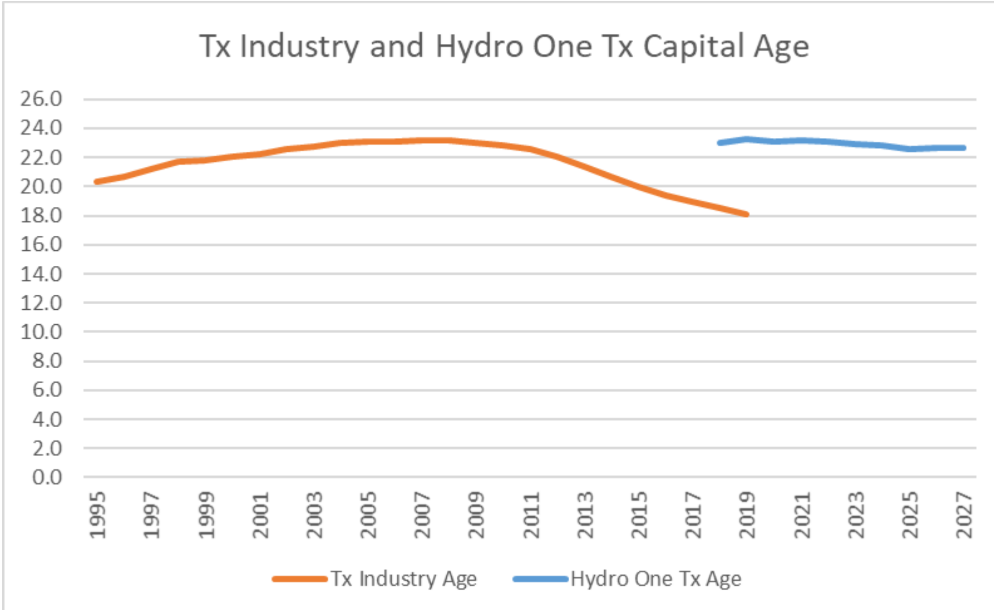
[4] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the sample ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would continue to rank 2nd in the entire sample if we used the 2017 to 2019 average for Hydro One.

[5] There are 59 U.S. transmission utilities in the sample; with Hydro One added, the full sample comprises 60 utilities.

[6] The industry's capital age is a weighted average of each utility's capital age in each year from the transmission benchmarking sample.

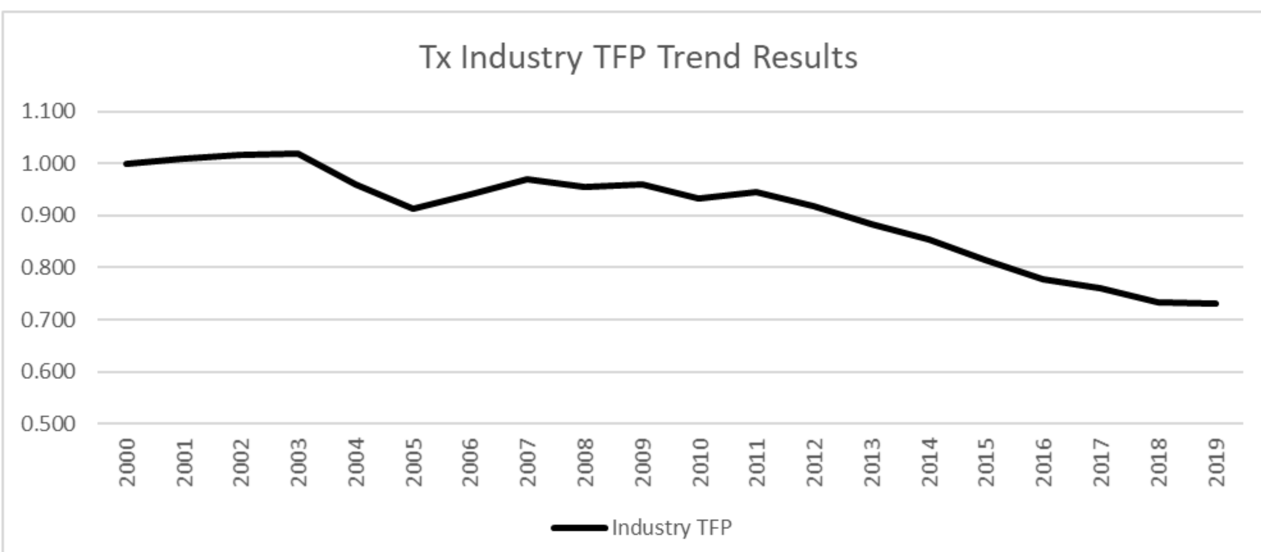
[7] Please see Section 5 and Appendix B for further details on the capital age variable.

Figure 2 Transmission Capital Age: Industry Historical vs. Hydro One



Clearspring also calculated the transmission industry TFP trend from 2000 to 2019 (see Figure 33 below), for purposes of the base productivity factor recommendation. We begin the TFP examination period in 2000, as that year immediately follows a time where a portion of the U.S. transmission industry restructured. We show that the industry TFP trend is clearly declining since 2000, and this decline has accelerated in recent years. From 2000 to 2019, the industry's TFP trend is an average annual decline of -1.66%. From 2010 to 2019, the average annual decline is -2.74%.

Figure 3 Transmission Industry TFP Trend

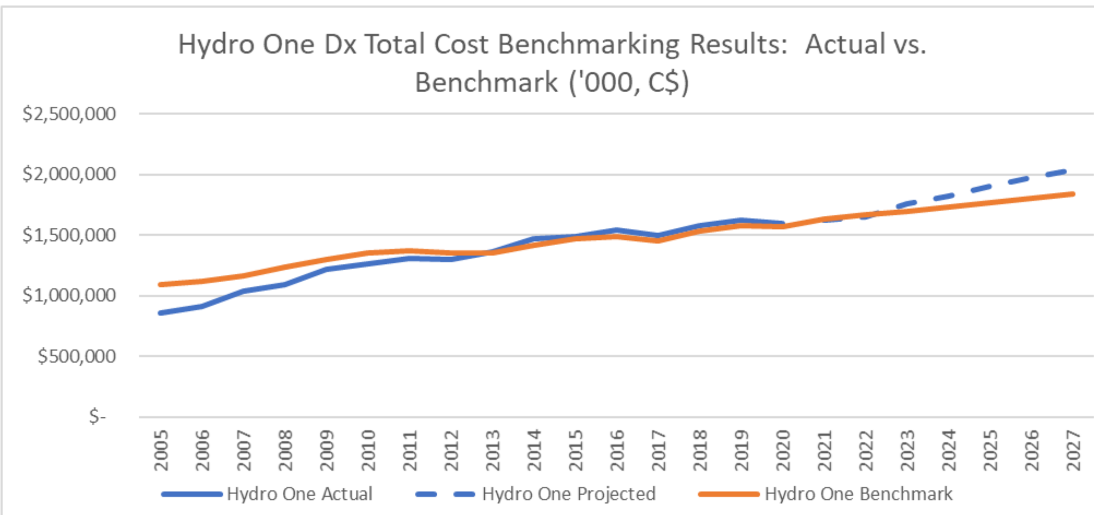


The industry's most pronounced TFP decline occurred during the period when the capital age of the industry became younger.[8] This is an expected result since it requires added capital investment to reduce the age of the system and this capital investment will also tend to lower the TFP trend. Interestingly, the industry TFP trend was also negative even during a period when the capital age of the industry became older (e.g., 2000 to 2010). This may be a result of the increasing challenges being placed on the industry (e.g., reliability, cybersecurity, DER) that is putting downward pressure on TFP not explained by the capital age.

1.3 Distribution Research Study Results

Clearspring benchmarked Hydro One's total distribution historical and forecasted costs from 2005 to 2027. Hydro One's distribution total cost benchmarking showed a forecasted total cost performance of +7.0% from 2023 to 2027.[9] The Company's forecasted distribution costs are 7.0% above the distribution total cost model's benchmark, given the service territory conditions of Hydro One and the spending and variable forecasts of the Company.

Figure 4 Hydro One Distribution Total Cost Benchmarking Results



Hydro One's ranking among the benchmarking sample substantiates this total cost performance score. Clearspring ranked the distribution sample using the three-year distribution cost performance

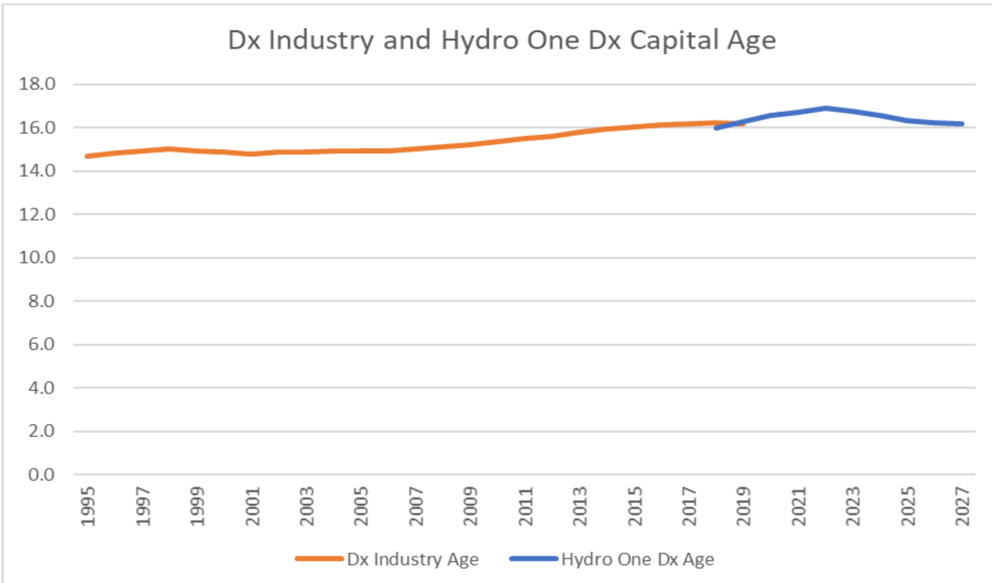
[8] A value below 1.0 in the TFP figure above indicates a negative productivity trend from the start year.

[9] This assumes the entirety of the proposed JRAP spending envelope is realized.

benchmarking score. Hydro One ranks in the third quartile.[10] The Company ranks 49th out of the 82 utilities in the full sample.[11]

The capital age research conducted by Clearspring further supports and helps to explain this cost performance of the Company (see Figure 5 below). The capital age compares the calculated age of assets at Hydro One to those of the industry at large. Older assets will tend to have lower capital costs, due to depreciation and capital asset inflation.

Figure 5 Distribution Capital Age: Industry Historical vs. Hydro One



Hydro One's distribution capital age in 2019 is near the industry's latest benchmark in 2019, which is the industry's oldest capital age level in the examined 25-year period. After 2019, Hydro One's distribution capital age is projected to slightly rise before declining back down near the 2019 level during the CIR period. This average capital age level and slight decline during the CIR period can, at least in part, be explained by Hydro One's AMI 2.0 project. AMI assets tend to have significantly shorter lives than traditional metering technology and other large distribution asset classes such as poles, conductors, and transformers. For context, if the AMI 2.0 project was not planned for during the CIR period, Hydro One's calculated capital age in 2027 would be more than a year older.[12] Absent AMI 2.0, Hydro One's distribution capital age would slightly increase during CIR and in 2027 would be 6.8% older than the industry's most recent benchmark in 2019.

---

[10] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the sample ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would rank 40th in the entire sample if we used the 2017 to 2019 average for Hydro One.

[11] There are 81 U.S. utilities in the sample and adding Hydro One makes 82.

[12] With AMI 2.0 it is 16.2 years, without AMI 2.0 it would have been 17.3 years.

1.4 Clearspring Recommendations

Our recommendations are as follows:

1. **Transmission base productivity component of the X-factor = 0.0%**. The industry TFP trend has declined since 2000, and this decline has continued to noticeably weaken in recent years for the industry.[13] While a negative base productivity factor would be reasonable, we recommend a 0.0% productivity factor, in recognition of OEB precedent in 4GIR and other CIR proceedings. However, it should be recognized that a 0.0% base productivity factor imposes a high implicit stretch factor onto the Company over 1.50%.[14] This is an extraordinary stretch factor, especially for a utility with such strong cost performance.

2. **Transmission stretch factor = 0.0%**. The transmission total cost benchmarking results of the Company indicate superior total cost benchmarking performance. The benchmark score of -34.5% shows that costs are significantly below benchmark expectations, and based on 4GIR precedent, a 0.0% stretch factor is indicated.[15] Hydro One's ranking in the top quartile among the sampled utilities, and the capital age result, further substantiate this finding. Given the following factors: (1) the superior transmission total cost performance score and ranking, (2) the transmission capital age results indicating Hydro One's capital age is substantially older than the sample, (3) the large stretch factor implicit in a 0.0% base productivity factor, and (4) the Company's proposed incremental stretch factor on capital of 0.15%, our takeaway is that a negative stretch factor should be considered and would be reasonable.

   A negative stretch factor would better reward the utility for its strong cost performance, which has provided significant cost savings to Ontario customers. Providing a strong signal and reward to utilities who are found to be superior cost performers aligns with the precepts of incentive regulation. Despite our opinion that a negative stretch factor would be reasonable in this case, we nonetheless recommend a 0.0% stretch factor in recognition of the OEB's 4GIR precedent of not allowing negative stretch factors.

3. **Distribution base productivity component of the X-factor = 0.0%**. This is based on the latest Ontario TFP study (conducted by Mr. Fenrick in the last Hydro One distribution application), and

---

[13] As discussed in Section 6, there may be good reasons for this decline in industry TFP. Increasing but unmeasured outputs such as increased reliability, cybersecurity, environmental, DER connections, geomagnetic protections, and other well-intentioned regulations may be placing higher requirements and cost challenges on utilities, without increasing the measured output growth that impacts TFP trends.

[14] Other jurisdictions have approved negative productivity factors. In Clearspring's opinion, negative productivity factors should be considered, as they would more accurately align the I-X framework with economic theory and empirical research, and substantially lessen the need for additional capital funding through other mechanisms.

[15] In the 4th Generation IR proceeding, five stretch factor groupings (cohorts) were established, based on the most recent average three-year total cost benchmarking scores. In that proceeding, a score better than -25% (i.e. costs were more than 25% below benchmark) received the lowest stretch factor of 0.00%. A score between -25% and -10% received a 0.15% stretch factor. Scores that were +/- 10% received 0.30%. Scores between 10% and 25% received a 0.45% stretch factor, and scores exceeding 25% (i.e. costs were 25% or more than benchmark) received the highest stretch factor of 0.60%.

on the 4GIR results, both of which show negative industry TFP trends.[16] The recommendation is also based on OEB decision precedents, where other CIR applications received a 0.0% base productivity factor.

4. **Distribution stretch factor = 0.3%**. The distribution total cost benchmarking results of the Company reveal average total cost benchmarking performance. The benchmark score of +7.0% indicates a 0.3% stretch factor, based on 4GIR precedent. This result is further substantiated by the distribution capital age comparison of the Company and the industry showing an average age level for the Company. In our opinion, a 0.3% stretch factor is a reasonable challenge for a utility that is estimated to be in the average cost performance range in both its benchmarking and capital age results, has already operated within incentive regulation, and is proposing a 0.15% incremental stretch factor on capital.

1.5 Reconciling Differences Between Methodologies

In several previous CIR applications, total cost benchmarking and productivity studies have been submitted by Mr. Fenrick, and OEB Staff has hired its own consultant, Pacific Economics Group ("PEG"), to conduct responding research. This reoccurring research by two benchmarking and productivity experts has produced a benchmarking methodology in Ontario that has improved and been refined over the years. This has included improvements in the service territory variables and the overall benchmarking framework. In Clearspring's opinion, the utilities in Ontario are subject to the most accurate and advanced utility benchmarking research in North America.

While some methodological differences between the experts have surfaced in past proceedings, it is important to recognize that these differences are relatively few. Clearspring has endeavored to further narrow or eliminate these differences in this current research. Clearspring examined past research and the methodological issues or questions that have been raised and has addressed these issues when that could reasonably be done without compromising the study. Please see Section 2.1 for a description of the specific methodological items addressed.

[16] In our opinion, an update to the 4GIR distribution industry TFP finding would be helpful but will require a substantial amount of effort and discussion given the accounting changes that occurred in Ontario, AMI investments, and other issues. We did not undertake to recalculate the distribution TFP trends in this application because this is best done, in our opinion, in a generic proceeding.

2 Total Cost Benchmarking Methodology

Clearspring used the same methodology for both the transmission and distribution total cost benchmarking studies. Other than the sample of utilities and the specific variables used, all other calculations and approaches are consistent. Both studies build upon prior benchmarking studies submitted in Ontario and are based on the best practices that have improved and evolved in the province.

The variables measure the impact of the variable on total cost; thus, some variables will impact transmission costs (e.g., transmission line lengths), others will impact distribution costs (e.g., customers served), and some variables will impact both costs (e.g., peak demand). Therefore, each model has its own variable specification. The samples are different because not all U.S. utilities serve both a transmission and distribution function. However, our prospective sample for each model started with the same sample "universe" of U.S. utilities, and each sample was then based on which utilities serve the applicable function and had plausible data observations for all included variables.[17]

The studies employed the econometric benchmarking approach. This is the most accurate and fair method when comparing utility cost levels because it explicitly adjusts for the quantifiable differences between utility service territories and business conditions. It is also the method preferred by the OEB in the 4GIR Report of the OEB and used for all our past CIR benchmarking research.[18]

Simple comparisons of "raw" (unadjusted) metrics such as rates, unit costs, or reliability indices do not typically allow regulators to compare utilities in a fair manner. For example, comparing a utility's costs or rates to those of a peer group utilities' costs or rates usually presents an inaccurate picture of the target utility's performance. Factors that cannot be controlled by the utility affect cost levels. Such factors include geographical size, regional wage levels, rural density, or serving a congested urban territory. It is often difficult or impossible to account for these factors using a peer group approach.

Adjusting for these and other influencing factors is necessary to accurately evaluate performance. With this concept in mind, Clearspring has estimated two econometric models (one for transmission and one for distribution) from a large sample of utilities, using variable parameters that statistically are drivers of transmission and distribution utility costs.[19] The econometric method adjusts for service territory conditions and other factors that affect total costs.

Using a large sample of utilities, the econometric model produces an industry-wide estimation of how the variables affect the studied metric (e.g., total costs). For the present research, the sample used to estimate the models includes U.S. observations from multiple utilities for multiple years.

---

[17] The U.S. sample is comprised of investor-owned utilities who are required to file a FERC Form 1. The Form 1 report includes expenses according to the Uniform System of Accounts, customers, peak demands, and plant information by function that allows us to ensure definitional consistency between Hydro One and the sample.

[18] EB-2010-0379.

[19] To "estimate" a model means, roughly, to examine the drivers or variables that affect the given metric (e.g., cost), and to use the data to create a model that measures how each variable affects that metric.

The model is then used to predict Hydro One's "expected" (benchmarked) costs, using the estimated relationship between the costs and the explanatory variables and Hydro One's values for the variables. The benchmark costs represent the costs that the model would expect a utility to have based on the actual operating conditions faced by that utility in that year.

The benchmark score is defined as the logarithmic percentage difference of the actual costs to the benchmark costs for a given year, as shown below.[20]

$$Benchmark\ Score = \text{Natural Log}\ \left(\frac{Historic\ or\ Projected\ Costs}{Benchmark\ Costs}\right)$$

The general approach of our benchmarking analysis is as follows:

1. Clearspring assembled the historical variables and costs of all utilities in the dataset.
2. Using the historical data, Clearspring estimated an econometric model that expresses the relationship between the variables and cost.
3. Using this model, Clearspring can then produce "benchmark" values for a given utility in each year. 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 a utility with the same variable values as Hydro One.
4. We then compare the total costs that are expected by the model to Hydro One's actual historical and projected costs in each year, which allows us to: (1) evaluate the historical and projected cost performance, and (2) recommend a stretch factor.

For a more detailed description of the methodology, please see Appendix A.

2.1 Prior Methodological Differences Addressed

As discussed in the Executive Summary, Clearspring has reviewed the methodological issues raised in past CIR applications that have included econometric benchmarking. While PEG and Clearspring follow much of the same best practice research methods, some research differences have surfaced in past proceedings. While these differences are relatively few, we continued to narrow these differences in areas that do not compromise the research.

The following list summarizes past differences and the approach Clearspring has taken to address them.

- Sample Period: In the current research, Clearspring has a consistent sample period for both the transmission and distribution datasets; the sample period for each dataset begins in 2000 and

[20] We use the logarithmic percentage difference rather than the arithmetic percentage difference, because this is convention within the benchmarking profession, including in 4GIR and all other CIR applications we and PEG have been involved in. The approach provides a more intuitive result when averaging increases and decreases over time.

ends in 2019 (20 years).[21] In the last Hydro One transmission application, Mr. Fenrick used a sample period of 2004 to 2016 (13 years). In PEG's responding report, PEG used a sample period of 1995 to 2016 (22 years).

In the latest Hydro Ottawa distribution application, there was agreement on the sample period between the consultants. Clearspring put forth a sample period of 2002 to 2017 (16 years) and PEG put forth this same sample period. We also note that in PEG's latest transmission benchmarking research in Quebec, they used a sample period that began in 2004 and ended in 2019 (16 years).[22]

Mr. Fenrick had concerns regarding PEG beginning the sample in 1995 in the last transmission application because of the transmission industry structural change that began in the late 1990s with the creation of independent system operations ("ISOs") and far lower cost challenges in those earlier years relative to recent years that unduly influenced the benchmark scores of all utilities in the sample for recent or forecasted years.[23] The 1990s had considerably different and lower cost challenges than those now faced by transmission utilities; current challenges include cybersecurity, reliability enhancements and NERC requirements, distributed energy resource connections, and geomagnetic disturbances. These current cost challenges either did not exist or had far lower cost ramifications in the 1990s than now. Therefore, a sample that does not include and is not influenced by these systemically dissimilar observations from the 1990s provides a more accurate model and result when benchmarking 2023 to 2027 CIR cost projections.

For this current research, Clearspring is of the opinion that a sample period that begins in 2000 for both the transmission and distribution datasets strikes the right balance between these considerations. Starting in 2000 for both studies provides consistency in the studies and addresses PEG's desire for a somewhat longer sample period and our preference to begin the sample period after the transmission industry's restructuring and the markedly different cost challenges found in the 1990s.

- Estimation Procedure: Clearspring is using the same estimation procedure that we used in the last Hydro One transmission research and the previous Hydro Ottawa distribution research. This procedure is known as the Driscoll-Kraay ("DK") method, which uses the ordinary least squares ("OLS") coefficients and then adjusts the standard errors due to heteroscedasticity and

[21] This is for the U.S. sample. Hydro One has data beginning in 2003 and going through 2027, with future years using the proposed spending amounts.

[22] Please see p. 77 of PEG's report, "Transmission Productivity and Benchmarking Study," conducted in Hydro-Quebec Transmission's proceeding R-4058-2018 Phase 2, February 15, 2021.

[23] Please see the PSE Reply Report in EB-2019-0082 authored by Mr. Fenrick, "Reply to PEG's Report (Incentive Regulation for Hydro One Transmission)," October 15, 2019.

autocorrelation.[24] PEG had some questions regarding the DK method in those two applications. PEG used a generalized least squares ("GLS") estimation method in both of those applications; however, the GLS method appeared unstable when applied to Hydro One's transmission operations, given the large difference in benchmark results based on the exact GLS method used by PEG.[25]

In PEG's latest transmission benchmarking research conducted this year in Quebec, PEG states that they have adopted Clearspring's estimation approach and decided to use the OLS coefficients and then adjust the standard errors.[26] This appears to be the same (or very similar) estimation approach as the DK method that we use. PEG states in their Quebec report:

> The choice between these approaches has been debated several times in recent Ontario Energy Board proceedings. To diffuse controversy in this proceeding, we have adopted in this study the general approach that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors available in the Stata statistical software package.

We support PEG on this effort to diffuse controversy on this methodological issue. This agreement on estimation approach will eliminate a major point of research difference between the consultants.

- Model Specification: Model specification is the process of determining which variables to include within the econometric models. There has been an evolution in these proceedings that has resulted in an improvement of the model specification as new or improved variables are developed and vetted.

  Regarding the distribution model specification, we reviewed the latest model specifications put forth by us and PEG in the Hydro Ottawa, Toronto Hydro, and last Hydro One distribution CIR applications. Hydro Ottawa's was the most recent. In the Hydro Ottawa proceeding, we put forth a model that PEG then modified in their responding report. Overall, PEG's modifications to our model specification we considered to be minor adjustments and the model specification is, in large part, similar to the one we put forth. This is especially true when applied to a non-urban

[24] Please see, Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[25] Please see the PSE Reply Report in EB-2019-0082 authored by Mr. Fenrick, "Reply to PEG's Report (Incentive Regulation for Hydro One Transmission)". October 15, 2019.

[26] Please see p. 101 of PEG's report, "Transmission Productivity and Benchmarking Study," conducted in Hydro-Quebec Transmission's proceeding R-4058-2018 Phase 2, February 15, 2021.

utility like Hydro One, since one of the variables eliminated by PEG was a quadratic on the "congested urban" variable.[27]

Considering the preceding statements and to reduce differences, we have adopted PEG's distribution total cost model specification found in Hydro Ottawa's application.[28] We have added one new variable without any further model specification modifications. This variable is a measure of how much extra work a distribution utility is doing on voltage levels that some utilities may classify as transmission voltages.[29] This approach builds upon the prior research and improves the benchmarking research.

Regarding the transmission model specification, we have built upon the prior Hydro One transmission proceeding. The model specification changes we made to our model in that past proceeding include taking out the construction standards index variable, including a new ISO binary variable, and substituting the "transmission substation capacity" variable for a "number of transmission substations" variable.

The construction standards index variable that Mr. Fenrick put forth in the last application was a complex variable and was met with some criticism. This is cited on page 30 in the OEB's Decision in that proceeding. Given that this variable has not been vetted in multiple proceedings (unlike the urban core variable for the distribution model), its complexity, and questions that accompanied its first introduction, we have not included this variable in our transmission model specification.[30]

A new ISO variable has been added to the transmission model specification. In the last transmission proceeding, considerable discussion centered on the fact that the transmission industry restructured in the late 1990s by forming ISOs and RTOs. PEG excluded some cost categories based on this structural change within the industry. Mr. Fenrick began his sample period after a large portion of this structural change occurred. Starting the sample in 1995 created a noticeable influence in the results of later and forecasted observations in PEG's analysis, due

[27] Both PEG and Clearspring included the congested urban variable; our only difference was on whether to include the quadratic of that variable.

[28] PEG's distribution total cost model put forth in Hydro Ottawa's application (EB-2019-0261) can be found on p. 49 of their report titled, "Custom Incentive Rate Mechanism Design for Hydro Ottawa", June 19, 2020.

[29] This distribution work variable helps adjust for the different definitions of transmission versus distribution that utilities may have. If a transmission utility has a large portion of its line voltages below 50 kV, it is presumably lowering the costs of the distribution utility (which would otherwise need to make those investments). Including this variable allows the model to adjust for the transmission and distribution classification differences between utilities. We used the 50 kV cut-off since this is the defined cut-off in Ontario for high and low voltage.

[30] We would anticipate that including this variable would be beneficial to the benchmark score of Hydro One.

partly to this structural change.[31] Given all this, we believe the best approach is to include an explanatory variable into the model specification that allows the model to estimate the cost impacts of utilities operating within ISOs or RTOs and begin the sample period after a sizeable portion of this industry restructuring occurred.

The final modification from the prior model specification for the transmission total cost model is using the "number of transmission substations" variable instead of the "transmission substation capacity" variable. This change is due to the substation capacity variable coming in with the correct sign but statistically insignificant, whereas the number of transmission substations variable does come in correctly signed and statistically significant at a 90% confidence level.

- Hydro One Distribution Service Area: The variable value used for Hydro One's service area was discussed and mentioned in the OEB's Decision in Hydro One's last distribution application.[32] While the measured service area for the rest of the sample is the full licensed service area for each utility (including unserved areas), we recognize that Hydro One is unique in that it has a sizeable area that is not currently served. In recognition of this and to reduce research differences, Clearspring has adopted the variable value for Hydro One that PEG used in its Hydro Ottawa research. This variable value is substantially reduced relative to the variable value used by our team in the last Hydro One distribution proceeding.[33]

- Peak Demand Variable Definition: In the last transmission proceeding for Hydro One, PEG used a different data source for peak demands than our team did. PEG used system peak demands and we used transmission peak demand (both are data elements reported on the FERC Form 1 for U.S. utilities). There are advantages and disadvantages of using either one of these data sources; the primary advantage of using the system peak demand data is that the data series begins prior to 2004, whereas the transmission peak data does not. Since Clearspring's sample now begins in 2000, we have decided to use the system peak demand data in the current research.

  Another previous question has been the calculation of the peak demand variable for both the transmission and distribution studies. In past proceedings, we have used a peak demand definition that takes the maximum peak demand value up until that observation year as the variable value. This was called a "maximum peak demand" or "ratcheted peak demand" variable. The use of this definition became a concern of ours when PEG used a sample period starting in 1995, because Ontario utility data begins, generally, in 2002. Further, some intervenors had brought up the fact that the variable value, by definition, can never decrease, even if peak

[31] Other differences between the 1990s and current conditions also led to a model having worse scores for all utilities in later years if it included these earlier periods. Realities that are present today, such as cybersecurity, geomagnetic protections, distribution energy resources, environmental regulations, and enhanced reliability, were either not present, or far less costly, in the prior century than they are today.

[32] EB-2017-0049, Board Decision, p. 29.

[33] The variable value for Hydro One has been changed from 961,498 to 651,974 square kilometres.

demands decrease over time. We would also add that since we are benchmarking forecasted costs through 2027, the peak demand variable for Hydro One's 2021 to 2027 value is a forecasted one. By nature, forecasts represent what is expected and do not reflect non-normal weather. However, actual weather, and thus realized peak demands, vary considerably from year to year from their weather normalized values. Over several years, some years are likely to be extreme and other years are likely to be mild, and thus peak demand values will fluctuate around the forecasted expectation. Since we are using the forecasted values for the future years, these years are at their normal levels and not likely to produce a new maximum peak demand value.

Considering these issues, we have used a 10-year rolling average of annual peak demands for the peak demand variable definition for both the transmission and distribution studies. This resolves the question of some utilities having more years available in the sample than others. It also addresses the question about the variable never being able to decrease (with a 10-year rolling average, it now can). Lastly, basing the variable on an average eliminates the problem of benchmarking future years using forecasts that are forecasted based on normal weather assumptions.

- Capital Asset Price Levels: In the last Hydro One transmission application, PEG raised an issue about using city of Toronto data as the basis for determining the capital asset price levels of Hydro One. In that application we used the headquarter cities for all the price levels for the entire sample, including Hydro One.[34]

  The year that the capital asset price level is determined has also been a point of concern of ours regarding PEG's research. Clearspring is of the opinion that a recent year should be used to determine the asset price levels, since most of the focus from stakeholders is regarding the results for the recent and forecasted years. Using a recent year to determine the price levels between utilities also helps to mitigate differences in the asset price inflation indices chosen by the consultants.

  We have addressed these issues by using 2015 asset price level data and then weighting it based on population weights for the 3-digit zip codes of each U.S. utility in the sample. For Hydro One, we population-weighted all the Ontario cities available in the 2016 RSMeans Heavy Construction Cost Data book.[35] This population-weighting shifts the asset price levels of each utility from being based on the headquarter city to one that is based on the service territory of the utility. Using more recent 2015 data should help to mitigate any inflation assumption differences in the asset price used by either PEG or Clearspring. However, we have addressed the inflation assumption differences as well (see the next point).

[34] See PEG's report in EB-2019-0082, p. 24.

[35] We use the 2016 RSMeans publication and apply the values in 2015 since that is when the published data was gathered.

- Canadian Input Price Inflation for Hydro One: Regarding the capital asset price inflation assumption for Hydro One that escalates the asset price levels for inflation, we have adopted the compromise approach put forth by PEG in Hydro Ottawa's last application. In that application, PEG chose to give a 50% weight to our preferred index (the U.S. Handy-Whitman indices that are specific to transmission or distribution construction cost inflation) and a 50% weight to PEG's preferred index (the Canadian implicit capital stock price index for utilities; this index is specific to Canada).

  For the OM&A input prices, we have used the Canadian components of the Ontario average weekly earnings for the labour component and the Canadian GDP-IPI for the non-labour component. This assumption will have a negligible impact on the results, and while we generally continue to prefer using the same inflation indices for Hydro One as used for the rest of the sample, we do recognize the advantage of using Canadian indices and applying those to a Canadian utility. To reduce research methodology differences between Clearspring and PEG, combined with the negligible impact on the study, we have therefore applied the method of using the Canadian inflation measures and applying those to Hydro One.

- Transmission Depreciation Rate: In the last Hydro One transmission proceeding, PEG made the transmission depreciation rate approach a bit more detailed than the approach we took at the time. We used the Bureau of Economic Analysis (BEA) assumptions for electrical transmission, distribution, and industrial equipment as the basis for the depreciation rate assumption. This resulted in a transmission depreciation rate of 3.59%. PEG added the BEA's assumptions for electrical light and power structures and weighted transmission plant and general plant using cost share weights. All told, PEG's calculations led to a transmission depreciation rate assumption of 3.30%. We agree that PEG's approach is more detailed, and we use this 3.30% assumption in the current transmission research.[36]

- Older Capital Benchmark Year: The capital stock and cost calculations that are used by both Clearspring and PEG depend upon building up capital quantities and costs using the historical plant addition data for each utility. This method is called the perpetual inventory capital method.[37] PEG and Clearspring also apply a geometric decay assumption that uses a depreciation rate to depreciate historical capital additions in each year (see the prior point for the transmission depreciation rate assumption). In other incentive regulation proceedings, both inside and outside of Ontario, these capital quantity and costing assumptions can generate considerable debates, as some consultants make different assumptions on capital which can have large impacts on the

[36] For the distribution depreciation rate, we continue to use the 4.59% depreciation rate assumption that is used in all the CIR distribution applications submitted by our team and PEG.

[37] In Appendix A we provide more details on the perpetual inventory method, including the equations used.

study results. In our opinion, geometric decay is the proper assumption to use; it aligns best with theory and the realities of how a basket of utility assets depreciates over time for a utility.

Despite our agreement on that major issue, there have been a few minor differences regarding the treatment of capital that have been brought forth in past CIR proceedings. Our approach in the present application represents a compromise on the asset price levels, inflation, and depreciation rate assumptions (see prior discussion). The remaining difference is that the starting year that we have used for the perpetual inventory method for the U.S. sample has been 1989 in our prior research, whereas in a few past proceedings PEG has used a 1964 start year. This start year is called the "capital benchmark year". The capital benchmark year begins the perpetual inventory calculation in that start year, and then the capital stock is depreciated in subsequent years and plant additions are added to the capital stock to build the capital quantities and costs consistently over time for the entire sample.

The earlier the capital benchmark year is, the more actual plant addition data can be used to calculate the capital quantity and costs of each utility. Given the fact that PEG and Clearspring assume geometric decay, much of the capital quantity assumed in the capital benchmark year will have depreciated by the relevant years in the study. Despite our continued opinion that the capital benchmark year is a minor issue and that 1989 was a sufficient capital benchmark year, we have nonetheless collected all the necessary data to begin the capital benchmark year in 1947 for most of the U.S. utilities, and in 1959 for the rest that were missing data between 1947 and 1959.[38] We have therefore used the actual transmission or distribution plant addition data for the U.S. sample for the years 1948 to 2019 in the perpetual inventory capital method to calculate capital quantities and costs. This is over 70 years' worth of actual plant addition data.

- Customized labour and non-labour OM&A weights: For the OM&A input price index, an assumption as to the weights to use, between labour and non-labour, is required. In the 4GIR research conducted by PEG, a 70% labour and 30% non-labour assumption was used for the entire Ontario sample. In Mr. Fenrick's past CIR research, he has continued this 4GIR assumption of a 70/30 weight for all the sampled utilities. This enables consistent treatment between a U.S. sample and Ontario utilities, since Ontario utilities do not report labour/non-labour OM&A breakdowns. PEG has responded in past proceedings by saying that salary and wage data, while not publicly available for Ontario utilities, is available for the U.S. sample and should be used for the U.S. observations.

[38] In the data for 1947, the total utility net plant data is available but not the breakdowns for transmission or distribution net plant. However, breakdowns for gross plant in service are available. Therefore, we took the proportion of transmission gross plant in service to total gross plant in service to estimate the transmission net plant in service. We did the same for the distribution calculation. Any possible inaccuracy in this calculation will be miniscule by the time we consider the sampled years of the study and starting in 1947 allows us to use the actual plant additions for transmission and distribution in all years after 1947.

Modifying this treatment and assumption will have a negligible impact on the results and Hydro One was able to provide us with an estimate of Hydro One's labour/non-labour breakdown to be consistent with the U.S. sample. We have gathered the salaries and wages for the U.S. sample, located on the FERC Form 1s and requested Hydro One to estimate the labour and non-labour components within their OM&A expenses. We have used this estimate, along with the salary and wages data for the U.S. sample, to customize the labour and non-labour weights and to calculate the OM&A input prices for each sampled utility.

- Pensions and Benefits Treatment: Including or excluding pensions and benefits has been a topic of discussion in several CIR proceedings. Driving the issue is that Ontario distributors do not consistently report OM&A pensions and benefits expenses. Further, the different health care and other regulatory differences between the U.S. and Ontario can cause pensions and benefits to be higher in the U.S. than in Ontario, creating a small bias in favor of Ontario utilities when they are included. We believe it is fair to say that both consultants would prefer to exclude these expenses when it is possible to consistently do so. In the current research, we requested that Hydro One provide Clearspring with their OM&A pensions and benefits estimates for each year for transmission and distribution. This enabled us to exclude these expenses from both the U.S. sample and Hydro One.

2.2 Output and Business Condition Variables

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 regional input prices, lengths of line, highly congested urban areas, forestation, etc. Details of the output variables and business condition variables used for the transmission and distribution benchmark studies are described in Appendix A.

2.3 Benchmarks for Future Years

The same econometric model and its associated parameter values that are estimated using historical data (and used to develop Hydro One's historical benchmarks) are also used to calculate the Company's benchmarks for the forecasted years through 2027. These parameter values are combined with projected variable values to calculate the expected total costs of Hydro One in the future years of the Custom IR period.

Clearspring was provided OM&A expense, plant addition, physical asset, customer count, and peak demand projections from Hydro One. We used these projections to calculate variables for each future year, and then inserted these variable projections into the estimated econometric model.

2.4 Other Model Details

Other model details are provided in Appendix A. These details include the method used to calculate capital quantities and costs (perpetual inventory method), model estimation approach, model specification, and variable parameter hypothesis testing.

3 Transmission Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's transmission costs. This study provides a comparison of Hydro One's actual and projected transmission total costs to the model-calculated benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within.

3.1 Transmission Variables

The two output variables used in the transmission benchmarking research are:

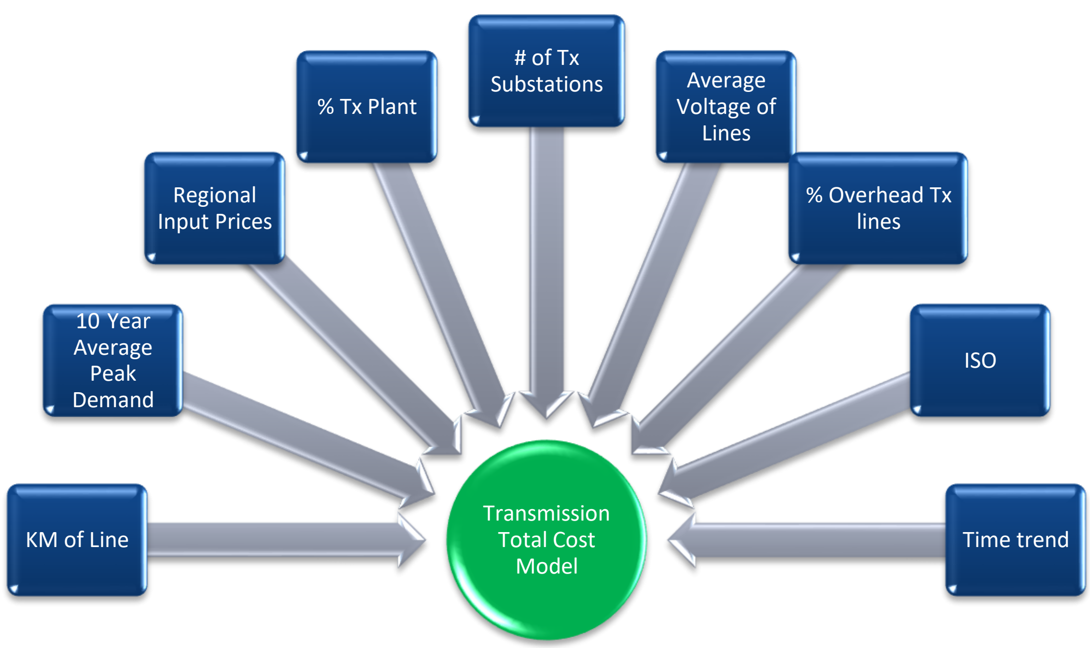
- Total kilometres of transmission line, and
- A 10-year rolling average of peak demand.

The business condition variables used in the transmission benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission plant in total electric utility plant,
- Number of transmission substations,
- Average voltage of transmission lines,
- Percent of transmission lines that are overhead,
- Independent System Operator (a binary value), and
- A time trend variable.

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

Figure 6 Variables in Transmission Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All first order 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).

3.1.1 The Definition of Transmission Costs

Transmission OM&A and capital costs used in the benchmarking models for the U.S. transmission utilities are derived using FERC Form 1 filing data.[39] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding plant in service additions that are used in constructing capital costs.[40]

Clearspring 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 transmission 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 removed, would yield an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. Clearspring also subtracted pensions and benefit expenses from the cost definition for both the U.S. and 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).[41] 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, regional market expenses, 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.

3.1.2 Transmission Output Variables

The transmission total cost model includes two output variables. The first is the total kilometres of transmission line, the second is the ten-year rolling average of peak demand for each utility. The output variables are gathered from FERC Form 1 data. The historical output data for Hydro One comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average

[39] Some of the FERC Form 1 data was gathered using SNL Energy's database tool.

[40] Clearspring gathered plant addition data going back to 1947 for this study. Older data was collected from various EIA annual reports.

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

of annual peak demand on the system in the sample that has occurred up to that observation's year. For years without ten years' worth of historical data, the years that are available are averaged.[42]

3.1.3 Transmission Business Condition Variables

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

The **percentage of transmission plant in total electric plant** uses gross plant in service information from FERC Form 1s. 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 **number of transmission substations** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to Clearspring by Hydro One. We would expect a positive correlation between the number of transmission substations and 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 positive coefficient.

The **percentage of overhead lines** measures the percentage of overhead transmission lines to total transmission lines. Constructing underground transmission lines is costlier than constructing overhead transmission lines. As the percentage of overhead lines decreases, we would expect total costs to increase since this implies a higher percentage of lines that are underground. This implies a negative coefficient value is expected from this variable.

The **Independent System Operator (ISO)** variable indicates if the utility was operating under an ISO or Regional Transmission Operator (RTO) in the observed year. This variable is a binary variable that will equal "1" if in the observed year the utility is in an ISO or RTO and will equal "0" if this is not the case. We do not have an a priori expectation of the variable sign. While the ISO may take on some planning costs that the utility would have engaged in otherwise, the transmission utility may still be required to undertake some planning costs as well as added investments that the ISO may request to encourage a more efficient energy market. In the model, we find that the ISO parameter estimate is positive, indicating a positive relationship between being in an ISO and transmission total costs.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and econometric total cost benchmarking

[42] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding an additional year increases or decreases total costs.

The estimated coefficient value on the trend variable is positive in our research, which aligns with our TFP trend research that indicates the industry has experienced negative TFP trends during the sample period.

3.2 Transmission Sample

The transmission benchmarking sample is comprised of 59 U.S. utilities plus Hydro One. The benchmark sample period begins in 2000 and extends to 2019. The sample is of an unbalanced panel form which allows utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,160 U.S. utility observations in the sample. Including Hydro One there are 1,185 observations. This large number of observations enables robust parameter estimates and a strong statistical model. Note that this sample is also used for the TFP analysis with the exceptions noted with an asterisk.

The sample of utilities within the sample is provided in the following table.[43]

[43] Data shown for the sample is from the most recently available year for each utility. For most of the sample this is for the year 2019. For Hydro One, it is 2027.

Table 1 Transmission Benchmarking and TFP Sample

Transmission Benchmarking and TFP Sample

Company	10-Year Average Peak Demand	Tx Line Lengths (KM)	Company	10-Year Average Peak Demand	Tx Line Lengths (KM)
Alabama Power Company	11,578	17,307	Kansas Gas and Electric Company	2,445	4,250
ALLETE (Minnesota Power)*	1,586	4,608	Kentucky Utilities Company	4,488	6,537
Appalachian Power Company	7,517	10,449	Louisville Gas and Electric Company	2,627	1,475
Arizona Public Service Company	7,159	10,106	MDU Resources Group, Inc.	568	5,446
Atlantic City Electric Company*	2,651	2,210	Mississippi Power Company	2,588	3,589
Avista Corporation	1,668	3,610	Monongahela Power Company	2,002	3,613
Baltimore Gas and Electric Company*	6,767	1,490	Nevada Power Company	5,781	3,060
Black Hills Power, Inc.	430	1,244	New York State Electric & Gas Corporation	2,947	7,317
Central Hudson Gas & Electric Corporation	1,129	964	Niagara Mohawk Power Corporation	5,960	17,611
Central Maine Power Company	1,586	4,677	Northern States Power Company - MN	7,604	9,239
Cleco Power LLC	2,471	2,204	Oklahoma Gas and Electric Company	6,657	9,665
Commonwealth Edison Company	21,525	8,015	Orange and Rockland Utilities, Inc.	1,401	889
Consolidated Edison Company of New York	5,070	837	PacifiCorp	10,148	28,350
Duke Energy Carolinas, LLC	17,526	13,329	PECO Energy Company	8,491	2,041
Duke Energy Florida, LLC	9,706	8,354	Potomac Electric Power Company	6,134	1,285
Duke Energy Indiana, LLC	5,885	8,548	PPL Electric Utilities Corporation	7,440	7,244
Duke Energy Progress, LLC	13,171	10,082	Public Service Company of Colorado	6,519	7,721
Duquesne Light Company	2,834	1,075	Public Service Company of New Hampshire	1,641	1,675
El Paso Electric Company	1,804	2,976	Public Service Company of Oklahoma	4,152	5,026
Empire District Electric Company	1,144	2,287	Public Service Electric and Gas Company	10,079	3,237
Entergy Arkansas, Inc.	5,402	8,350	Rochester Gas and Electric Corporation	1,594	1,761
Entergy Mississippi, Inc.*	3,134	5,041	San Diego Gas & Electric Co.	4,530	3,402
Entergy New Orleans, Inc.*	1,071	266	South Carolina Electric & Gas Co.*	4,776	5,915
Florida Power & Light Company	22,956	11,713	Southern California Edison Company	22,502	23,378
Gulf Power Company	2,521	2,739	Southern Indiana Gas and Electric Company	1,224	1,654
Hydro One Networks*	**21,830**	**20,788**	Southwestern Public Service Company*	4,821	12,473
Idaho Power Co.*	3,250	7,692	Tampa Electric Company	3,865	2,164
Indianapolis Power & Light Company	2,853	1,390	Tucson Electric Power Company	2,489	3,523
Jersey Central Power & Light Company*	6,079	4,181	Union Electric Company	7,716	4,115
Kansas City Power & Light Company	3,511	2,919	West Penn Power Company	3,941	3,510

* n Benchmark Sample but not TFP Sample

3.2.1 The Necessary Data is Not Available for Other Large Canadian Utilities

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. Therefore, the only way to include these utilities in the sample is to directly request it from each utility and have them provide all the necessary information for the study.

Hydro One contacted several 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 Clearspring the type of cost and variable information that was used in this report. None of the utilities chose to participate. Due to the absence of publicly available Canadian data, lack of voluntary participation on the part of utilities, and non-uniformity of cost categories in Canada even if the data were available, Clearspring has not used Canadian utilities in its dataset, other than Hydro One. This aligns with the prior transmission studies produced by our team and PEG which both used a sample comprised of U.S. utilities.

3.3 Transmission Model

The parameter estimates from the transmission total cost model are presented in the following table.

Table 2 Total Cost Model Estimates (Transmission)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	10.6328	0.1407	75.5600	0.0000
KM of Transmission Lines (KM)	0.2929	0.0094	31.0000	0.0000
Peak Demand (D)	0.6475	0.0137	47.4000	0.0000
KM*KM	0.0204	0.0061	3.3600	0.0020
D*D	0.1111	0.0056	19.7600	0.0000
KM*D	-0.0098	0.0195	-0.5000	0.6200
% Tx Plant	0.3731	0.0414	9.0100	0.0000
# of Subs	0.0634	0.0074	8.5400	0.0000
Average Line Voltage	0.3465	0.0263	13.1800	0.0000
% Overhead	-1.3965	0.0570	-24.5100	0.0000
ISO	0.1216	0.0109	11.1300	0.0000
Trend	0.0075	0.0024	3.0800	0.0050

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.942.

3.4 Transmission Results

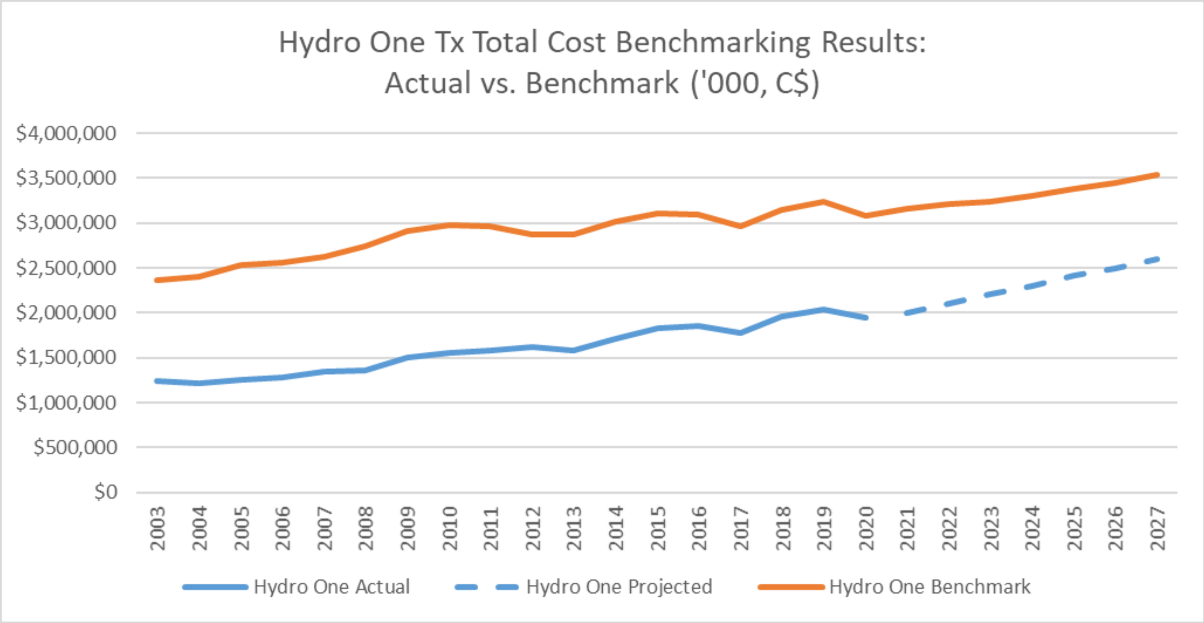
The following table breaks down the historical and forecast benchmark scores from 2003 through 2027. We note that the benchmark scores for future years assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 3 2003-2027 Transmission Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2003	-64.8%
2004	-67.9%
2005	-70.3%
2006	-69.9%
2007	-67.1%
2008	-69.6%
2009	-66.1%
2010	-64.7%
2011	-62.8%
2012	-57.8%
2013	-59.6%
2014	-56.9%
2015	-52.9%
2016	-51.0%
2017	-50.8%
2018	-47.3%
2019	-46.3%
2020	-46.1%
2018-2020 average score	**-46.6%**
2021	-45.5%
2022	-42.5%
2023	-38.4%
2024	-36.6%
2025	-33.9%
2026	-32.6%
2027	-30.9%
2023-2027 average score	**-34.5%**

The following graph displays how Hydro One's actual and projected transmission total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 7 Hydro One Transmission Total Cost Actual vs. Benchmark



Hydro One's ranking among the transmission benchmarking sample substantiates this total cost performance benchmark score. Each utility in the sample received a transmission cost performance score; for every utility except Hydro One, the score was based on that utility's transmission costs in the most recent three years where data was available (compared to the model's expected costs for that utility in those years). For Hydro One, the score was based on the average of the CIR years of 2023 to 2027 proposed costs (compared to the model's expected costs for Hydro One in those years).[44] Hydro One's benchmark score ranks well in the top quartile.[45] The Company ranks 2nd out of the 60 utilities in the full transmission benchmarking sample.[46] Hydro One's position is noted in the green bar.

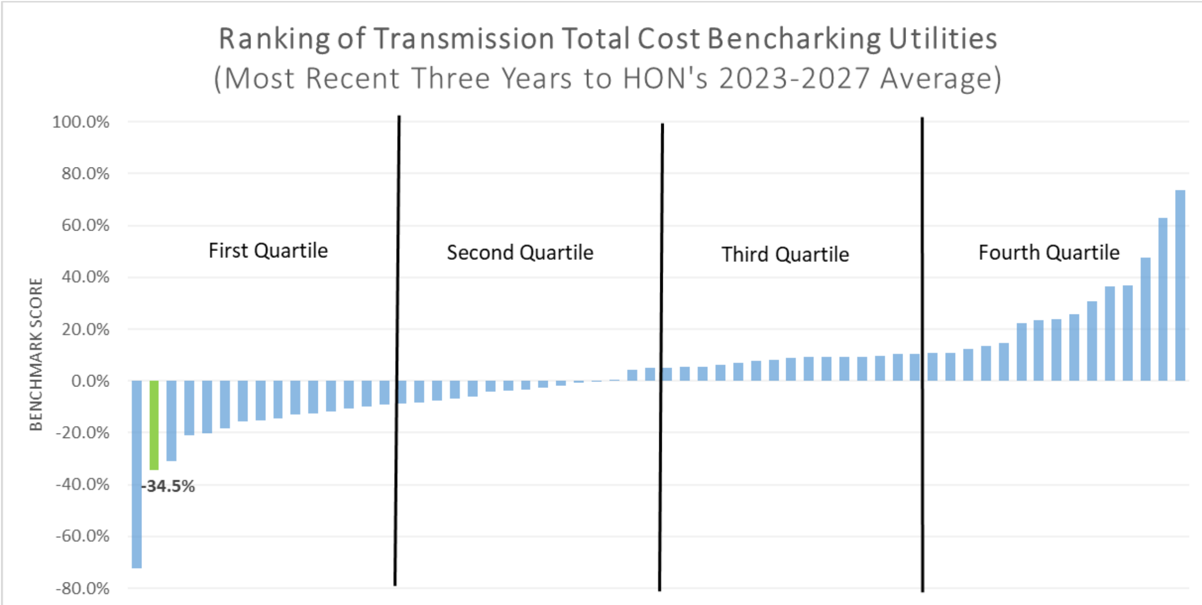
---

[44] If we instead ranked Hydro One's 2017 to 2019 cost performance relative to the sample's 2017 to 2019 cost performance, the Company would still rank 2nd among the entire sample.

[45] The most recent three years for the sample are 2017 to 2019 for most of the utilities. Hydro One's benchmark score is the average of 2023 to 2027.

[46] There are 59 U.S. transmission utilities in the sample; with Hydro One added, the full sample comprises 60 utilities.

Figure 8 Ranking of Utilities by Transmission Total Cost Scores



As noted, Hydro One's transmission total cost benchmarking scores indicate the Company's transmission costs have been significantly below benchmark expectations both historically and through the CIR period. We would expect a company who has a benchmark score as strong as Hydro One's historical score to eventually converge towards the mean of the sample. While Hydro One's score during the CIR period does moderate some, its overall ranking remains second throughout the CIR period and its benchmark score remains significantly below cost expectations. Further, Hydro One is not significantly lowering its overall capital age during the CIR period despite having relatively old assets. The research and CIR proposal indicates the Company can manage its assets at an older age than its industry peers.

4 Distribution Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's distribution costs. This study provides a comparison of Hydro One's distribution total costs to the benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within. These comparisons are made for both historical and forecasted years through 2027. For more information on the benchmarking methods please see Chapter 2 and Appendix A.

4.1 Distribution Variables

The three output variables used in the distribution benchmarking research are:

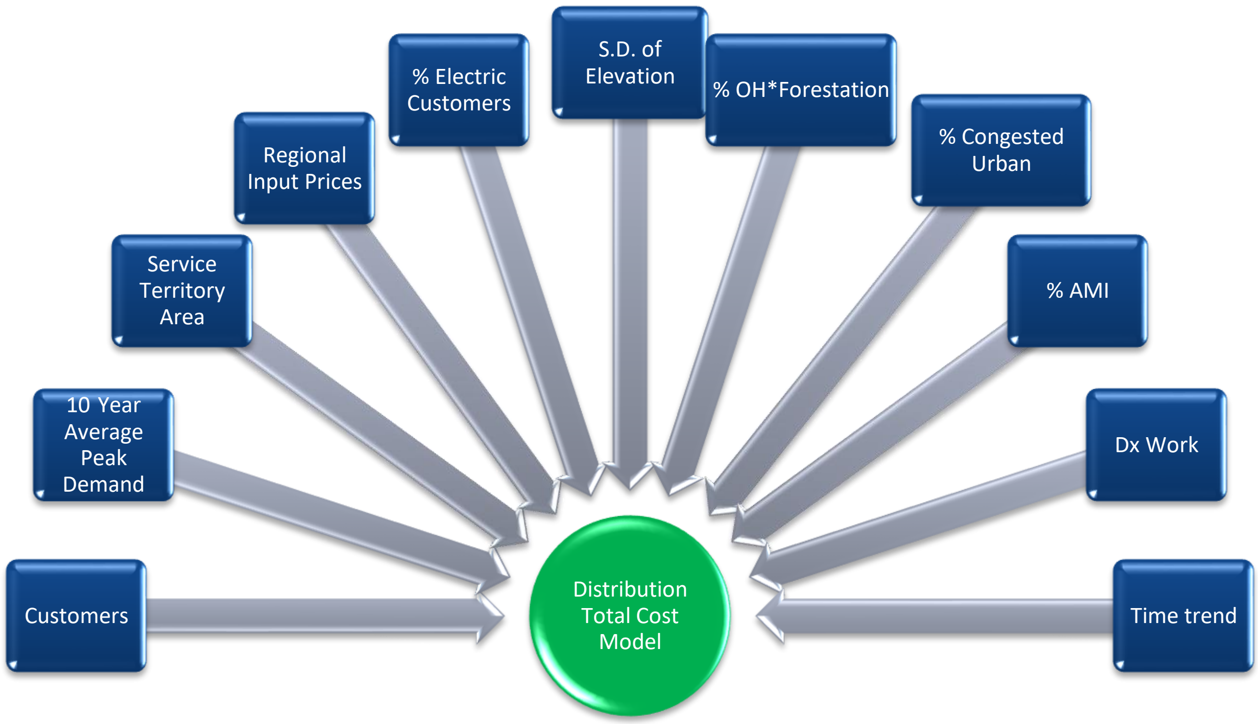
- Total customers served,
- A 10-year rolling average of peak demand, and
- The total distribution service territory of the utility.

The business condition variables used in the distribution benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of electric customers in the total of electric and gas customers,
- Standard deviation of elevation,
- Percent of distribution plant that is overhead multiplied by the percent of forestation,
- Percent of congested urban area within each utility's service territory,
- Percent of AMI (smart meters) deployed by the utility in each year,
- The distribution work variable measures the percent of transmission lines classified as being served by transmission that are above 50 kV, and
- A time trend variable.

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

Figure 9 Variables in Distribution Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by distribution utilities. All first order 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).

4.1.1 The Definition of Distribution Costs

OM&A and capital costs used in the benchmarking models for the U.S. distribution utilities are derived using FERC Form 1 filing data.[47] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding "plant in service" and accumulated depreciation that are used in constructing capital costs.[48]

We used a cost definition that is consistent between both the U.S. and Hydro One in the sample. The cost definition is the same as the latest one used in the Hydro Ottawa total cost benchmarking study led by

[47] Some of the FERC Form 1 data was gathered using SNL Energy's database tool.

[48] Clearspring gathered plant addition data going back to 1947 for this study. This data was collected from various EIA annual reports.

Mr. Fenrick, with the exception that we excluded pensions and benefits.[49] Clearspring began with the benchmark-based cost definition used by PEG in the 4GIR proceeding. To be consistent with the U.S. sample, we then added high-voltage expenses to the cost definition for Hydro One. The FERC Form 1 does not break down high- versus low-voltage distribution expenses, as Ontario reporting does. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from Hydro One's cost definition, due to those expenses not being included in the U.S. Form 1 data. Bad debt expenses (called uncollectible expenses in the FERC Form 1) have been excluded for all utilities, to match the 4GIR benchmark-based definition.

The cost definition also excludes customer service and information ("CSI") expenses from total costs for all utilities. This is due to the possibility that the U.S. utilities include conservation demand management ("CDM") expenses in the CSI expense category. This assures cost consistency between the U.S. sample and Hydro One. The table below summarizes the cost definition treatment.

Table 4 Distribution Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	This is the starting point for the sample.
Contributions in Aid of Construction (CIAC)	We subtracted from Hydro One distributor costs, since U.S. cost data does not include CIAC.
High Voltage Expenses	We added to Hydro One costs, since U.S. cost data includes distribution high voltage costs.
Customer Service and Information (CSI) Expenses	We excluded CSI expenses for both the U.S. and Hydro One, given the possible inconsistency in CDM reporting.
Pensions and Benefits	We excluded OM&A pensions and benefits from both the U.S. and Hydro One data.

4.1.2 Distribution Output Variables

The distribution total cost model includes three output variables.[50] The first is the total number of customers served, the second is the ten-year rolling average of peak demand for each utility, and the third is the total service territory area for each utility. The first two output variables are gathered from FERC

[49] This is because we can exclude these expenses as Hydro One is the only non-U.S. utility in the sample and we can directly request this data. Given higher health care costs in the United States, we would expect that excluding pensions and benefits from the cost definition would worsen Hydro One's benchmark score.

[50] This three-output specification matches PEG's latest distribution total cost model specification found in the Hydro Ottawa proceeding.

Form 1 data. The third uses GIS information on the utility service territory area; this variable uses the same values for the U.S. sample as found in the Hydro Ottawa research by Clearspring and PEG.[51] The historical output data for Hydro One regarding the number of customers and peak demands comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average of annual peak demand on the system in the sample that has occurred up to that year. For years without ten years' worth of historical data, the years that are available were averaged.[52]

4.1.3 Distribution Business Condition Variables

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

The **percentage of electric customers** measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Hydro One since they do not serve natural gas customers. We would expect a positive parameter estimate on this variable.

The **standard deviation of elevation** variable is calculated based on geographic information system ("GIS") elevation topography maps. A higher standard deviation of the elevation indicates increased elevation changes and variance within the utility's service territory. We would expect that a service territory with more hills, mountains, and other elevation changes would be more challenging and costly to serve, *ceteris paribus*. Therefore, a positive parameter estimate is expected (indicating a positive correlation between standard deviation of elevation and costs).

The **overhead percentage times percentage of forestation** variable is based on the overhead plant in service for each utility (for the percent overhead) and GIS land cover maps (for percent forestation). These maps used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of overhead lines and forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities.

The **congested urban** variable measures the percentage of a utility's service territory that consists of a major urban load center that is "congested." Congested urban areas have physical constraints that necessitate complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Congested urban areas also often necessitate electrical equipment unique to such

[51] In the Hydro Ottawa research, Clearspring used a higher number for Hydro One's service area than PEG did. Clearspring used the value of the entire service area to match how the rest of the sample was calculated. PEG reduced this number substantially. We have used PEG's lower number to help reduce research differences and address one of the issues brought forth in the last Hydro One distribution proceeding.

[52] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

subterranean infrastructure. The variable measures the percentage of service territory classified as "congested urban" area.[53]

We expect a utility that has a congested urban area within its service territory would experience substantial incremental costs as compared to a utility that does not have such an area within its service territory. The parameter value for this variable is expected to be positive, indicating a positive correlation of percent congested urban with total costs.

The **percentage of smart meters** variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use ("TOU") electricity rates that can create efficiencies mainly in the realm of power supply. Since this study is focused on distribution total costs, we would expect a positive coefficient on the percent smart meter variable.

The **distribution work variable** measures the percentage of transmission lines that are classified as transmission and are above 50 kV. This helps adjust for utilities classifying transmission and distribution assets differently. Some transmission utilities own lines that are below 50 kV and others do not. If the transmission system is taking on costs and serving lines that otherwise would be classified as distribution, this will tend to decrease costs for the distributor in that region relative to its peers. Likewise, if the distribution system is serving lines that would sometimes be classified as transmission for other utilities, this will tend to increase distribution costs for that utility relative to its sample peers. We use the 50 kV cut-off because this is the line used in the RRR reporting in Ontario between high voltage and low voltage. We would expect a positive correlation between distribution total costs and the percentage of lines above 50 kV served by the transmission utility.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding an additional year increases or decreases total costs.

4.2 Distribution Sample

The distribution benchmarking sample is comprised of 81 U.S. utilities plus Hydro One.[54] The benchmark sample period begins in 2000 and extends to 2019. The sample is an unbalanced panel, which enables

---

[53] It is the same variable used in the most recent Toronto Hydro and Hydro Ottawa applications, with a few minor adjustments made in the Hydro Ottawa research. The variable is fully described in our Toronto Hydro report titled, "Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels". Our team, while at PSE, produced the report in EB-2018-0165. July 16, 2018.

[54] In Hydro One's prior distribution application, we included U.S. rural electric cooperatives in the benchmarking sample. However, to our knowledge, recent cooperative data is no longer being released publicly.

utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,572 U.S. utility observations in the sample. Including Hydro One there are 1,598 observations. This large number of observations enables robust parameter estimates and a strong statistical model.

The sample of utilities within the sample is provided in the following table.[55]

Table 5 Distribution Benchmarking Sample

Distribution Benchmarking Sample

Company	Number of Customers	Company	Number of Customers
Alabama Power Company	1,488,234	Madison Gas and Electric Company	156,833
ALLETE (Minnesota Power)	147,340	MDU Resources Group, Inc.	143,268
Appalachian Power Company	954,688	Metropolitan Edison Company	572,912
Arizona Public Service Company	1,260,115	Mississippi Power Company	188,342
Atlantic City Electric Company	558,559	Monongahela Power Company	391,968
Avista Corporation	390,059	Nevada Power Company	951,217
Baltimore Gas and Electric Company	1,299,421	New York State Electric & Gas Corporation	902,593
Black Hills Power, Inc.	73,084	Niagara Mohawk Power Corporation	1,396,454
Central Hudson Gas & Electric Corporation	258,977	Northern Indiana Public Service Company	473,221
Central Maine Power Company	639,993	Northern States Power Company - MN	1,491,047
Cleco Power LLC	287,921	Northern States Power Company - WI	261,093
Cleveland Electric Illuminating Company	752,471	Ohio Edison Company	1,052,921
Commonwealth Edison Company	4,048,298	Oklahoma Gas and Electric Company	854,128
Connecticut Light and Power Company	1,256,150	Orange and Rockland Utilities, Inc.	234,551
Consolidated Edison Company of New York	3,518,923	Pacific Gas and Electric Company	5,479,889
Consumers Energy Company	1,836,668	PacifiCorp	1,932,532
Delmarva Power & Light Company	529,284	PECO Energy Company	1,654,006
DTE Electric Company	2,208,925	Pennsylvania Electric Company	586,517
Duke Energy Carolinas, LLC	2,650,817	Pennsylvania Power Company	167,058
Duke Energy Florida, LLC	1,832,872	Portland General Electric Company	890,019
Duke Energy Indiana, LLC	840,116	Potomac Electric Power Company	889,380
Duke Energy Kentucky, Inc.	143,431	PPL Electric Utilities Corporation	1,450,006
Duke Energy Ohio, Inc.	722,911	Public Service Company of Colorado	1,499,395
Duke Energy Progress, LLC	1,590,969	Public Service Company of New Hampshire	520,866
Duquesne Light Company	600,804	Public Service Company of Oklahoma	557,421
El Paso Electric Company	429,191	Public Service Electric and Gas Company	2,285,737
Empire District Electric Company	174,520	Puget Sound Energy, Inc.	1,165,691
Entergy Arkansas, Inc.	713,080	San Diego Gas & Electric Co.	1,452,137
Entergy Mississippi, Inc.	450,377	South Carolina Electric & Gas Co.	739,385
Entergy New Orleans, Inc.	204,479	Southern California Edison Company	5,139,331
Florida Power & Light Company	5,061,510	Southern Indiana Gas and Electric Company	147,287
Gulf Power Company	464,882	Southwestern Public Service Company	394,669
Hydro One Networks	**1,420,879**	Tampa Electric Company	771,960
Idaho Power Co.	565,077	Toledo Edison Company	311,844
Indiana Michigan Power Company	596,731	Tucson Electric Power Company	428,626
Indianapolis Power & Light Company	507,576	Union Electric Company	1,230,246
Jersey Central Power & Light Company	1,138,696	Virginia Electric and Power Company	2,627,789
Kansas Gas and Electric Company	332,220	West Penn Power Company	727,552
Kentucky Power Company	165,461	Wisconsin Electric Power Company	1,138,054
Kentucky Utilities Company	556,129	Wisconsin Power and Light Company	476,494
Louisville Gas and Electric Company	415,853	Wisconsin Public Service Corporation	447,493

4.3 Distribution Model

The parameter estimates from the distribution total cost model are presented in the following table.

Table 6 Total Cost Model Estimates (Distribution)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	13.0653	0.0235	555.8200	0.0000
Customers (N)	0.6319	0.0192	32.8500	0.0000
Peak Demand (D)	0.3392	0.0216	15.6800	0.0000
Area (A)	0.0547	0.0025	21.5400	0.0000
N*N	0.8638	0.0697	12.4000	0.0000
D*D	1.0755	0.0710	15.1400	0.0000
A*A	0.0392	0.0030	13.2800	0.0000
N*D	-1.8973	0.1413	-13.4300	0.0000
N*A	0.1254	0.0179	7.0000	0.0000
D*A	-0.1627	0.0200	-8.1300	0.0000
% Electric	0.1966	0.0169	11.6500	0.0000
Standard Deviation of Elevation	0.0221	0.0025	8.8600	0.0000
% OH*% Forest	0.0601	0.0021	28.6600	0.0000
% Congested Urban	13.7795	0.9436	14.6000	0.0000
% AMI	0.0729	0.0083	8.7600	0.0000
Dx Work (% Tx Lines Above 50 kV)	0.1148	0.0138	8.2900	0.0000
Trend	-0.0041	0.0011	-3.7200	0.0010

[55] Data shown is from the most recently available year for each utility. For most of the sample this is for the year 2019. For Hydro One, it is 2027.

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.975.

4.4 Distribution Results

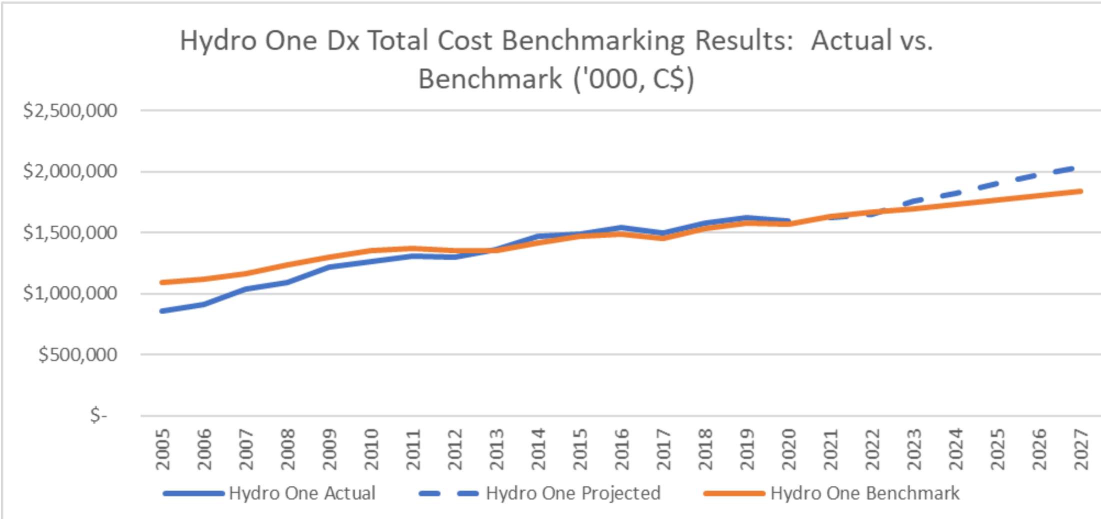
The following table breaks down the historical and forecast year benchmark and Company distribution total costs from 2005 through 2027. We note that the benchmark scores assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 7 2006-2027 Distribution Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2005	-24.4%
2006	-19.6%
2007	-11.3%
2008	-11.9%
2009	-7.0%
2010	-6.8%
2011	-4.7%
2012	-3.8%
2013	0.8%
2014	4.1%
2015	0.9%
2016	3.4%
2017	2.7%
2018	2.9%
2019	2.7%
2020	1.7%
2018-2020 average score	**2.5%**
2021	-0.6%
2022	-0.9%
2023	3.3%
2024	5.1%
2025	7.4%
2026	8.8%
2027	10.3%
2023-2027 average score	**7.0%**

The following graph displays how Hydro One's actual and projected distribution total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 10 Hydro One Distribution Total Cost: Actual vs. Benchmark

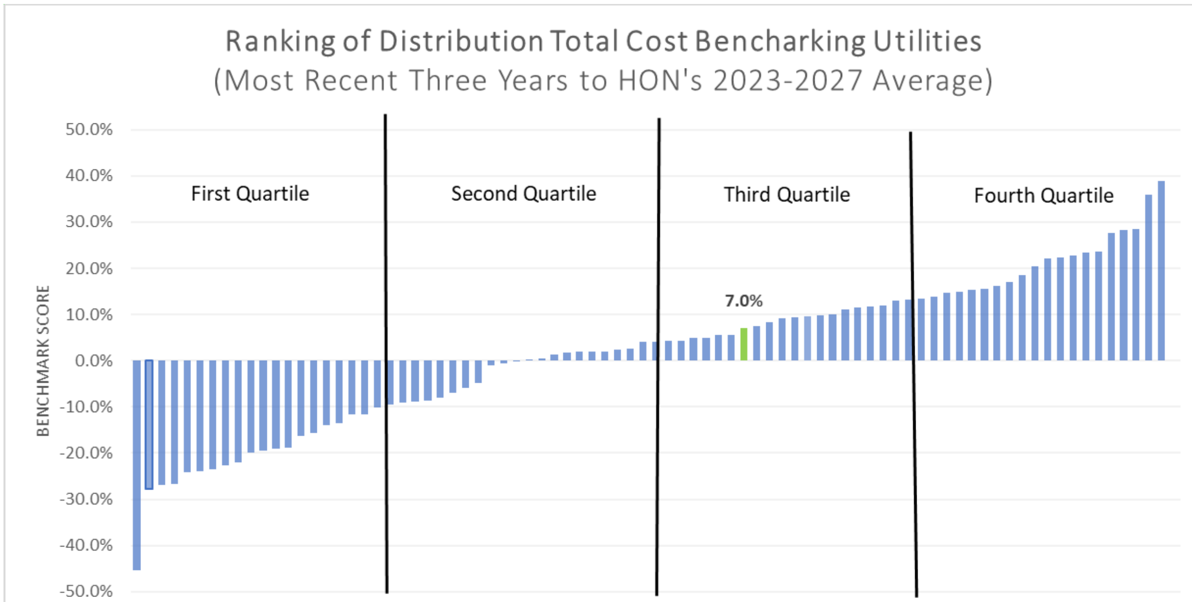


Hydro One's ranking among the benchmarking sample substantiates this total cost performance score. Clearspring ranked the distribution sample using the three-year distribution cost performance benchmarking score. Each utility in the sample received a distribution cost performance score; for every utility except Hydro One, the score was based on that utility's distribution costs in the most recent three years where data was available (compared to the model's expected costs). For Hydro One, the score was based on the average forecasted CIR costs from 2023 to 2027 (compared to the model's expected costs for those years). Hydro One ranks in the third quartile.[56] The Company ranks 49th out of the 82 utilities in the full sample.[57] Hydro One's position is noted with the green bar.

[56] The most recent three years for the sample are 2017 to 2019 for most of the utilities. This most recent three-year period is used to develop the ranking. Hydro One's benchmark score used is the average of 2023 to 2027. The Company would rank 40th in the entire sample if we used the 2017 to 2019 average for Hydro One.

[57] There are 81 U.S. utilities in the sample and adding Hydro One makes 82.

Figure 11 Ranking of Utilities by Distribution Total Cost Scores



4.5 Reasons for Different Transmission and Distribution Benchmark Results

In Hydro One's prior transmission application, the OEB Decision noted the different benchmark results for the transmission and distribution businesses of the Company and asked for an explanation for the different results to be provided at the next rebasing application.[58] A similar difference in benchmarking results persists through the current research found in this report. Hydro One's transmission operations have benchmark scores indicating a superior total cost performance, while Hydro One's distribution operations have benchmark scores that indicate a slightly above average level of total cost. The rest of this section provides some explanatory factors for this difference.

At a high level, Hydro One's transmission system is more similar to its peers and the benchmarking sample than the distribution system is with no available distribution model variables to adjust for this dissimilarity. The transmission system is vast and transmits electricity to rural, municipal, and urban centers. This is similar to many of the transmission utilities in the sample. However, Hydro One's distribution system is unique in serving remote areas, the density of its service territory, and having most of the lower-cost municipal and suburban areas not included within its service territory. This leaves Hydro One with the much higher-cost rural territories to which the Company is required to deliver electricity. This contrasts with its sampled peers whose service territories do include these lower cost suburban areas. Since Hydro One is the only utility with this disadvantage, we cannot develop a variable to adjust for this service territory condition present on the distribution system. Given this reality, we would expect the Company's transmission operations to score better than its distribution operations.

A further explanation of the differences in the benchmark results is the differences in the capital age results for transmission and distribution. Hydro One's transmission capital age is significantly older than

[58] OEB Decision in EB-2019-0082 at pg. 34.

the industry benchmark. Hydro One's distribution capital age is near the industry benchmark level. Older assets will be more depreciated and acquired at a lower cost level than newer assets. This difference in the capital age results helps explain the differences in the transmission and distribution total cost benchmark results.

Some additional underlying explanations for the differences in benchmark results could be the historical realities of Hydro One's distribution system. These historical facts of Hydro One's distribution system still may have a lasting impact on cost levels and, thus, the benchmark scores. In discussions with the Company, it is Clearspring's understanding that several mergers throughout the years (particularly at the turn of this century) meshed diverse systems together into one Company.

One challenge resulting from the historical mergers is that Hydro One has a distribution system that is comprised of many different voltage levels. Our understanding (based on information from the Company), is that these numerous voltage levels create cost challenges that would not otherwise exist (such as increased inventory requirements for station transformers and a need for a more diverse fleet of mobile unit substations). Most other distribution utilities in the sample do not have this historical challenge. This creates a disadvantage to Hydro One that is not being adjusted for within the benchmark model.[59] The transmission system does not have this same historical challenge of meshing different systems together on such a large scale; therefore, this could be a further explanation for the different performance results.

In its Decision in the last transmission application the OEB noted that it did not have the evidence to make conclusions on why the same company has different transmission and distribution benchmark scores,[60] and also noted that there are significant common costs allocated between the two operations. Although examining this allocation of common costs is outside the realm and scope of our research, we note that common costs are a relatively small percentage of the total costs being evaluated in our benchmarking research and are unlikely to be a significant reason for the benchmark score differences.

The benchmarking research deals with the transmission and distribution businesses of Hydro One independently. The models are separate, with a different sample, and a diverse set of variables in each model. However, if the transmission and distribution actual/proposed and benchmark costs for each study are summed to create a full Hydro One total cost benchmarking evaluation, the full Company has a strong total cost performance result of -18.2%. This result is despite the unadjusted cost challenges of having the low-cost service areas cut out of the Company's distribution service area and the historical challenges resulting from the turn of the century mergers.

[59] Distribution line voltage data is not available for the sample to create a variable that could adjust for this.

[60] See p. 33 of the Decision and Order dated April 23, 2020 in EB-2019-0082.

5 Capital Age

The capital age research examines plant addition and retirement data going back to 1948 to calculate and benchmark the capital age of assets, on an overall basis, within the transmission and distribution industries. Clearspring undertook this research to provide further information and context around both the cost benchmarking and TFP studies conducted and discussed throughout this report.

The age of assets will have a large impact on the costs and measured productivity of the utility and industry. A utility which runs its system with an older asset age, all else being equal, will tend to have lower costs due to depreciation and asset inflation. One probable explanation for Hydro One's strong transmission total cost benchmark score is that the Company has an older capital age than the industry.

Regarding the industry TFP trend, even when the transmission industry capital age remained at the same level during the years of 2000 to 2012, the TFP trend was still negative during that same period. This indicates that overall cost challenges for transmitters may be increasing over time. This negative TFP trend is more pronounced in the recent years when the industry has made investments to lower the capital age.

These calculations are conducted using the financial reporting data provided by utilities in the sample since 1947. This is different than using physical asset reports, which would report actual vintages and ages of assets. We use the financial reporting data, along with certain assumptions, to calculate and ascertain a comparison of the capital age of Hydro One to the industry, and the direction both are moving. The capital age calculations are conducted independently of the total cost benchmarking and TFP research.

The sample used for the industry capital age calculations is the same as the benchmarking sample for the corresponding industry (transmission or distribution).[61] To calculate the transmission industry capital age, we used the transmission total cost benchmarking sample, which includes 59 U.S. transmission utilities. For the distribution industry capital age, we used the distribution total cost benchmarking sample, which includes 81 U.S. distribution utilities.

5.1 Capital Age Methodology

There are three steps in the capital age methodology:

1. Calculate the plant in service amounts for each utility in each year in the applicable industry (transmission or distribution).[62] The vintages are calculated by using the additions for a given year as the value for plant in service in the year those additions were placed in service for all

[61] Both the transmission and distribution capital age calculations include an allocated portion of general plant. This is the same approach as the total cost benchmarking research. General plant will tend to have a lower capital age, thus lowering the measured transmission or distribution capital age.

[62] Like the benchmarking studies, the plant in service calculation includes an allocated amount of general plant for both transmission and distribution. This allocation is based on the ratio of transmission plant to total net of general plant for the transmission capital age study and on the ratio of distribution plant to total net of general plant for the distribution study. Both additions and retirements include this allocated portion of general plant.

calculations in subsequent years, and subtracting retirements recorded in that year from the earliest year that still has a remaining positive value of plant in service.

2. Transform the plant in service vintage estimates to capital quantity vintages by dividing by an asset price deflator in the same year as the plant in service (this is the same asset price deflator used in the benchmarking research). These capital quantity vintages are then used to calculate the average capital age of each utility in the year the calculation is being made.

3. Using the capital age estimates for each utility, an industry weighted average is calculated to determine the transmission or distribution industry age benchmark.

More details for each of these three steps are provided in Appendix B.

5.2 Capital Age Results

The capital age results provide a comparison of Hydro One's capital age, on an overall basis, for both transmission and distribution to the U.S. industry. They also provide a viewpoint in how the capital age is changing over time for Hydro One and the industry, and how the Company's capital age is projected to change based on the proposed investment levels during the CIR period. We note that Hydro One's capital age results will be the most comparable to the U.S. sample in more recent or projected years and less comparable in the earlier years. The same is true for examining the trend in the capital age variable for Hydro One.

5.2.1 Transmission Capital Age

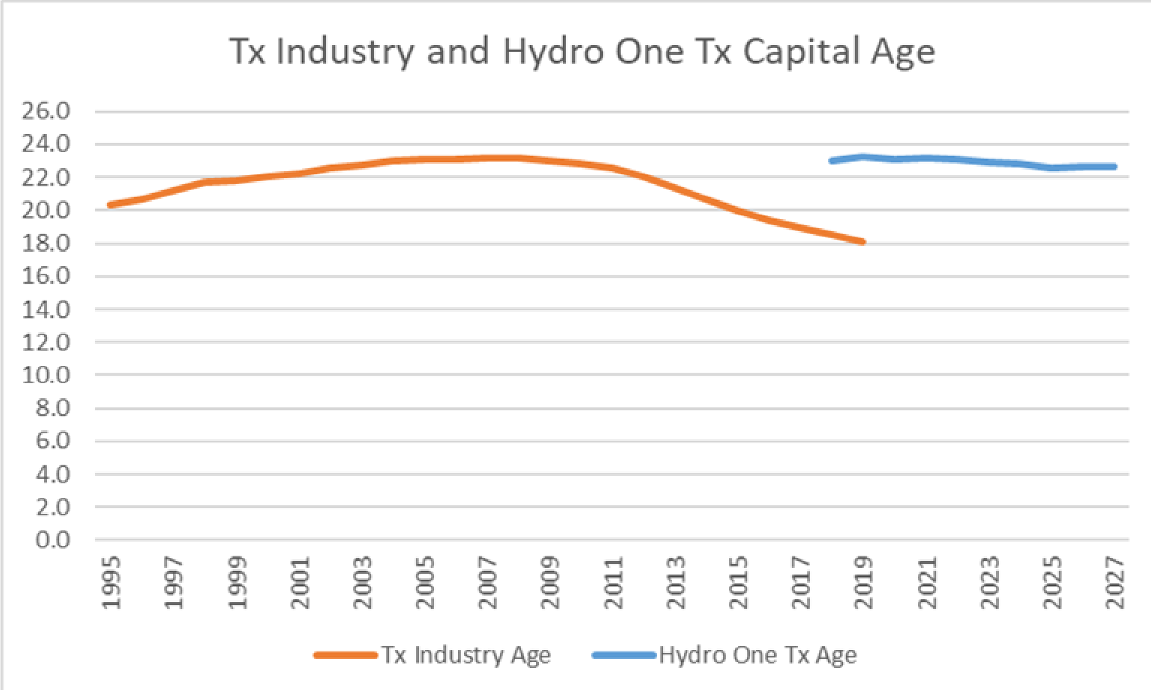
The following table and graph display the U.S. sample aggregate capital age for the transmission industry by year beginning in 1995 through 2019. The table also displays Hydro One's transmission capital age beginning in 2018 through 2027.[63]

[63] This provides 15 years for Hydro One's retirement and additions data to reduce the comparability issues resulting from using the 2003 vintage data to compensate for the lack of historical retirement/addition data prior to 2003.

Table 8 U.S. Sample and Hydro One Transmission Capital Age

Year	U.S. Transmission Industry	Hydro One
1995	20.3	
1996	20.7	
1997	21.2	
1998	21.7	
1999	21.8	
	22.0	
2001	22.2	
2002	22.5	
2003	22.7	
2004	23.0	
2005	23.1	
2006	23.1	
2007	23.2	
2008	23.2	
2009	23.0	
	22.8	
2011	22.6	
2012	22.0	
2013	21.4	
2014	20.7	
2015	20.0	
2016	19.4	
2017	19.0	
2018	18.5	23.0
2019	18.1	23.2
		23.1
2021		23.2
2022		23.1
2023		22.9
2024		22.8
2025		22.6
2026		22.7
2027		22.7

Figure 12 U.S. Sample and Hydro One Transmission Capital Age



Hydro One's transmission capital age during the CIR period is significantly older than the industry's latest capital age value in 2019. Throughout the CIR period, Hydro One's age is above 22.5 years compared to 18.1 years for the industry in 2019. The Company's older transmission capital age is likely one of the main contributors to the Company's strong transmission total cost benchmarking result. Thus far, the Company has been able to maintain this older capital age even while the industry at large substantially increased capital investments and has gotten younger. Combined with the total cost benchmarking results, this capital age result seems to indicate the Company's capital spending proposal is maintaining assets at a relatively older age than the industry can and is resulting in total cost levels considerably lower than our models expect.

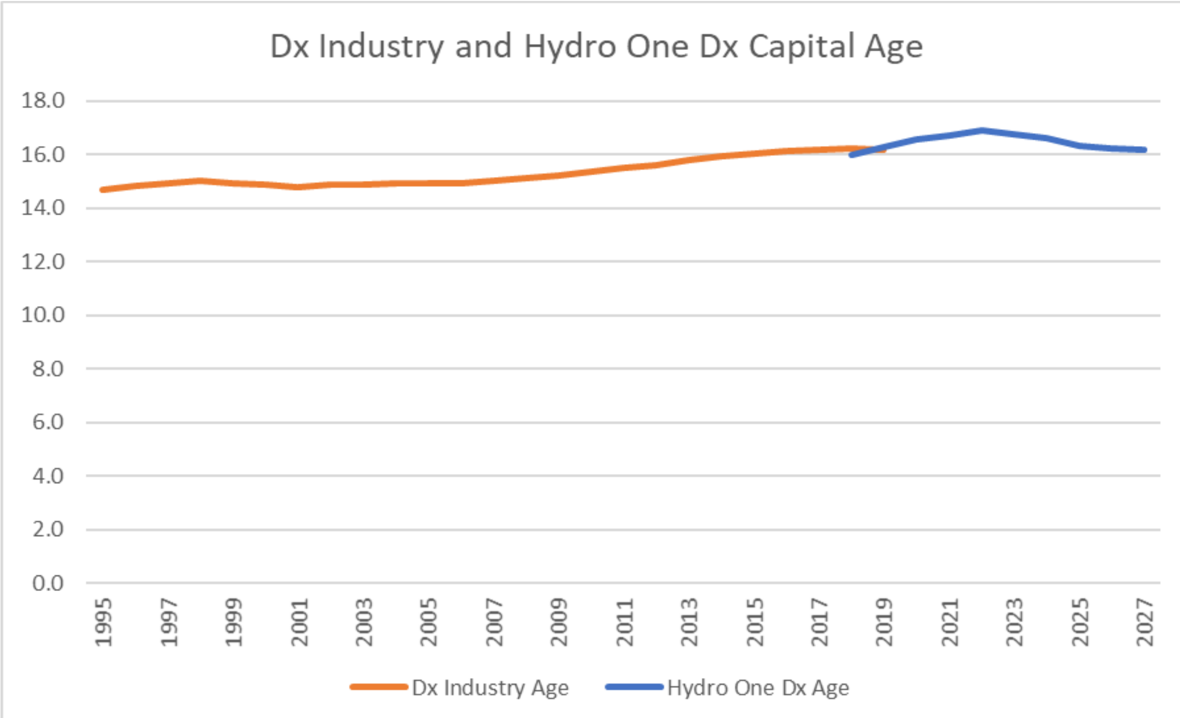
5.2.2 Distribution Capital Age

The following table and graph display the U.S. sample aggregate capital age for the distribution industry by year beginning in 1995 through 2019. The table also displays Hydro One's distribution capital age beginning in 2018 through 2027.[64]

Table 9 U.S. Sample and Hydro One Distribution Capital Age

Year	U.S. Distribution Industry	Hydro One
1995	14.7	
1996	14.8	
1997	14.9	
1998	15.0	
1999	15.0	
2000	14.9	
2001	14.8	
2002	14.9	
2003	14.9	
2004	14.9	
2005	14.9	
2006	14.9	
2007	15.0	
2008	15.1	
2009	15.2	
2010	15.4	
2011	15.5	
2012	15.6	
2013	15.8	
2014	15.9	
2015	16.0	
2016	16.1	
2017	16.2	
2018	16.2	16.0
2019	16.2	16.3
2020		16.6
2021		16.7
2022		16.9
2023		16.8
2024		16.6
2025		16.3
2026		16.3
2027		16.2

Figure 13 U.S. Sample and Hydro One Distribution Capital Age



Hydro One's distribution capital age during the CIR period is near the industry's latest capital age value in 2019. In 2027, Hydro One's age is equal to the latest available benchmark from the industry in 2019. This aligns with our distribution total cost benchmarking finding showing slightly above average cost.

Part of the explanation for the capital age result is the second generation of AMI being deployed during the CIR period. AMI meters tend to have lower service lives than their traditional counterparts and other assets found within the distribution industry. This results in higher proposed plant additions and retirements relative to utilities without AMI or utilities not investing in their second generation of AMI.[65] For context, if the AMI 2.0 project was not planned for during the CIR period, Hydro One's capital age in 2027 is estimated to be 17.3 compared to 16.2 with AMI 2.0. Absent AMI 2.0, Hydro One's distribution capital age would slightly increase during CIR and in 2027 would be 6.8% older than the industry's most recent benchmark in 2019.

---

[64] This provides 15 years for Hydro One's retirement and additions data to reduce the comparability issues resulting from using the 2003 vintage data to compensate for the lack of historical retirement/addition data prior to 2003.

[65] This is not to say that AMI investments are not economic from a societal perspective. AMI can have benefits to society that are not captured directly by the distribution utility. This includes TOU pricing and the impact on generation costs.

6 Transmission Industry Total Factor Productivity

External industry total factor productivity ("TFP") trends form the basis for the base productivity factor ("Base PF") used in the proposed CIR formula. The Base PF should be based on an external measure of the industry TFP trend. Hydro One should have no impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's costs to the allowed revenue escalation. If a utility's own TFP is used within the formula, it will weaken the incentives to enhance productivity and reduce costs.

Clearspring employed a sample of U.S. transmission utilities to calculate the TFP trends of the industry starting in a base year of 2000 and going through 2019. The sample is comprised of 50 U.S. transmission utilities and is shown in the table below.[66]

[66] This table shows both the transmission benchmarking and TFP samples. The TFP sample includes all of the utilities on this table except those with an asterisk. The reason the nine utilities (plus Hydro One) are excluded is because the TFP trend calculations require every utility to have a good observation for every year of the sample period, whereas the benchmarking research does not have this requirement. Hydro One is excluded from the TFP trend sample because excluding it will assure the TFP trend result is fully external to the performance of the Company and the Company does not have available data beginning in 2000.

Table 10 Transmission Benchmarking and TFP Sample

Transmission Benchmarking and TFP Sample

Company	10-Year Average Peak Demand	Tx Line Lengths (KM)	Company	10-Year Average Peak Demand	Tx Line Lengths (KM)
Alabama Power Company	11,578	17,307	Kansas Gas and Electric Company	2,445	4,250
ALLETE (Minnesota Power)*	1,586	4,608	Kentucky Utilities Company	4,488	6,537
Appalachian Power Company	7,517	10,449	Louisville Gas and Electric Company	2,627	1,475
Arizona Public Service Company	7,159	10,106	MDU Resources Group, Inc.	568	5,446
Atlantic City Electric Company*	2,651	2,210	Mississippi Power Company	2,588	3,589
Avista Corporation	1,668	3,610	Monongahela Power Company	2,002	3,613
Baltimore Gas and Electric Company*	6,767	1,490	Nevada Power Company	5,781	3,060
Black Hills Power, Inc.	430	1,244	New York State Electric & Gas Corporation	2,947	7,317
Central Hudson Gas & Electric Corporation	1,129	964	Niagara Mohawk Power Corporation	5,960	17,611
Central Maine Power Company	1,586	4,677	Northern States Power Company - MN	7,604	9,239
Cleco Power LLC	2,471	2,204	Oklahoma Gas and Electric Company	6,657	9,665
Commonwealth Edison Company	21,525	8,015	Orange and Rockland Utilities, Inc.	1,401	889
Consolidated Edison Company of New York	5,070	837	PacifiCorp	10,148	28,350
Duke Energy Carolinas, LLC	17,526	13,329	PECO Energy Company	8,491	2,041
Duke Energy Florida, LLC	9,706	8,354	Potomac Electric Power Company	6,134	1,285
Duke Energy Indiana, LLC	5,885	8,548	PPL Electric Utilities Corporation	7,440	7,244
Duke Energy Progress, LLC	13,171	10,082	Public Service Company of Colorado	6,519	7,721
Duquesne Light Company	2,834	1,075	Public Service Company of New Hampshire	1,641	1,675
El Paso Electric Company	1,804	2,976	Public Service Company of Oklahoma	4,152	5,026
Empire District Electric Company	1,144	2,287	Public Service Electric and Gas Company	10,079	3,237
Entergy Arkansas, Inc.	5,402	8,350	Rochester Gas and Electric Corporation	1,594	1,761
Entergy Mississippi, Inc.*	3,134	5,041	San Diego Gas & Electric Co.	4,530	3,402
Entergy New Orleans, Inc.*	1,071	266	South Carolina Electric & Gas Co.*	4,776	5,915
Florida Power & Light Company	22,956	11,713	Southern California Edison Company	22,502	23,378
Gulf Power Company	2,521	2,739	Southern Indiana Gas and Electric Company	1,224	1,654
Hydro One Networks*	**21,830**	**20,788**	Southwestern Public Service Company*	4,821	12,473
Idaho Power Co.*	3,250	7,692	Tampa Electric Company	3,865	2,164
Indianapolis Power & Light Company	2,853	1,390	Tucson Electric Power Company	2,489	3,523
Jersey Central Power & Light Company*	6,079	4,181	Union Electric Company	7,716	4,115
Kansas City Power & Light Company	3,511	2,919	West Penn Power Company	3,941	3,510

*In Benchmark Sample but not TFP Sample

6.1 Methodology

The output variables, input prices, and cost definitions used for the analysis match those used in the transmission total cost benchmarking research. The only major refinements from the prior transmission TFP research that we conducted in EB-2019-0082 includes modifying the peak demand output definition to the ten-year rolling average and moving the examined sample period back to 2000. Both modifications match the research methodology used for the transmission benchmarking study.[67]

Productivity is defined as the ratio of an output quantity index to an input quantity index. In the case of TFP, the Input Quantity Index includes both capital and OM&A inputs.

$$Productivity = \frac{Output\ Quantity\ Index}{Input\ Quantity\ Index}$$

[67] Please see Section 2.1 for a description of why these two modifications were made.

The output quantity index measures the level of output produced by the utility or industry. The input quantity index measures the level of resources used, such as labour, non-labour OM&A, or capital inputs. Clearspring employs commonly used indexing techniques to capture a comprehensive measure of outputs and inputs, which are in turn used to calculate the productivity term. We then examine how this productivity ratio changes over time to determine the productivity index trend.

The input quantity index is comprised of 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) 10-year rolling average of peak demand. These two outputs are combined into one output index using cost elasticity weights derived from the transmission 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.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

It may be helpful to note that TFP trend measurement differs from total cost benchmarking. With cost benchmarking, utilities are compared relative to the average efficiency level of other utilities within the industry. Conversely, TFP trends measures how productivity is changing over time for that same industry or utility.

6.1.1 Output Quantity Index

This section describes the TFP output quantity index calculations. Clearspring used the same definition of outputs for the transmission TFP study as we did for the transmission total cost benchmarking study. There are two outputs: kilometers of transmission lines and 10-year rolling average peak demand.

The two outputs need to be combined into one output quantity index. We 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 10-year rolling average peak demand, respectively.

The two components of the output quantity index for the industry are provided in the following tables. After combining the components, the overall index is provided in the last column.

Table 11 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Peak Demand	Output Quantity Index
2000	274,815	254,303	1.000
2001	277,846	256,766	1.010
2002	275,583	258,126	1.011
2003	279,327	261,779	1.025
2004	278,234	266,078	1.036
2005	279,193	271,584	1.051
2006	282,986	277,699	1.072
2007	285,486	283,377	1.090
2008	286,091	287,448	1.102
2009	285,843	289,767	1.108
2010	287,110	293,216	1.118
2011	288,316	296,114	1.127
2012	291,320	298,043	1.136
2013	292,641	298,898	1.140
2014	295,024	300,369	1.147
2015	296,872	300,093	1.148
2016	296,435	298,686	1.144
2017	299,331	296,179	1.141
2018	303,004	296,586	1.146
2019	305,952	296,977	1.151
Average Annual Growth Rate			
2000-2019	**0.6%**	**0.8%**	**0.7%**
2010-2019	**0.7%**	**0.1%**	**0.3%**

The transmission industry has experienced output growth around 0.7% per year for the entire output quantity index (2000 to 2019). However, since 2010, the peak demand component of output growth has experienced a slowdown. Over the last 9-year period, it has basically remained flat. This contrasts with transmission line lengths, which have shown relatively steady growth over the sample period.

6.1.2 Input Quantity Index

The input quantity index is comprised of the OM&A quantity and capital quantity. These two measures are then combined using Tornqvist indices based on using the cost shares of each input component. Tornqvist indices are a commonly used indexing methodology, and this is the same approach used in all our prior research.

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. Clearspring used the same cost and price definitions for both the TFP and the benchmarking research.

$$OM\&A\ Quantity_t = \frac{OM\&A\ Expenses_t}{Input\ Price\ Index_t}$$

Clearspring used the same procedures in both the benchmarking and productivity research for the capital quantity index, using the Perpetual Inventory Method with a capital benchmark year of 1947 for most of the sample.[68]

The transmission industry's input quantity index is provided in the tables following. The table displays the industry capital quantity index, OM&A quantity index, and then the combined input quantity index from 2000 to 2019.

[68] Please see the section on the Perpetual Inventory Method found in Appendix A.

Table 12 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2000	955,067	1,702,118	1.000
2001	953,406	1,722,159	1.001
2002	947,164	1,707,804	0.994
2003	953,267	1,776,286	1.007
2004	953,688	2,408,508	1.080
2005	954,028	3,038,175	1.151
2006	964,467	2,868,448	1.141
2007	974,163	2,639,278	1.124
2008	985,250	2,817,461	1.153
2009	1,003,211	2,665,172	1.153
2010	1,028,740	2,878,763	1.197
2011	1,051,164	2,637,361	1.192
2012	1,099,639	2,671,856	1.237
2013	1,153,733	2,721,290	1.289
2014	1,216,944	2,721,180	1.343
2015	1,276,156	2,848,585	1.408
2016	1,325,140	3,036,530	1.470
2017	1,361,708	3,004,692	1.498
2018	1,406,083	3,250,116	1.563
2019	1,452,627	3,009,862	1.576
Average Annual Growth Rate			
2000-2019	**2.2%**	**3.0%**	**2.4%**
2010-2019	**3.8%**	**0.5%**	**3.1%**

The input quantity index has been growing at a faster rate than the output quantity index during the 2000 to 2019 period, and even more during the 2010 to 2019 period. The trend in the capital quantity index has been driving the recent TFP declines that the industry has been experiencing for the last decade. This aligns with the capital age research, showing that the industry is making large capital investments that are lowering the overall system age of the transmission systems.

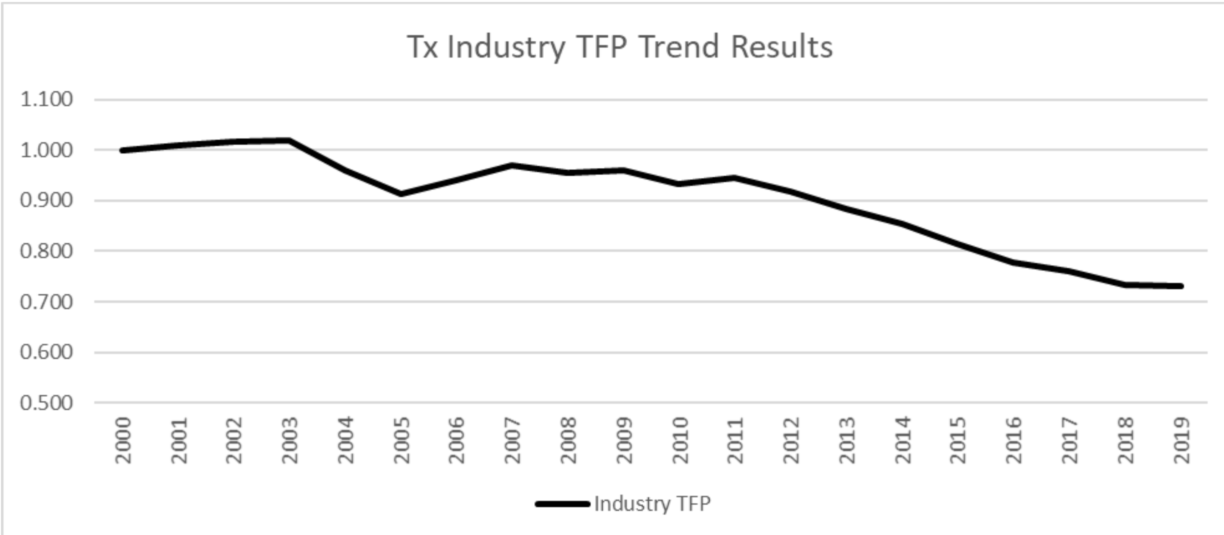
6.2 Transmission TFP Results

The transmission TFP trend results are provided in the following table and displayed graphically in the following figure.

Table 13 Transmission Industry TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate
2000	1.000	
2001	1.009	0.9%
2002	1.017	0.8%
2003	1.018	0.1%
2004	0.959	-6.0%
2005	0.913	-4.9%
2006	0.940	2.8%
2007	0.970	3.2%
2008	0.956	-1.5%
2009	0.961	0.5%
2010	0.934	-2.8%
2011	0.946	1.3%
2012	0.918	-3.0%
2013	0.884	-3.8%
2014	0.854	-3.5%
2015	0.816	-4.6%
2016	0.778	-4.7%
2017	0.762	-2.1%
2018	0.733	-3.8%
2019	0.730	-0.4%
Average Annual Growth Rate		
2000-2019		**-1.66%**
2010-2019		**-2.74%**

Figure 14 Transmission Industry TFP Results



Clearspring calculated the total factor productivity trend for the industry from 2000 to 2019. This nineteen-year period resulted in an average annual decline in industry TFP, with an annual growth rate of -1.66%. Since 2010, the industry TFP has declined at an even higher rate, with an average annual growth rate of -2.74%. Based on OEB precedent, the Base PF is to be set at no lower than 0.0%. However, we note that a PF equal to 0.0% is tantamount to an exceptionally large stretch factor.

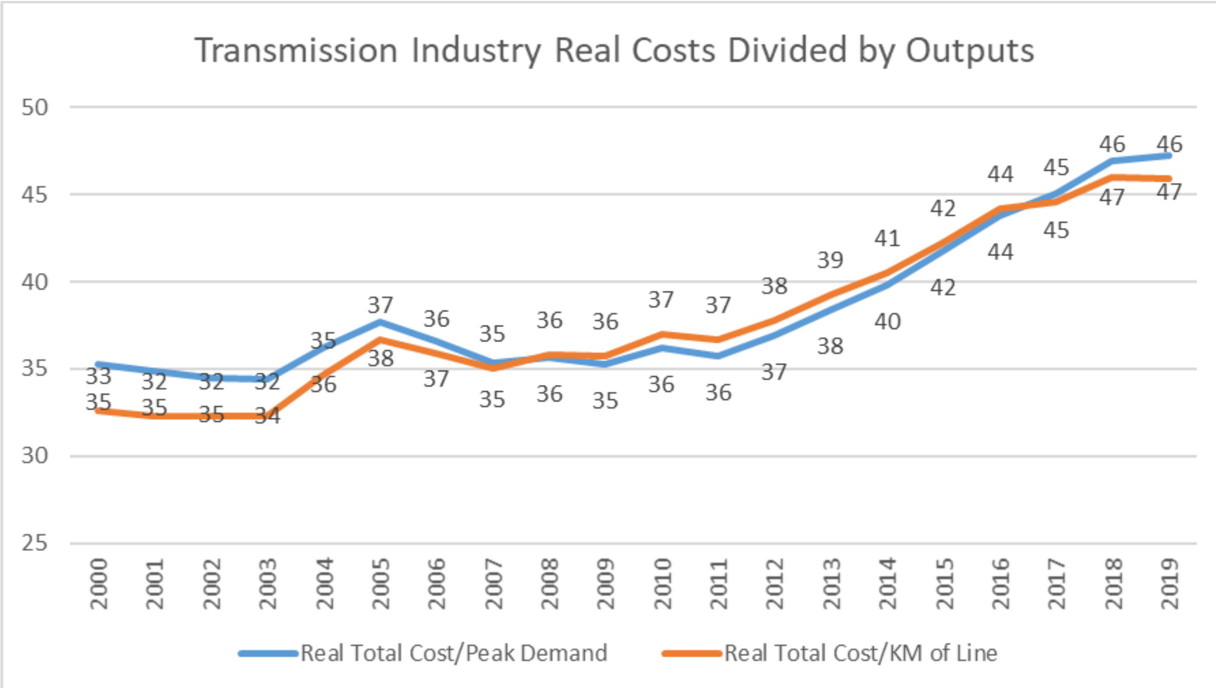
6.3 Interpretation of Negative TFP Growth

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.

The unit cost trends of the transmission industry may help to illustrate the negative TFP trends that are prevalent in the industry during recent years. In the following graph, we display the industry's sum of real transmission total costs (i.e., total costs adjusted for inflation) divided by the industry's sum of each of the two major outputs (peak demand and KM of line).

Figure 15 Transmission Industry Real Costs Divided by Outputs



The transmission industry's real unit costs have increased substantially from the early 2000s to now. There appears to be higher cost pressures on utilities now than twenty years ago. The most pronounced increase in real unit costs also occurred during a period when the capital age of the industry became younger. This is part, but not all, of the explanation.

It is important to note that a negative TFP growth rate does not necessarily 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 Clearspring'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, cybersecurity, safety, meeting increased regulatory requirements, increasing generation interconnections from wind or solar, providing enhanced environmental stewardship, geomagnetic disturbances, and increasing other aspects of power quality and security.

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 the 1950s, 60s, and 70s, 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). We notice in the capital age research for the transmission industry that capital expenditures have been made in recent years to lower the capital age of the industry. These added capital expenditures have lowered the TFP trend of the industry. However, we note that this does not fully explain the negative TFP trends since even during a period when the capital age of the industry was getting older, the industry was still experiencing slightly negative TFP trends.

7 Capital Costs Impact on OM&A Expenses

In the most recent Hydro One transmission application in EB-2019-0082, the OEB Decision stated in the Conclusion on p. 183: "Provide a high level assessment of the correlation, or lack of same, between capital investments and OM&A costs at the program level in future rate applications." Hydro One requested that Clearspring use the econometric model dataset to investigate if correlations are evident in the data between transmission or distribution capital investments and their corresponding OM&A costs.

There may be lengthy lags between when capital increases and when those investments result in OM&A cost savings. Further, increased capital investments may signal the utility doing more for its customers (i.e., increasing unmeasured outputs), and this increased output could translate into higher OM&A expenses rather than a reduction. As the capital age research can also show, increased capital investments do not necessarily mean that the overall capital age of the system is being lowered. If those increased capital investments are merely maintaining the system age, it would not be expected that OM&A expenses would decline since the capital age is not being reduced by the investments.

These realities complicate the development of models that estimate the relationship between capital and OM&A spending. While more research could be conducted to examine the empirical relationship between capital spending increases and OM&A impacts, we were not able to uncover a clear relationship in our initial research.

The table below summarizes the model results by showing the sign on the capital age variable and if the parameter value on it is statistically significant at a 90% confidence level. If OM&A levels decline as age declines, we would expect to see a positive coefficient value. For the full model details, please see Appendix C.

Table 14 OM&A and Capital Age Model Results

Model	Parameter Value on Capital Age	Significant at 90% Level?
Transmission 1: No Lag in OM&A	-	No
Transmission 2: One Year Lag in OM&A	-0.164	No
Transmission 3: Five Year Lag in OM&A	+0.069	No
Distribution 1: No Lag in OM&A	-0.043	No
Distribution 2: One Year Lag in OM&A	-0.092	No
Distribution 3: Five Year Lag in OM&A	-0.058	No

7.1 Capital Costs Impact on OM&A Expenses Conclusion

The six models do not display a consistent empirical story and do not provide evidence that OM&A spending should be expected to decrease through increased capital spending, even as the capital age of the system starts to get younger. The only model that displays a positive correlation between OM&A changes and capital age changes was Transmission Model 3. All other models display an inverse relationship; that is as capital age decreases, OM&A increases. All the model coefficients for the capital age variable were found to be statistically insignificant from zero.

Therefore, with this initial research on this topic, Clearspring is unable to identify a consistent correlation in both the transmission and distribution datasets that aligns with the theory that as capital investments increase enough to reduce capital age, OM&A should decrease. In the case of Hydro One's capital age and its proposed change during the CIR period, this may be a moot point, given that the proposed capital investment levels are not expected to reduce the Company's overall system age to any significant degree.

Appendix A: Total Cost Benchmarking Methodology Details

Variable Types

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 regional input prices, highly congested urban areas, forestation, etc.

Output Variables

The two output variables for the transmission benchmark study are the length of transmission lines and a rolling ten-year average of peak demand. This matches the output variables used in the prior Hydro One transmission research, with the exception the peak demand variable definition is now defined as a rolling ten-year average. This change addresses concerns that as it was defined in previous studies, the peak demand could never decrease.

The three output variables for the distribution benchmark study are the number of customers, a rolling ten-year average of peak demand, and the service area of each utility. This matches the outputs specified in PEG's response to Clearspring's model in the last distribution application for Hydro Ottawa (again, with the modification of the peak demand variable).

For the U.S. utilities, the output variables are calculated from FERC Form 1s. The customers and line lengths are based on the reported data. The peak demand variable is defined for both studies using the annual peak demand value found on p. 401b of the FERC Form 1.[69] This variable consists of the distribution system peak demands plus the required sales for resale. For the transmission study, we did not modify the variable from what is reported in the FERC Form 1. For the distribution study, we adjusted the data to take out the proportion of the required sales for resale. This aligns with the treatment of peak demand that both Clearspring and PEG undertook in the Hydro Ottawa application.

The service area used for each utility is based on variables derived from GIS mappings of each utility's service area. For the U.S. utilities, the values used correspond to what both Clearspring and PEG used in the last Hydro Ottawa application. In the Hydro One Distribution application, one of the concerns brought forth by the intervenors and OEB Staff and mentioned in the Board Decision was the service area value used for Hydro One. In response to those concerns, we have reduced Hydro One's service area to the value used by PEG in its Hydro Ottawa benchmarking research. This reduced the service area variable

[69] In our prior study for Hydro One Transmission, we used the Transmission peaks listed on p. 400 of FERC Form 1. However, this data is not reported prior to 2004, and PEG used the p. 401b data as they thought that may be more suitable, given that some demands are not firm and would not correlate with costs. We see pros and cons with each approach. In an effort to reduce research differences, we use the peak demand data preferred by PEG. This also enables us to roll back the start year to 2000.

value from 961,498 square kilometres served to 651,974 square kilometres served.[70]

Business Condition Variables: Input Prices

Business condition variables are discussed in following sections. However, one important business condition variable merits detailed discussion: input prices. Input prices are divided into two categories: capital and OM&A. The capital input price calculation used in our research is called the Perpetual Inventory Method and is discussed in detail in a following section. The OM&A input price captures the regional market price level that each utility 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. These are labour and non-labour.

The labour component is calculated by taking wage levels of 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 reported 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 from the U.S. and Ontario regarding labour input prices and also puts the input price in terms of each country's currency. We then escalated labour prices for U.S. utilities using BLS employment cost indices for the utility sector and escalated Hydro One prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the U.S. gross domestic product price index for the U.S. utilities. The Hydro One non-labour component uses the Canadian GDP-IPI in each year, but with a levelization adjustment using the purchasing power parity ("PPP") index in 2012. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price we weighted each index using the customized labour and non-labour cost shares calculated from the FERC Form 1 data or based on data provided to us from Hydro One. We then took the OM&A input price and combined it with the capital price using the capital and OM&A cost shares. This produces the total input price index.

Total cost is divided by this comprehensive input price index 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. As the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all utility input prices (including labour) increase by 10%, its costs would also increase by 10%. This is derived from economic production theory, which states that costs equal input quantity multiplied by input price.

[70] The rest of the U.S. sample includes all of the service territory, even if there are no customers within that area.

Other Business Condition Variables

Beyond the output variables and input prices, each model contains business condition variables that provide cost adjustments for given service territory conditions. These variables enable unique service territory conditions to be accurately benchmarked on an "apples to apples" basis. This ability to adjust for specific conditions is why the econometric benchmarking approach is more accurate and fair than unit cost approaches. Unit cost benchmarking tends to only reveal which utility has the most challenging service territory, rather than indicating cost performance. This is because service territory conditions have a profound impact on the cost levels of transmission and distribution utilities. Their capital assets are spread across the entire service territory, and the overall cost levels are thus highly influenced by the conditions the utility is faced with. These cost drivers and specific service territory conditions need to be accounted for to reveal and estimate the performance of the utility.

The business conditions used for the transmission and distribution total cost models are described in each model's specific Chapter.

Perpetual Inventory Method

Total cost is defined as the sum of the annual OM&A expenses plus capital costs. Clearspring's calculation of capital cost is based on the capital service price approach. This approach has a solid basis in economic theory; it is the same method used in all the Ontario benchmarking and productivity studies conducted by Mr. Fenrick, and is the same method chosen by PEG in its 4GIR research and its other studies in CIR applications.[71] The approach allows for a consistent way to account for differences between utilities with respect to historical plant additions and depreciation rates. The service price approach is also prominent in government-sponsored cost research. The Bureau of Labor Statistics of the U.S. Department of Labor uses the capital service price approach in computing multi-factor productivity indices for the U.S. private business sector and for several subsectors, including the utility services industry.

The cost of capital in each year *(t)* is the product of the capital service price index and capital quantity index at the end of the prior year (*t-1)*. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

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 in the prior period.

The capital quantity index (*XK*) is constructed based on the value of net plant in a benchmark year, and on gross plant additions in years subsequent to the capital benchmark year. In an effort to address past concerns of PEG regarding the start year (capital benchmark year) of this capital series, we put

[71] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

considerable effort into gathering and processing U.S. utility data going back to 1947.[72] We use 1947 for most of the U.S. sampled utilities as the capital benchmark year. A few utilities only had consistent data beginning in 1959, for those utilities we used 1959 as the capital benchmark year. We used 2002 as the capital benchmark year for Hydro One, because this is the first year where data is available and can be readily verified.

A "triangulated weighted average" ("TWA") is used to divide the net plant value in order to adjust the net plant value for historical inflation.[73] This results in an estimate of the capital stock in 1947, 1959, or 2002 based on when the capital benchmark year begins for the utility. Subsequent years use the previous year's capital stock multiplied by one minus the depreciation rate and then escalated by that year's plant additions divided by the asset price in that year.[74] This same method is used both Hydro One and U.S. distributors. The formulas for the capital quantity index in 1947 and in subsequent years are provided below.[75]

$$XK_{1947}^{i} = \frac{Net\ Plant_{1947}^{i}}{TWA_{1947}^{i}}$$

$$XK_{t}^{i} = XK_{t-1}^{i} * (1 - d) + \frac{Add_{t}^{i}}{WKA_{t}^{i}}$$

The capital service price (*WKS*) 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 distributors 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 is the economic depreciation rate. For the transmission study, to reduce research differences, we used the same depreciation rate that PEG used in their responding research

[72] In our past studies, we used 1989 for the capital benchmark year, as that was the first year of electronically available data. We considered 1989 to be a sufficient start year for the capital series. However, to reduce the research differences, considerable efforts were invested into gathering and processing these data.

[73] For the U.S. sample, the 1947 or 1959 net plant value is for the total utility. To calculate a transmission or distribution net plant value we multiplied the total net plant value by the percentage of transmission or distribution gross plant in service to total gross plant in service, respectively. We note that any error in this net plant value calculation in 1947 or 1959 will have an extraordinarily minimal impact on the cost levels once the sample starts in 2000. This is because any possible small error in 1947 will have also depreciated for 53 years by the time it enters the sample period.

[74] The historical data going back to 1948 and forward all have plant in service additions disaggregated by transmission and distribution, enabling us to build up a robust capital quantity and cost estimate for each function.

[75] For the Ontario distributors, the subscripts would change to 2002 in the first equation.

d_t

during the Hydro One Transmission CIR application for Hydro One's depreciation rate. This value is 3.30%. For distribution, we use the same value as we have used in all our distribution CIR benchmarking applications and the same one PEG used in the 4GIR proceeding: 4.59%.

The asset price deflator (*WKA*) is an index of the price of capital assets in each year used in either transmission or distribution. In several CIR applications, this has been an area of contention between PEG and our research team. Historically, Clearspring uses the U.S.-based Handy-Whitman indices for both the U.S. sample and Canadian utilities, as these are well-known and provide asset inflation estimates that are specific to electric transmission or distribution.[76] Both Clearspring and PEG (at least historically) use the Handy-Whitman indices for the U.S. sample.

However, when estimating asset inflation for a Canadian utility, PEG has used Handy-Whitman indices in some of its prior research but has preferred a Canadian-specific asset inflation measure in some applications. The advantage of the latter approach is that it is specific to Canadian asset inflation; the disadvantage is that the measure is a comprehensive measure of water, sewer, gas, and electric utilities (including generation). In the Hydro Ottawa CIR research, PEG compromised between these two asset inflation measures and used a 50% weighting on the Handy-Whitman indices and a 50% weighting on their implicit capital stock index measure. For our current research, we have adopted this 50/50 weighting approach put forth by PEG in the Hydro Ottawa application.

For the U.S. sample, we compute this index using data on differences in the cost of constructing utility plant between regions over time. For U.S. distributors, we use the Handy-Whitman indices for total power distribution plant; these indices vary over time and across six geographic regions.[77] We do the same for the U.S. transmission utilities, except using the index for total power transmission plant. For Hydro One, we use the same Handy-Whitman index for total distribution or transmission plant in the North Atlantic region and then adjust for the Canadian purchasing power parity in the given year. This is for half of the weight in the index; for the other half, we use PEG's implicit capital stock deflator index found in the Capital Flows and Stocks data provided by Stats Canada.[78] For future years, we escalate the WKA index using a 50/50 calculation of the projections for the average weekly earnings in Ontario and the GDP-IPI index available from the Conference Board of Canada.

We determine the relative levels of utility plant asset prices for 2015 by using the City Cost Indices for electrical work in the 2016 edition of RSMeans' *Heavy Construction Cost Data*. These indices 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;

[76] For Canadian utilities we adjust the Handy-Whitman for the purchasing price parity (PPPs) in each given year to put the inflation estimate into Canadian dollars.

[77] Handy-Whitman indexes are widely used throughout the U.S. utility industry. They measure the construction cost trends for specific utility functions in six different regional areas of the U.S. For more information, please see: https://wrallp.com/about-us/handy-whitman-index

[78] We note that at the time of the research, this Canadian index was only available through 2019. For 2020, we escalated the Hydro One index fully by the appropriate Handy-Whitman index.

boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution.

We modified this calculation in response to concerns in prior Hydro One applications. The prior method was to calculate the level of the asset price index for each utility by the headquarter city in the service territory (or the closest available city). The concern was that Hydro One, while headquartered in Toronto, has most of its assets outside the City of Toronto, and Toronto tends to have relatively high price levels.

In response to this concern, we modified the asset price level calculation to be based on a population-weighted average of the RS Means value for each 3-digit zip code served by a given utility. This spreads the levelization across the entire service territory, rather than centering on the headquarter city. For Hydro One, we took a population-weighted average of all the Ontario values in the RS Means book. This spreads the levelization across all of Ontario rather than centering on Toronto. The index is already adjusted for currency differences between the two countries.

Model Estimation Procedure and Specification

We assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers," can be quantified and captured by a statistical function. This function, called a "cost function," allows Clearspring 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.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely outside the control of a firm's managers. On the other hand, the number of employees hired is within management's control, and thus should not serve as an independent variable.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2000 and extending to 2019.[79] For benchmarks of past years, we use the model to produce benchmarks for each year and compare Hydro One's benchmark costs with its actual costs.

Additionally, for future years we can take Hydro One's cost projections through 2027, allowing us to also

[79] The data extends to 2027 for Hydro One.

benchmark those forecasts “out of sample.”[80] We use the model (which is based on historical data) and apply the estimated coefficients and projected independent variable values for Hydro One to calculate a predicted benchmark value. This predicted benchmark value is then compared to Hydro One’s projected total cost amount.

Statistical Tests on Parameter Estimates

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. 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% confidence threshold in our research for all first order terms. This restriction is not placed on the quadratic and interaction output terms that comprise the translog cost function.

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 distribution costs rise as the number of customers served increases (i.e. we expect that the customer parameter would be positively signed).

Once the industry cost model is estimated, the 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 for a particular utility reflects the performance we would expect from an average hypothetical utility facing the business conditions of that utility.

If a given utility’s actual cost is below the benchmark cost, its cost performance is better than average—it spent less than a 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.

Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form we have used in all our prior CIR research, and the one chosen by PEG in its 4GIR benchmarking research. The function’s general form, after suppressing time and firm subscripts, is given by:

[80] For Hydro One’s OM&A, Clearspring Energy was given projections until 2023 and then we applied the I-X formula to escalate OM&A amounts in years 2024 to 2027. The I-X formula matches how the Company is proposing to escalate OM&A revenue during those years.

$$ln\left(\frac{C}{W}\right) = \propto_0 + \sum_i \alpha_i \, ln \, Y_i + \sum_j \alpha_j lnZ_j + \frac{1}{2}\left[\sum_{i,k} \propto_{ik} \, lnY_i * ln \; Y_k\right] + \alpha_t t + \varepsilon$$

In this specification, $\alpha's$ are model parameters, and ε is the random noise term. In addition, quantifies output, W is the input price, Z_j is the other business condition variables, and t is a time trend term. This form has been widely used in cost function research.[81] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[82]

Estimation Approach

As discussed earlier, the estimation approach has generated considerable discussion between benchmarking consultants in prior CIR proceedings. This is especially difficult for intervenors and the Board, due to the intricacies and difficulties for non-econometricians to evaluate these different approaches. However, PEG, in its latest benchmarking research conducted in Quebec, appeared to use the same estimation approach that Clearspring has used in the past, and is using in this report. Our hope is that PEG will continue to use this same estimation approach (which uses the OLS parameter estimates but then adjusts the standard errors) in any possible benchmarking research in this application. Clearspring believes this would best serve the Ontario industry for the benchmarking consultants to use consistent and pre-determined estimation approaches for all CIR benchmarking research.

The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the models. In our present two benchmarking studies, we have an unbalanced panel dataset with cost data from multiple utilities with multiple observations starting in 2000 and extending to 2019 (or 2027 for Hydro One).

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 causes the coefficient values to be biased or less precise. 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 standard error estimates which

---

[81] In their Monte Carlo studies of functional forms' performance, Gagne and Ouellette (1998) use the translog as a benchmark because "it is the most widely used" functional form.

[82] See Guilkey, et al. (1983)

Y_i

measure 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.[83] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[84] The computer software calculates information crucial to understanding whether each relationship (as described by each coefficient) can be supported statistically.

[83] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[84] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

Appendix B: Capital Age Calculation Details

As stated in Section 5, there are three steps in the capital age methodology:

1. Calculate the plant in service amounts for each utility in each year in the applicable industry (transmission or distribution).[85] The vintages are calculated by using the additions for a given year as the value for plant in service in the year those additions were placed in service for all calculations in subsequent years, and subtracting retirements recorded in that year from the earliest year that still has a remaining positive value of plant in service.

2. Transform the plant in service vintage estimates to capital quantity vintages by dividing by an asset price deflator in the same year as the plant in service (this is the same asset price deflator used in the benchmarking research). These capital quantity vintages are then used to calculate the average capital age of each utility in the year the calculation is being made.

3. Using the capital age estimates for each utility, an industry weighted average is calculated to determine the transmission or distribution industry age benchmark.

Plant in Service Vintage

The capital age calculation begins in the year 1947 for most of the U.S. sample. The entire amount of the transmission or distribution total plant in service is first assumed to have been put in service in that start year of 1947. In each subsequent year, the reported plant in service additions are recorded in the year that they were reported in (e.g., 1970 plant additions are placed in 1970 and, for example, in the 2000 calculation would be 30 years old) and the reported plant retirements are subtracted from the earliest year that still has positive plant in service value.[86] This calculation continues for every year up through 2019 for the sample.

This calculation is done in every year after 1947 for every utility in the sample.[87] In each new year t, the remaining plant for all prior years is examined. The retirements reported in year t are subtracted from the earliest year that still has a positive value of plant in service. The plant additions reported in year t are assumed to be the amount of new plant in service for year t.

---

[85] Like the benchmarking studies, the plant in service calculation includes an allocated amount of general plant for both transmission and distribution. This allocation is based on the ratio of transmission plant to total net of general plant for the transmission capital age study and on the ratio of distribution plant to total net of general plant for the distribution study. Both additions and retirements include this allocated portion of general plant.

[86] By the start of 1995, most utilities in the sample have zero remaining plant in service by the start year of 1947, and retirements in years after 1995 were subtracted from additions in years after this start year. This is important, since 1947 assumed all plant in service at that time was added in 1947. This assumption will have a minimal impact on capital age values after 1995 for the sample.

[87] These calculations are done separately for transmission and distribution.

The additions reported in 1948 are recorded and placed in the 1948 value for plant in service, retirements in 1948 are subtracted from 1947's value to formulate the vintages of plant in service in 1948. The same process is conducted in 1949, the 1949 additions are placed in the 1949 value for plant in service, retirements in 1949 are subtracted from what was left from 1947 after the prior year's calculation. In all subsequent years, retirements will keep being subtracted from 1947 until all of the plant in service in 1947 is depleted, then the retirements will be taken from 1948 until that year is depleted and so forth.

An example of the mechanics of this calculation may be helpful. Let us assume year t is 1990 and a specific utility reports $1,000 in transmission plant retirements and $10,000 in new transmission plant additions in 1990. Let us also say that due to the calculations in 1989, there is assumed to be no plant remaining in 1980, but there is still $500 of plant remaining in 1981 and $2,000 of plant remaining in 1982.[88,89] For this illustrative example, additions increase by $1,000 in years subsequent to 1982.

Table 15 Sample Plant in Service Calculation

Year	Plant Vintages as a Result of 1989 Calculation	1990 Reported Retirements	1990 Reported Additions	Plant Vintages as a Result of 1990 Calculation
1979	0			0
1980	0			0
1981	**$500**			**0 (subtracted $500 to bring value to 0)**
1982	**$2,000 (1982 additions)**			**$1,500 (Subtracted off remaining $500 from 1990 retirements)**
1983	$3,000 (Adds in 1983)			$3,000 (Adds in 1983)
1984	$4,000 (Adds in 1984)			$4,000 (Adds in 1984)
1985	$5,000 (Adds in 1985)			$5,000 (Adds in 1985)
1986	$6,000 (Adds in 1986)			$6,000 (Adds in 1986)
1987	$7,000 (Adds in 1987)			$7,000 (Adds in 1987)
1988	$8,000 (Adds in 1988)			$8,000 (Adds in 1988)
1989	$9,000 (Adds in 1989)			$9,000 (Adds in 1989)
1990		$1,000	$10,000	$10,000 (1990 Additions)

In the example calculation above, the $10,000 in additions in 1990 is placed in the 1990 bucket for plant in service. In 1990, $1,000 of plant was retired. We assume that the oldest remaining plant is retired first. In the example, this was the $500 remaining in 1981. However, each year's value cannot go below zero, so only $500 of the $1,000 retired in 1990 is assumed to come from plant constructed in 1981. This leaves

[88] In reality, the remaining plant for utilities will be from years longer than 10 years ago. We say 10 years ago just to simplify the example and reduce table size.

[89] The 1982 value will equal the plant additions reported in 1982, since this number has not had any retirements subtracted from it yet.

another $500 to be retired in the next oldest year with positive plant values, which is 1982. The plant in service in 1982 is reduced by that remaining $500 and moves from a value of $2,000 to $1,500.

This calculation would then be conducted in the next year (1991) using the 1991 reported retirement and additions data. The 1991 retirements would be subtracted from the 1982 remaining plant first, since that is the oldest year with a positive value. All subsequent years will build off the prior year in this fashion up through 2019 for the sample and up through 2027 for Hydro One.

An assumption in the calculation is that plant retirements eliminate the oldest available plant in service. Since we do not know the vintages of the gross plant in service at each utility or the vintages of the plant being retired in each year, this assumption is necessary to create a level playing field among the entire sample. It will tend to underestimate the capital age since not all retirements will be from the earliest available year. However, this calculation and assumption is consistent over a large span of time and between utilities and provides a view into how capital age of each industry has moved over time and how they benchmark against each other using the same assumption.

Capital Quantity Vintage and Utility Capital Age Calculation

Once we have estimated the vintages of the plant in service, an adjustment for inflation needs to be made to transform the costs into quantity estimates. This is because $10,000 spent in 2000 will purchase far fewer capital assets than $10,000 spent in 1950, for example. Since we are estimating the capital age of the assets, we will need to divide by an asset price index to transform the plant in service costs to a quantity estimate in each year.[90]

To make this transformation, we use the same asset price deflator that we use in the total cost benchmarking research. This asset price deflator is described in Appendix A, "Perpetual Inventory Method", and is designated as "WKA" in that section. This WKA estimates the relative asset prices for each utility, in each year. We divide the plant in service cost estimates in each year t by this WKA in year t to adjust for inflation and transform the costs to a quantity estimate for each utility i.

$$XK_{t,i} = \frac{Plant\ Remaining_{t,i}}{WKA_{t,i}}$$

[90] A basic equation from economics is that cost divided by price equals quantity.

Using the example from the prior section and assuming that for this utility WKA equals "0.8" in 1979 and then increases by 0.1 in each subsequent year, the estimated capital quantity for the 1989 and 1990 calculations are illustrated below.

Table 16 Sample Capital Quantity Calculation

Year	Plant Vintages as a Result of 1989 Plant Calculation	WKA	Capital Quantity Vintages after 1989 Calculation	Plant Vintages as a Result of 1990 Plant Calculation	WKA	Capital Quantity Vintages after 1990 Calculation
1979	0	0.8	**0**	0	0.8	**0**
1980	0	0.9	**0**	0	0.9	**0**
1981	$500	1.0	**500**	0	1.0	**0**
1982	$2,000	1.1	**1,818**	$1,500	1.1	**1,364**
1983	$3,000	1.2	**2,500**	$3,000	1.2	**2,500**
1984	$4,000	1.3	**3,077**	$4,000	1.3	**3,077**
1985	$5,000	1.4	**3,571**	$5,000	1.4	**3,571**
1986	$6,000	1.5	**4,000**	$6,000	1.5	**4,000**
1987	$7,000	1.6	**4,375**	$7,000	1.6	**4,375**
1988	$8,000	1.7	**4,706**	$8,000	1.7	**4,706**
1989	$9,000	1.8	**5,000**	$9,000	1.8	**5,000**
1990				$10,000	1.9	**5,263**

The last step in the capital age calculation is to create a weighted average of the age of the capital quantities for each year of the calculation. The weighted average is calculated by taking the percentage of the capital quantity that remains in each year to the total capital quantity at the utility in that given year. We assumed that assets built in the year of the calculation were 0.5 years old and then added "1" for every year prior.

The 1989 calculation using our prior example is illustrated in the following table.

Table 17 Sample Utility Capital Age Calculation

Year	Capital Quantity Vintages after 1989 Calculation	% of Total Capital Quantity	Age in 1989	Age * % of Total
1979	0	0%	10.5	0.0000
1980	0	0%	9.5	0.0000
1981	500	1.7%	8.5	0.1445
1982	1,818	6.2%	7.5	0.4650
1983	2,500	8.5%	6.5	0.5525
1984	3,077	10.4%	5.5	0.5720
1985	3,571	12.1%	4.5	0.5445
1986	4,000	13.5%	3.5	0.4725
1987	4,375	14.8%	2.5	0.3700
1988	4,706	15.9%	1.5	0.2385
1989	5,000	16.9%	0.5	0.0845
Sum in 1989	**29,547**	**100.0%**		**3.44**

In the illustrative sample calculation, the average age of the assets is 3.44 years in 1989. The 1990 calculation would then be conducted on the capital quantities calculated in the prior table in the 1990 calculation. Naturally, this is just an illustrative example, utilities in the sample will have assets far older than what is presented in this example.

These calculations are conducted on each utility separately and are specific to transmission and distribution. A utility that is in both the transmission and distribution samples will have a separate capital age calculation, one for distribution and one for transmission assets.

Combining Utility Specific Capital Ages to Industry Aggregate

The capital ages for each utility then are aggregated to determine a transmission or distribution industry capital age estimate for each year. This aggregation is conducted by calculating the weighted average capital age based on the percentage of the utility's capital quantity in year t to the sum of the capital quantity of the sample in that same year. For each year, the industry capital age is calculated as:

$$Industry\ Capital\ Age_t = \frac{\sum_i Capital\ Age_{i,t} * Capital\ Quantity_{i,t}}{\sum_i Capital\ Quantity_{i,t}}$$

Hydro One Calculation

The Hydro One capital age calculations are conducted using the same methodology as the U.S. sample, with the exception that Hydro One does not have addition and retirement data going back to 1948. It does have addition and retirement data beginning in 2004. To address this, the Company provided us vintage schedules that provided the vintages by historical of gross plant in service in 2003. This gives us a starting point to estimate the available plant in service vintages and begin the calculation from. After 2003, we then follow the same calculations as the U.S. sample, where the additions enter in as plant in service for that year and retirements reduce the plant in service for the earliest year where there remains positive plant in service. The Hydro One capital age calculations continue through 2027. These are based on the proposed plant additions and retirements for the transmission and distribution operations of the Company.

There are a couple of comparability issues caused by the lack of addition and retirement data prior to 2004. The first is that using the 2003 schedule likely shows Hydro One to be older in 2003 than what the calculation would have shown if the historical data were available. This is because of our assumption that the retirements reduce the oldest plant in service. Retirements do not always correspond to the oldest plant in service. The discrepancy between Hydro One and the sample benchmark caused by this assumption will diminish as the examined year gets further from 2003 and the calculation is able to mimic the U.S. calculation and reduce the impacts of the 2003 assumption. By a year such as 2019, the calculation has had 16 years to reduce this discrepancy. However, we do caution comparing Hydro One's capital age to the industry capital age in the earlier years of the sample.[91]

The 2003 vintage plant data provided to Clearspring did not include years prior to 1950 and appears to have summed up the plant in service in five-year buckets for 1950, 1955, 1960, and 1965. Our assumption is that the year 1950 captured the plant in service from 1950 and prior. The 1955 bucket includes the years 1951 to 1955, and so on. Clearspring assumed this reported dispersal when doing the calculations and made no attempt to evenly spread the plant in service through the applicable years. This would have made Hydro One's capital age appear younger in 2003 than otherwise would be the case. This partially balances out the first comparability issue of needing to start the calculation in 2003 using plant in service vintage data from Hydro One. In the more recent years, such as by 2019, this inaccuracy will have been reduced, as the retirements from 2004 to 2019 would have reduced the plant in those years first, thus reducing and eventually eliminating the inaccuracy.

[91] This is the reason why we only show Hydro One's capital age values starting in 2018. This enabled the calculation 15 years to reduce the discrepancy.

Appendix C: OM&A and Capital Age Correlation Models

We display six models below that show inconsistent results between the change in the capital age variable and the correlation with OM&A. The first three models are for transmission: one with no lag between an increase in spending, a second one with a one-year lag between changes in capital spending and OM&A expenses, and the third with a five-year lag. We do the same for the next three models for distribution. Each model also contains a variable that adjusts for the output growth, since OM&A expenses would be expected to increase as output increases.[92] For the variable to be found to be statistically significant at a 90% confidence level, the absolute value of the T-Statistic needs to be higher than 1.645.

Table 18 Capital Costs Impact on OM&A Expenses: Transmission Model 1

Variable	Estimated Coefficient	T-Statistic
Constant	0.043	4.537
One-Year Change in Tx Output	0.477	0.997
One-Year Change in Tx Capital Age in Year t	-0.197	-1.141

N = 750, R-squared = .00329

Dependent Variable is One Year % Change in Transmission OM&A in Year t

The Transmission Model 1 in Table 18 shows that the one-year change in the transmission capital age that occurs in Year t has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and we note the low explanatory power of the model indicated by the R-squared statistic.

[92] These models are conducted using the ordinary least squares (OLS) method of econometric estimation.

Table 19 Capital Costs Impact on OM&A Expenses: Transmission Model 2

Variable	Estimated Coefficient	T-Statistic
Constant	0.043	4.538
One-Year Change in Tx Output	0.538	1.125
One-Year Change in Tx Capital Age in Year t-1	-0.164	-0.939

N = 750, R-squared = .00273

Dependent Variable is One Year % Change in Transmission OM&A in Year t

The Transmission Model 2 provides a view when the capital age change is lagged by one year and shows that the one-year change in the transmission capital age that occurs in Year t-1 (one year lag) has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level.

The model results in Transmission Model 2 are like those in Transmission Model 1; both indicate that OM&A spending actually increases as capital spending increases (since more capital spending will tend to decrease the capital age). Both models indicate this with a low level of statistical confidence and low explanatory power of OM&A changes provided by the model.

Table 20 Capital Costs Impact on OM&A Expenses: Transmission Model 3

Variable	Estimated Coefficient	T-Statistic
Constant	0.047	11.674
Five-Year Change in Tx Output	1.512	5.140
One-Year Change in Tx Capital Age in Year t-5	0.069	0.937

N = 750, R-squared = .0362

Dependent Variable is Five Year % Change in Transmission OM&A in Year t

The Transmission Model 3 provides a view when the capital age change is lagged by five years and the OM&A spending change is over the subsequent five year period. The coefficient estimate changes sign compared to Transmission Model 1 and Transmission Model 2 on the capital age variable, indicating that there is a positive relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is increased, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is decreased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and there remains a very low explanatory power of the model indicated by the R-squared statistic. We now turn to the distribution models.

Table 21 Capital Costs Impact on OM&A Expenses: Distribution Model 1

Variable	Estimated Coefficient	T-Statistic
Constant	0.022	4.037
One-Year Change in Customers	0.822	1.732
One-Year Change in Dx Capital Age in Year t	-0.043	-0.204

N = 1,035, R-squared = .00290

Dependent Variable is One Year % Change in Distribution OM&A in Year t

The Distribution Model 1 shows that the one-year change in the distribution capital age that occurs in Year t has an inverse relationship with the percentage change in OM&A spending but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level, and we note the low explanatory power of the model indicated by the R-squared statistic.

Table 22 Capital Costs Impact on OM&A Expenses: Distribution Model 2

Variable	Estimated Coefficient	T-Statistic
Constant	0.023	4.060
One-Year Change in Customers	0.823	1.738
One-Year Change in Dx Capital Age in Year t-1	-0.092	-0.426

N = 1,035, R-squared = .00304

Dependent Variable is One Year % Change in Distribution OM&A in Year t

The Distribution Model 2 provides a view when the capital age change is lagged by one year and shows that the one-year change in the distribution capital age that occurs in Year t-1 (one year lag) has an inverse relationship with the percentage change in OM&A spending, but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is reduced, or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level.

The model results in Distribution Model 2 are like those of the Distribution Model 1, both indicating that OM&A spending actually increases as capital spending increases (since more capital spending will tend to decrease the capital age). Both models indicate this with a low level of statistical confidence and low explanatory power of OM&A changes provided by the model.

Table 23 Capital Costs Impact on OM&A Expenses: Distribution Model 3

Variable	Estimated Coefficient	T-Statistic
Constant	0.021	11.301
Five-Year Change in Customers	0.695	3.976
One-Year Change in Dx Capital Age in Year t-5	-0.058	-0.959

N = 1,035, R-squared = .01554

Dependent Variable is Five Year % Change in Distribution OM&A in Year t

The Dx Model 3 provides a view when the capital age change is lagged by five years and the OM&A spending change is over the subsequent five year period. Unlike the Tx Model 3, the coefficient estimate is the same sign compared to Dx Model 1 and Dx Model 2 on the capital age variable indicating that there is an inverse relationship with the percentage change in OM&A spending but this is not a statistically significant finding at a 90% confidence level. That is, as the capital age gets higher (i.e., older), OM&A spending is decreased or, conversely, as the capital age gets lower (i.e., younger), OM&A spending is increased. Again, the t-statistic indicates this is not a statistically significant finding at a 90% confidence level and there remains low explanatory power of the model indicated by the R-squared statistic.

Appendix D: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.
- "Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

Expert Witness Experience

- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.

- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2014.
- Cooperative Exchange Conference, Williamsburg VA. “Smart Thermostat versus AC Direct Load Control Impacts”. August 2014.
- EUCI conference chair in Chicago. “The Economics of Demand Response”. February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2013.
- EUCI conference chair in Chicago. “Evaluating the Performance of Gas and Electric Distribution Utilities.” August 2013.
- Presentation to the Ontario Energy Board, “Research and Recommendations on 4th Generation Incentive Regulation”.
- Presentation to the Canadian Electricity Association’s best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Reliability Target Setting and Performance Evaluation”.
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Making the Business Case for Reliability-Driven Investments”.
- Conference chair for EUCI conference in 2012 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. St. Louis.
- Conference chair for EUCI conference in 2012 titled, “Demand Response: The Economic and Technology Considerations from Pilot to Deployment”. St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, “Maximizing the Value of DSM Deployments”. Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

COMPONENTS OF CUSTOM IR FORMULA - TRANSMISSION

1.0 HYDRO ONE TRANSMISSION – RCI COMPONENTS

This exhibit describes the specific parameters of the Custom Revenue Cap Index (RCI) proposed for Hydro One Transmission. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor; and
- "C" is Hydro One's Custom Capital Factor.

1.1 INFLATION FACTOR

For its Transmission business, 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 industry-specific weighting of 14% labour and 86% non-labour is supported by the independent analysis conducted for Hydro One and approved by the OEB in both EB-2018-0218[1] and EB-2019-0082.[2] The weightings were also adopted by the OEB in its November 9, 2020 letter setting out inflation parameters for utilities.[3]

---

[1] Hydro One Sault Ste. Marie LP Application for electricity transmission revenue requirement beginning January 1, 2019 and related matters.
[2] EB-2019-0082, Decision and Order, pg. 25
[3] Available at https://www.oeb.ca/sites/default/files/OEB-ltr-2021-inflation-updates-20201109.pdf

In the November 9, 2020 letter, the OEB released the latest Inflation Factor of 2.0% for transmission, for use in applications for rates effective in 2021. Hydro One has used the 2021 Inflation Factor on a pro-forma basis in its RCI calculation for the years 2024 to 2027.

The Inflation Factor will be updated annually over the 2024-2027 period to reflect the OEB issued factors applicable to those years.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor (X-factor) is equal to the sum of Hydro One's Custom Industry Total Factor Productivity (TFP) measure and Hydro One's Custom Productivity Stretch Factor.

Hydro One engaged an independent consultant, Clearspring Energy Advisors (Clearspring), to undertake a study of the TFP trend for the transmission industry and to undertake an econometric total cost benchmarking study of Hydro One's Transmission costs in order to recommend a Custom Productivity Stretch Factor. Clearspring also conducted a separate analysis which calculated the overall age of Hydro One's assets relative to those of the industry at large. The Clearspring study is provided in Exhibit A-04-01-01.

Based on the Clearspring study, the proposed X-factor of 0% for Hydro One Transmission reflects the sum of the Custom Industry TFP measure of 0% and a Custom Productivity Stretch Factor of 0%. Clearspring's study concluded that the transmission industry TFP is -1.66% from 2000 to 2019. Even though the industry TFP is negative, Clearspring proposed a Custom Industry TFP measure of 0% in light of and consistent with previous OEB decisions, including in EB-2010-0379. Clearspring noted that the adoption of an industry TFP measure of 0% would represent a significant implicit stretch factor for Hydro One. Hydro One has adopted Clearspring's proposal.

Clearspring recommended a Custom Productivity Stretch Factor of 0% for Transmission, based principally on the results of its total cost benchmarking study which shows Hydro One to be a very strong cost performer. In that study, Hydro One Transmission's projected total costs were found to average 34.5% below the benchmark costs throughout the Custom IR term. Hydro One ranked well in the top quartile in this regard. Clearspring's recommended stretch factor of 0% is supported by: (1) Hydro One's superior Transmission total cost performance score and ranking, (2) the Transmission capital age results, indicating Hydro One's capital age is older than the sample, (3) the stretch factor implicit in a 0% base productivity factor, (4) Hydro One's proposed incremental stretch factor on capital of 0.15%, as detailed below, and (5) the application of all stretch factors on a cumulative basis. Hydro One has adopted this recommendation.

Clearspring's stretch factor recommendation is also consistent with the approach under the OEB's 4th Generation IRM (4GIRM). As noted in the OEB's 4GIRM report, the OEB set "the lower-bound stretch factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers."[4]

Consistent with the approach in previous applications, the X-factor used in the RCI will not be updated annually over the Custom IR term. In its total cost benchmarking study, Clearspring conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected total costs will remain significantly below benchmark expectations and Hydro One's internal TFP will remain above that of the industry over the Custom IR term. Further details can be found in Clearspring's report provided in Exhibit A-04-01-01.

1.3 CAPITAL FACTOR

The Custom Capital Factor (C-factor) is the percentage change in the Total Revenue Requirement (line 18 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. The C-factor is reduced by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor includes depreciation, return on equity, interest and taxes attributable to new capital investment placed

[4] Report of the Board – Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379, Dec. 2013), p. 20

in-service each year of the Custom IR term. The C-factor will be updated annually to reflect any changes to inflation. The calculation of the C-factor is set out in Table 1.The Total Capital Related Revenue Requirement (line 6 of Table 1) each year is based on the annual rate base.

The final capital related revenue requirement metrics in lines 1 to 12 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with the OEB's decision in EB-2019-0082, working capital has been removed from the calculation of the C-factor as shown in lines 7 and 11 of Table 1. These metrics will not change over the Custom IR term.

The OM&A (line 13 of Table 1) for each year is determined based on the 2023 forecast included in the Application, increased by the Inflation Factor (I) and subject to the proposed X-factor, for a total increase of 2.0% per annum.

Table 1 - Summary of Revenue Requirement Components ($ Millions) for Hydro One Transmission

Line		Reference	2023	2024	2025	2026	2027
1	Rate Base	C-01-01	14,592.7	15,450.3	16,448.9	17,394.1	18,256.2
2	Return on Debt	F-01-02	339.5	359.5	382.7	404.7	424.8
3	Return on Equity	F-01-01	486.8	515.4	548.7	580.3	609.0
4	Depreciation (note 1)	E-08-01 D-01-01	528.2	557.6	593.8	625.1	647.3
5	Income Taxes	E-09-01	40.5	70.9	61.4	83.1	84.3
6	**Total Capital Related Revenue Requirement**		**1,395.1**	**1,503.4**	**1,586.7**	**1,693.2**	**1,765.4**
7	Less Working Capital Related Revenue Requirement		2.2	2.3	2.3	2.4	2.4
8	**Total Capital Related Revenue Requirement (excluding working capital)**		**1,392.9**	**1,501.1**	**1,584.4**	**1,690.7**	**1,763.0**
9	Less Productivity Factor on Capital (0.00%+0.15%)			(2.252)	(2.377)	(2.536)	(2.645)
10	Less Prior Year Productivity Factor on Capital				(2.252)	(4.628)	(7.164)
11	Less Removing Working Capital from Capital Factor			(0.1)	(0.0)	(0.1)	(0.0)
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**		**1,395.1**	**1,501.1**	**1,582.1**	**1,685.9**	**1,755.6**
13	OM&A (note 1)	E-02-01 D-01-01	428.1	436.7	445.4	454.3	463.4
14	**Total Revenue Requirement**		**1,823.2**	**1,937.8**	**2,027.5**	**2,140.3**	**2,219.0**
15	Increase in Capital Related Revenue Requirement			106.1	81.0	103.9	69.7
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			5.82%	4.18%	5.12%	3.26%
17	Less Capital Related Revenue Requirement in I-X			1.53%	1.55%	1.56%	1.58%
18	**Capital Factor**			**4.29%**	**2.63%**	**3.56%**	**1.68%**

**Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment as further explained in Section 4 of Exhibit D-01-01*

The 2023 Total Revenue Requirement of $1,823.2M (line 14 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2024, the Capital Related Revenue Requirement (line 6 of Table 1) increases to $1,503.4M from $1,395.1M in 2023. Hydro One will reduce the Capital Related Revenue Requirement excluding working capital (line 8 of Table 1) by the approved X-factor and the Supplemental Stretch of 0.15% (line 9 of Table 1). In 2025-2027 Hydro One will also reduce the Capital Related Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 10 of Table 1), and Hydro One has reduced the Capital Related Revenue Requirement to account for the impact of the X-Factor on working capital (line 11 of Table 1).[5] The change in Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) in 2024 versus 2023 is $106.1M (line 15 of Table 1). This difference is equal to 5.82% of the 2023 Total Revenue Requirement of $1,823.2M ($106.1M divided by $1,823.2M).

The 5.82% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2024 Capital Related Revenue Requirement (line 12 of Table 1). However, the 5.82% 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 excluding working capital and Productivity (line 12 of Table 1) that is already provided for by the Inflation and Productivity Factors. In 2024, this equals 1.53% ($1,395.1M x 2% / $1,823.2M). The net result of 4.29% (5.82% less 1.53%) is the 2024 Custom Capital Factor. As noted in Exhibit A-04-01, Hydro One has modified the application of its productivity factors so that they are applied on a cumulative basis. The cumulative application of the Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2024.

---

[5] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

1.4 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2024 to 2027.

Table 2 - Custom Revenue Cap Index (RCI) by Component (%) for Hydro One Transmission

Custom Revenue Cap Index by Component	2024	2025	2026	2027
Inflation Factor (I)	2.00	2.00	2.00	2.00
Productivity Factor (X)	0.00	0.00	0.00	0.00
Capital Factor (C) *	4.29	2.63	3.56	1.68
Custom Revenue Cap Index Total	6.29	4.63	5.56	3.68

** Includes a Supplemental Stretch of 0.15% on capital.*

The Inflation Factor in Table 2 will be updated annually, as described above in section 1.1. Hydro One proposes that the X-factor remain unchanged throughout the Custom IR term. The Total Capital Related Revenue Requirement in line 12 of Table 1 would remain unchanged in subsequent annual update applications, however the 2024 to 2027 C-factors would be updated for the applicable year, to reflect the OEB's annual inflation factor, in subsequent annual update applications. Table 3 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 3 - Hydro One Transmission Revenue Requirement by Year

Year	Formula	Revenue Requirement ($millions)
2023	Cost of Service	$1,823.2
2024	2023 Revenue Requirement x 1.0629	$1,937.8
2025	2024 Revenue Requirement x 1.0463	$2,027.5
2026	2025 Revenue Requirement x 1.0556	$2,140.3
2027	2026 Revenue Requirement x 1.0368	$2,219.0

**Calculations assume that Inflation Factor remains at 2% through term.*

2.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications from 2024-2027. These applications are expected to be filed in August.

These applications would calculate the revenue requirement for Hydro One Transmission using the RCI to reflect the most up to date Inflation Factor. Hydro One Transmission will also provide revised Uniform Transmission Rate calculations that reflect the revised revenue requirement and OEB-approved billing determinants for the applicable year. 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.

COMPONENTS OF CUSTOM IR FORMULA - DISTRIBUTION

1.0 INTRODUCTION

This exhibit describes the components of the Custom Revenue Cap Index (RCI) proposed for Hydro One Distribution. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor; and
- "C" is Hydro One's Custom Capital Factor.

1.1 INFLATION FACTOR

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 (I) to be used in incentive-based rate adjustment mechanisms for electricity distributors.

The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Consistent with its prior Custom IR application, Hydro One proposes to use the same Inflation Factor in its RCI.

On November 9, 2020,[1] the OEB released the latest Inflation Factor of 2.2% for distribution, for use in applications for rates effective in 2021. Hydro One has used the 2021 Inflation Factor on a pro-forma basis in its RCI calculation for the years 2024 to 2027.

The Inflation Factor will be updated annually over the 2024-2027 period to reflect the applicable factors in those years, consistent with current OEB practice.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor (X-factor) is equal to the sum of the OEB's industry Total Factor Productivity (TFP) measure for distributors and Hydro One's Custom Productivity Stretch Factor. Based on the recommendations of its independent consultant, Clearspring Energy Advsiors (Clearspring), Hydro One is proposing an X-factor of 0.3% for Hydro One Distribution. The Clearspring study is provided in Exhibit A-04-01-01.

Clearspring undertook an econometric total cost benchmarking study of Hydro One's Distribution costs in order to recommend a Custom Productivity Stretch Factor. The study found Hydro One Distribution's costs to average 7.0% above the benchmark costs over the Custom IR term, and Clearspring accordingly recommended a stretch factor of 0.3%.

Clearspring also recommended an industry TFP measure of 0% based on the results of the latest Ontario TFP study conducted in Hydro One's last Distribution application (EB-2017-0049) and on the 4GIRM results, both of which showed negative industry TFP trends. The recommendation of 0%, which Hydro One has adopted, is consistent with previous OEB decisions.

The above components combine to form the proposed X-factor of 0.3%.

---

[1] Available at https://www.oeb.ca/sites/default/files/OEB-ltr-2021-inflation-updates-20201109.pdf

As detailed in section 1.3 below, Hydro One has modified the application of the X-factor such that it will be applied in a cumulative manner to both OM&A and capital.

Consistent with the approach in previous applications, the X-factor in the RCI will not be updated annually over the Custom IR term. In its total cost benchmarking study, Clearspring conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected cost performance over the Custom IR term would indicate a 0.3% stretch factor, based on established OEB precedent. Further details can be found in Clearspring's report provided in Exhibit A-04-01-01.

1.3 CAPITAL FACTOR

The Custom Capital Factor (C-factor) is the percentage change in the Total Revenue Requirement (line 18 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers through the I – X adjustment. The C-factor is reduced by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The C-factor will be updated annually to reflect any changes to inflation. The calculation of the C-factor is set out in Table 1.

The Total Capital Related Revenue Requirement (line 6 of Table 1) each year is based on the annual rate base.

The final capital related revenue requirement metrics in lines 1 to 12 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with the OEB's decision in EB-2017-0049, working capital has been removed from the calculation of the C-factor as shown in lines 7 and 11 of Table 1. These metrics will not change over the Custom IR term.

The OM&A (line 13 of Table 1) for each year is determined based on the 2023 forecast included in the Application increased by the Inflation Factor (I) and subject to the proposed X-factor, for a total increase of 1.9% (2.2% - 0.3%) per annum.

Table 1 - Summary of Revenue Requirement Components ($ Million) for Hydro One Distribution

Line		Reference	2023	2024	2025	2026	2027
1	Rate Base	C-01-01	9,372.0	9,962.9	10,641.2	11,301.8	11,880.5
2	Return on Debt	F-01-02	219.4	233.3	249.2	264.6	278.2
3	Return on Equity	F-01-01	312.7	332.4	355.0	377.0	396.3
4	Depreciation (note 1)	E-08-01 D-01-01	460.1	481.3	522.0	557.3	592.3
5	Income Taxes	E-09-01	37.2	54.6	42.4	59.2	68.7
6	**Total Capital Related Revenue Requirement**		**1,029.4**	**1,101.5**	**1,168.6**	**1,258.1**	**1,335.5**
7	Less Working Capital Related Revenue Requirement		17.2	17.4	17.5	17.8	18.0
8	**Total Capital Related Revenue Requirement (excluding working capital)**		**1,012.2**	**1,084.1**	**1,151.0**	**1,240.3**	**1,317.5**
9	Less Productivity Factor on Capital (0.30%+0.15%)			(4.879)	(5.180)	(5.582)	(5.929)
10	Less Prior Year Productivity Factor on Capital				(4.879)	(10.058)	(15.640)
11	Less Removing Working Capital from Capital Factor			0.2	0.4	0.6	0.8
12	**Total Capital Related Revenue Requirement (excluding working capital and Productivity)**		**1,029.4**	**1,096.8**	**1,158.9**	**1,243.1**	**1,314.8**
13	OM&A (note 1)	E-03-01 D-01-01	603.0	614.5	626.1	638.0	650.2
14	**Total Revenue Requirement**		**1,632.4**	**1,711.3**	**1,785.1**	**1,881.1**	**1,965.0**
15	Increase in Capital Related Revenue Requirement			67.5	62.1	84.2	71.7
16	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.13%	3.63%	4.71%	3.81%
17	Less Capital Related Revenue Requirement in I-X			1.20%	1.22%	1.23%	1.26%
18	**Capital Factor**			**2.93%**	**2.41%**	**3.48%**	**2.56%**

**Note 1: The OM&A and Depreciation lines reflect the Proposed PCB Treatment as further explained in Section 4 of Exhibit D-01-01*

The 2023 Total Revenue Requirement of $1,632.4M (line 14 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2024, the Capital Related Revenue Requirement (line 6 of Table 1) increases to $1,101.5M from $1,029.4M in 2023. Hydro One will reduce the Capital Related Revenue Requirement excluding working capital (line 8 of Table 1) by the approved X-factor of 0.3% and the Supplemental Stretch of 0.15% (line 9 of Table 1). In the years 2025-2027, Hydro One will also reduce the Capital Related Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 10 of Table 1). Hydro One has reduced the Capital Related Revenue Requirement to account for the impact of the X-factor on working capital (line 11 of Table 1).[2] The change in Total Capital Related Revenue Requirement excluding working capital and Productivity (line 12 of Table 1) in 2024 versus 2023 is $67.5M (line 15 of Table 1). This difference is equal to 4.13% of the 2023 Total Revenue Requirement of $1,632.4M ($67.5M divided by $1,632.4M).

The 4.13% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2024 Capital Related Revenue Requirement (line 12 of Table 1). However, the 4.13% 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 excluding working capital and Productivity (line 12 of Table 1) that is already provided for by the Inflation and Productivity Factors. In 2024, this equals 1.20% ($1,029.4M x 1.9% / $1,632.4M). The net result of 2.93% (4.13% less 1.20%) is the 2024 Custom C-factor. As noted in Exhibit A-04-01, Hydro One has modified the application of its productivity factors so that they are applied on a cumulative basis. The cumulative application of the X-factor and Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2024.

[2] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

1.4 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2024 to 2027.

Table 2 - Custom Revenue Cap Index (RCI) by Component (%) for Hydro One Distribution

	2024	**2025**	**2026**	**2027**
Inflation Factor (I)	2.20	2.20	2.20	2.20
Productivity Factor (X)	-0.30	-0.30	-0.30	-0.30
Capital Factor (C) *	2.93	2.41	3.48	2.56
Custom Revenue Cap Index Total	**4.83**	**4.31**	**5.38**	**4.46**

** Includes Supplemental Stretch of 0.15% on capital.*

The Inflation Factor in Table 2 will be updated annually, as described in section 1.1 above. Hydro One proposes that the X-factor in Table 2 will remain unchanged throughout the Custom IR term. The Total Capital Related Revenue Requirement in line 12 of Table 1 above would remain unchanged in subsequent annual update applications, however the 2024 to 2027 C-factors would be updated, for the applicable year, to reflect the OEB's annual inflation factor in subsequent annual update applications.

Table 3 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 3 - Hydro One Distribution Revenue Requirement by Year

Year	Formula	Revenue Requirement ($M)
2023	Cost of Service	$1,632.4
2024	2023 Revenue Requirement x 1.0483	$1,711.3
2025	2024 Revenue Requirement x 1.0431	$1,785.1
2026	2025 Revenue Requirement x 1.0538	$1,881.1
2027	2026 Revenue Requirement x 1.0446	$1,965.0

2.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications from 2024-2027. These applications are expected to be filed in August.

These applications would calculate the revenue requirement for Hydro One Distribution using the RCI to reflect the most up to date Inflation Factor. Hydro One Distribution will also dispose of Group 1 deferral accounts if appropriate and update Retail Transmission Service Rates.

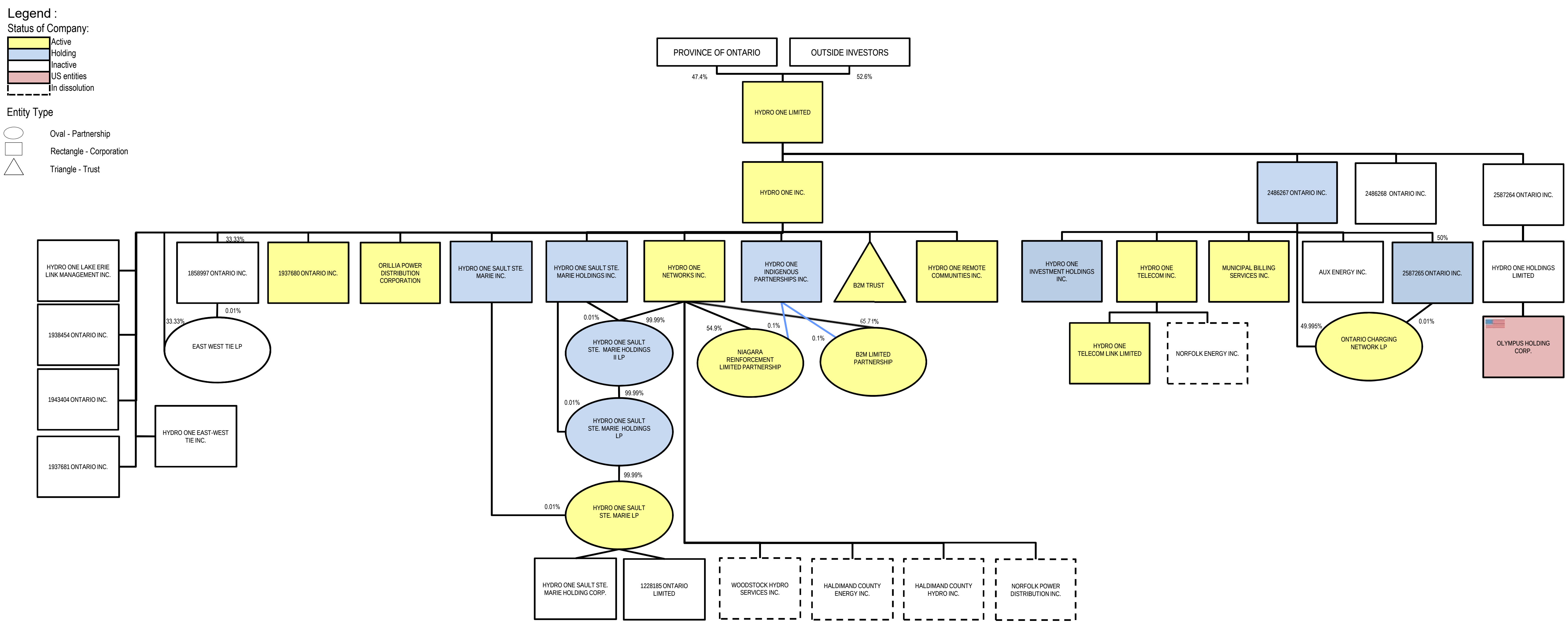
CORPORATE ORGANIZATION CHARTS

Attachment 1 sets out the corporate organizational structure for the Hydro One group of companies as of December 2020.

Attachment 2 sets out the executive and senior management positions within Hydro One.

This page left blank intentionally.

HYDRO ONE
ORGANIZATIONAL CHART AS AT 2020-12-31



Hydro One Organization Structure

Filed: 2021-08-05
EB-2021-0110
Exhibit A-5-1
Attachment 2
Page 1 of 1

President and Chief Executive Officer
Mark Poweska

- **Strategic Advisor** – Cassidy McFarlane

SVP, Technology & CIO – Brad Bowness
- Chief Security Officer – Ben Blakely
- Vice President, Business Solutions – Kelly Kingsley
- Director, IT Operations – Peter Mitskos
- Director, Enterprise IT – Glen Reaume
- Project Director – Kevin Marcotte

Chief Corp Affairs and Cust Care Officer – Jason Fitzsimmons
- Vice President, Stakeholder Relations – Daniel Levitan
- Vice President, Indigenous Relations – Penny Favel
- Vice President, Customer Service – Spencer Gill
- Vice President, Communications & Marketing – Jay Armitage
- Director, Partnerships & External Relations – Jessica Bentley-Jacobs
- Director, Business Services – Siobhan Smith

Chief Operating Officer – David Lebeter
- Vice President, Transmission and Stations – Andrew Spencer
- Vice President, Planning & Engineering – Bruno Jesus
- Vice President, Distribution – Chong Kiat Ng
- Vice President, System Operations – Martin Huang
- Vice President, Forestry – Teri French
- Managing Director, Remotes – Kraemer Coulter
- irector, Business Performance – ed Lyberogiannis

Chief Financial Officer – Chris Lopez
- Senior Vice President, Finance – Joseph Cornacchia
- Senior Vice President, Strategy & Growth – Jason Rakochy
- Senior Vice President, Pensions – Robert Cultraro
- Vice President, Treasury – Ali Suleman
- Vice President, Audit & Risk – Kris Wentzel
- Vice President, Investor Relations – Omar Javed
- Vice President, Shared Services – Rob Berardi

Chief Human Resource Officer – Megan Telford
- Vice President, Talent and Culture – Farah Alexis
- Vice President, Workforce Innovation – Nadine O'Neil
- Vice President, Total Rewards – Vatche Rubenyan
- Director, HR Planning and Integration – Chris Polsinelli
- Director, HR Service Centre – Trudy Shields
- Director, Human Resources – Erin Kinlin

Chief Legal Officer – Paul Harricks
- Vice President Reliability Standards & CRO – Frank D'Andrea
- Corp Secretary & Corp Ethics – Maureen Wareham
- Asst. General Counsel & CRO – Adele Pantusa
- Asst. General Counsel – Ann Yu
- Asst. General Counsel & CRO – Michael Engelberg

Chief Safety Officer – Lyla Garzouzi
- Director, Environmental Services – Elise Croll
- Director, Health & Safety – Scott Vicary
- Director, HSE Management Systems – Dale Shafer
- Director, Environment H&S Audit – Janet Holt
- Director, HSE Training & Development – Dale Spicer

Legend
- Vacant role
- Acting

PACIFIC ECONOMICS GROUP DISTRIBUTION TOTAL COST BENCHMARKING FORECAST

1.0 INTRODUCTION

As part of Section 2.1.8 of the Distribution Filing Requirements, an applicant must provide a forecast of its efficiency assessment using the Pacific Economics Group Research, LLC (PEG) forecasting model for the test year for the purposes of providing the OEB with a directional indicator of efficiency. Hydro One has included a live Excel version of the PEG forecasting model populated with Hydro One Distribution's historical and forecast costs as Attachment 1 to this Exhibit. The PEG model forecasts that Hydro One's test year costs would assign Hydro One to the Group 4 stretch factor ranking and result in a stretch factor of 0.45%. Hydro One does not propose to adopt this stretch factor.

As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One engaged Clearspring Energy Advisors LLC (Clearspring) to conduct a total cost benchmarking analysis of Hydro One's costs. Based on the results of the Clearspring analysis, Hydro One proposes that the adoption of a stretch factor of 0.3% is more reflective of Hydro One Distribution's cost performance. Hydro One is committed to increasing productivity and efficiency company-wide as it strives to be a best-in-class, customer-centric, commercial entity. Developing a culture of continuous improvement is pivotal to producing a business plan and application that align customer needs and preferences, the condition and compliance needs of its assets, and rate impacts. The steps taken by Hydro One Distribution to improve productivity and efficiency are described in System Plan Framework (SPF) section 1.4.

This page left blank intentionally.

PEG BENCHMARKING SPREADSHEET FORECAST MODEL

This exhibit has been filed separately in MS Excel format.

ELECTRICITY SERVICE QUALITY REQUIREMENTS

1.0 INTRODUCTION

Hydro One Distribution monitors and reports service quality indicators as required by the Ontario Energy Board's (OEB) Reporting and Record-keeping Requirements (RRR). The Electricity Service Quality Requirements (ESQRs) included in this Application are set out in Chapter 7 of the Distribution System Code (DSC). Hydro One tracks and internally reports results on ten customer service quality indicators on a monthly basis. Reports are provided to the OEB annually in accordance with the DSC.

Hydro One's customer service results and targets are reported for the past five historical years, 2016 to 2020, as required by the Board in Section 2.2.2.8 of Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. Over the historical period, Hydro One Distribution met or exceeded all of the OEB customer service indicator targets except Emergency Rural Response in 2016-2018 and 2020 and Rescheduling a Missed Appointment for 2016-2018.

2.0 CUSTOMER SERVICE INDICATORS

Hydro One consistently tracks, analyzes and reports ten customer service indicators on a monthly basis as part of its internal performance reporting process. This process identifies areas of concern so that Hydro One's performance can be immediately addressed and brought back in line with OEB requirements.

In an effort to develop a culture of continuous improvement, analysis of monthly and annual result trends provides valuable information for corporate planning, program planning and management of resources for services.

2.1 DEFINITIONS

The ten customer service indicators are defined below.

2.1.1 APPOINTMENTS

2.1.1.1 APPOINTMENT SCHEDULING

The percentage of appointment scheduling requests that are made within five business days of the day on which all applicable service conditions are satisfied or at a later date agreed upon by the customer and Hydro One. This applies regardless of whether the customer or customer representative's presence is required.

In instances where a customer or a customer representative presence is required, Hydro One must offer to schedule the appointment during Hydro One's regular hours of operation within a window of time no greater than four hours, and must attend the meeting at the appropriate time. This does not apply to appointments that are subject to the requirements in the section on Connection of New Services.

The OEB Minimum Standard for this measure is 90%.

2.1.1.2 APPOINTMENTS MET

The percentage of appointments at a customer's premises or work site met at the appointed time of the customer's choosing (defined as morning or afternoon of a particular date). This indicator includes appointments for disconnects and/or reconnects for maintenance or upgrades, connecting new services, underground cable locates, inspections, meter reading and instructions on prepaid meters. The appointment may be considered to be met even when the customer failed to attend.

The OEB Minimum Standard for this measure is 90%.

2.1.1.3 RESCHEDULING A MISSED APPOINTMENT

In instances when appointments need to be rescheduled, this indicator measures the percentage of instances in which Hydro One has made: (i) an attempt to inform the customer before the scheduled appointment that the appointment is going to be missed; and (ii) made and an attempt to reschedule the appointment one business day following the initial appointment. This does not apply if the appointment is missed due to the failure of customer or customer representative to attend.

Section 7.5 of the DSC requires that, where an appointment is missed or is going to be missed, distributors must attempt to contact the customer: (a) before the scheduled appointment to inform the customer that the appointment will be missed; and (b) within one business day to reschedule the appointment.

The OEB Minimum Standard for this measure is 100%.

2.1.2 CONNECTION OF NEW SERVICES

2.1.2.1 LOW VOLTAGE CONNECTIONS

The percentage of requests for connection of a new low voltage service (<750 V) that are completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One.

The OEB Minimum Standard for this measure is 90%.

2.1.2.2 HIGH VOLTAGE CONNECTIONS

The percentage of requests for connection of a new high voltage service (≥750 V) that are completed within ten business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One. Hydro One does not separately report on this measure due to the complexity of gathering the data. The ≥750 volts connections are included with the < 750 V connections which is a more stringent measure. All connections that are not met within five days are analysed to confirm that no connections ≥750 volts failed.

The OEB Minimum Standard for this measure is 90%.

2.1.3 EMERGENCY RURAL RESPONSE

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for rural utilities. Due to the predominantly rural nature of its distribution system, Hydro One Distribution is required to meet the 120 minutes response time. The elapsed time is measured from the call to the arrival of Hydro One qualified service personnel on site.

The OEB Minimum Standard for this measure is 80%.

2.1.4 TELEPHONE

2.1.4.1 TELEPHONE ACCESSIBILITY

The percentage of incoming calls answered within 30 seconds by the customer care center. Time begins at the moment the customer chooses to speak to a customer service representative (using the interactive voice recognition system) or from first ring in all other cases.

The OEB Minimum Standard for this measure is 65%.

2.1.4.2 TELEPHONE CALL ABANDON RATE

The percentage of incoming calls abandoned before being answered following the 30 second period outlined in 2.1.4.1 Telephone Accessibility.

The OEB Standard for this measure is 10%.

2.1.5 WRITTEN RESPONSE TO ENQUIRIES

This indicator measures the percentage of responses to requests by a customer for written information relating to their accounts made within the performance standard of ten working days following receipt of the request or, if applicable, ten working days from the date on which any conditions associated with their enquiry have been satisfied. The written response is deemed to be sent on the date it is faxed, mailed or e-mailed by Hydro One, and when it includes a written acknowledgement of receipt of the qualified enquiry and a specific date in which a complete response will be provided.

2.1.6 RECONNECTION PERFORMANCE STANDARD

The percentage of reconnections of a disconnected customer for non-payment that are completed within two business days after the customer has made full overdue payment or entered into an arrears payment agreement with Hydro One.

The OEB Minimum Standard for this measure is 85%.

3.0 RESULTS

The performance results of the ten Customer Service Performance Indicators from 2016 through 2020 are shown in Table 1 and in Exhibit A-05-03, Attachment 1. The required targets for each measure, as specified by the DSC, are also shown. Hydro One Distribution has met or exceeded all of these indicators with the exception of Emergency Rural Response in 2016-2018 and 2020 and Rescheduling a Missed Appointment for 2016-2018.

Table 1 - Customer Service Indicators

Indicator	OEB Minimum Standard	2016	2017	2018	2019	2020
Low Voltage Connections[1]	90.00%	98.60%	98.10%	99.30%	99.80%	99.80%
High Voltage Connections*	90.00%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility[2]	65.00%	74.20%	81.90%	78.10%	76.80%	70.20%
Appointments Met[3]	90.00%	99.50%	98.90%	100.00%	100.00%	100.00%
Written Response to Enquires	80.00%	100.00%	100.00%	100.00%	100.00%	99.33%
Emergency Rural Response**	80.00%	75.30%	77.28%	65.50%	86.50%	76.50%
Telephone Call Abandon Rate***	10.00%	2.70%	2.10%	3.00%	2.00%	3.90%
Appointment Scheduling	90.00%	99.50%	99.00%	100.00%	100.00%	100.00%
Rescheduling a Missed Appointment	100.00%	98.50%	99.70%	97.30%	100.00%	100.00%
Reconnection Performance Standard	85.00%	98.50%	98.20%	98.30%	99.80%	98.50%

**High Voltage Connections results are included with Low Voltage results.*
***Emergency Response results include the impact of Force Majeure events.*
****Telephone Call Abandon Rate OEB Minimum Standard of 10.0% should be interpreted as no more than 10.0% of calls.*

3.1.1 EMERGENCY RURAL RESPONSE IN 2016-2018 & 2020

For 2020, Hydro One reported a result of 76.5% against the OEB Minimum Standard of 80%. Hydro One did not meet this standard due to significant increases in storm events during the year. Three major storms in June, July, and November of 2020 contributed to the final result. In June, 2020, high winds and thunderstorms from June 10 to June 13 affected all zones with 212,405 total customers affected. 260 out of 579 emergency calls were classified as Most Prominent Events which is our measure of Force Majeure, with 165 of those calls having failed. During the July 19th to 21st period, high winds and thunderstorms affected most zones resulting in 120,006 customers

[1] Low Voltage Connections is shown in DSP Section 3.5 as New Residential/Small Business Services Connected on Time.
[2] Telephone Accessibility is show in DSP Section 3.5 as Telephone Calls Answered On Time.
[3] Appointments Met is shown in DSP Section 3.5 as Scheduled Appointments Met On Time.

without power. 124 out of 521 emergency calls were classified as Most Prominent Events with 77 of those calls having failed. From November 1st to 3rd high winds and snow squalls impacted most zones and affected 64,105 customers. From November 15th to 19th, a wind storm affecting all zones resulted in 558,016 customers without power and 673 of 966 emergency calls were classified as Most Prominent Events with 512 of those calls having failed.

For 2018, Hydro One experienced major storms in April, May, June, and September which contributed to the result of 65.5% for the year. In April, an ice storm with 24 hours of freezing rain occurred in Ontario. 520 out of 692 emergency calls were classified as Most Significant Events with 292 of those calls having failed. Wind gusts in excess of 100 km/h resulted in the May 4th wind storm in Ontario, resulting in tornadoes in the Muskoka/Parry Sound areas. 1,122 out of 1,411 emergency calls were classified as Most Significant Events with 973 of those calls having failed. In mid-June, a large storm even resulted 134 emergency calls with 82 failures. On June 30th, 61 out of 497 calls were classified as Most Significant Events with 42 of those calls having failed. On September 21st, over 350 poles were severed and 300,000 customers impacted due to powerful tornados in the Ottawa area. 455 out of 676 emergency calls were classified as Most Significant Events with 289 of those calls having failed.

During the months of January, March, April, May, June, July, and October 2017 Ontario experienced unusually high storm activities causing significant outages. Results for these months were 71.2% in January, 71% in March, 65.5% in April, 74.2% in May, 79.8% in June, 78.7% in July, and 65.7% in October. These months brought the overall year-end results down to 77.28%, which was a slight improvement from previous year.

During the months of February, March, June, July, and August 2016 Ontario experienced unusually large storm events causing significant outages. Results for these months were 79% in February, 35% in March, 78% in June, 78% in July, and 78% in August. These months brought the overall year-end results down to 75.3%.

Hydro One remains focused on the Dx Modernization Program with plans to continue to install additional Communicating Faulted Circuit Indicators (CFCIs) across our worst performing feeders. Initiatives such as these will further enhance Hydro One's system enabling us to reduce patrolling time and safely return power to our customers faster, cutting down the response time significantly. Improving reliability of the grid continues to be an area of focus for Hydro One, and by installing and commissioning new automation devices as well as retrofitting a number of existing assets to enable fault location and remote sectionalizing on the Distribution grid, we will be able to make advances in this area.

3.1.2 RESCHEDULING A MISSED APPOINTMENT IN 2016 TO 2018

In 2018, 433 of 445 appointments were rescheduled successfully prior to the appointment time, and rescheduled within 24 hours resulting in a score of 97.30% which is below the OEB target of 100%. Significant Storm events resulted in 12 appointments not being rescheduled prior to the scheduled appointment time.

For 2017, Hydro One reported a result of 99.7%. In 2017, Hydro One rescheduled 851 out of 854 missed appointments, which was an improvement relative to performance in 2016.

For 2016, Hydro One reported a result of 98.5% which was largely the result of human error as discussed in the last distribution application.[4]

Hydro One has restructured the Distribution organization in an effort to enhance effectiveness and drive improvement throughout the business. In addition to this the Company has implemented enhanced regional reporting dashboards which incorporate all OEB standards and bring visibility to our front line supervisors. Lastly, a continued focus on the adoption of office and field staff to the new mobile work management platform is expected to further improve our ability to schedule and meet our customer appointments.

---

[4] EB-2017-0049, Exhibit A, Tab 5, Schedule 3, Updated 2017-06-07

The following attachment(s) are provided as part of this section:

- Attachment 1 - Appendix 2-G: Service Reliability and Quality Indicators, Dx

Appendix 2-G

Service Reliability and Quality Indicators
2016 - 2020

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days*				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
SAIDI	13.2	13.0	22.9	10.0	14.5	12.6	12.2	21.2	8.9	13.5	8.3	8.5	7.6	8.0	8.2
SAIFI	3.4	3.5	4.3	3.5	3.7	2.9	2.9	3.4	2.8	3.1	2.8	2.8	2.9	3.2	3.1

* Excluding force majeure and including loss of supply

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days*
SAIDI	14.7	13.7	8.1
SAIFI	3.7	3.0	3.0

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

NOTE: For additional detail and discussion, see Exhibit B1-1-1, Section 1.4.2.1

Service Quality

Indicator	OEB Minimum Standard	2016	2017	2018	2019	2020
Low Voltage Connections	90.0%	98.60%	98.10%	99.30%	99.80%	99.80%
High Voltage Connections*	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	74.20%	81.90%	78.10%	76.80%	70.20%
Appointments Met	90.0%	99.50%	98.90%	100.00%	100.00%	100.00%
Written Response to Enquires	80.0%	100.00%	100.00%	100.00%	100.00%	99.33%
Emergency Urban Response	80.0%					
Emergency Rural Response**	80.0%	75.30%	77.28%	65.50%	86.50%	76.50%
Telephone Call Abandon Rate ***	10.0%	2.70%	2.10%	3.00%	2.00%	3.90%
Appointment Scheduling	90.0%	99.50%	99.00%	100.00%	100.00%	100.00%
Rescheduling a Missed Appointment	100.0%	98.50%	99.70%	97.30%	100.00%	100.00%
Reconnection Performance Standard	85.0%	98.50%	98.20%	98.30%	99.80%	98.50%

Results are consistent with the scorecard in DSP Section 3.5. Any differences are due to rounding between this template and the Scorecard produced by the OEB in DSP Section 3.5.

* High Voltage Connections results are included with Low Voltage results.

** Emergency Response results include the impact of Force Majeure events.

*** Telephone Call Abandon Rate OEB Minimum Standard of 10.0% should be interpreted as no more than 10.0% of calls.

ACCOUNTING INFORMATION

1.0 ORGANIZATIONAL STRUCTURE

Hydro One Limited was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, Hydro One Limited acquired all of the shares of Hydro One Inc., thus becoming its parent company. The principal businesses of Hydro One Inc. are the transmission and distribution of electricity to customers within Ontario. These businesses are primarily carried out through Hydro One Networks Inc. (Hydro One Networks), (a wholly owned subsidiary of Hydro One Inc.) by its Transmission and Distribution business units.

Hydro One Limited is currently a U.S. Securities and Exchange Commission (SEC) issuer within the meaning of National Instrument 52-107 – Acceptable Accounting Principles and Auditing Standards (NI 52-107), which enables it to have access to US debt markets. On November 23, 2018, Hydro One Holdings Limited (HOHL), an indirect wholly owned subsidiary of Hydro One Limited, filed a US debt short form base shelf prospectus with securities regulatory authorities in Canada and the United States (collectively, the US debt prospectus), which allows HOHL to offer from time to time up to US$3.0B of US debt securities, unconditionally guaranteed by Hydro One Limited. HOHL and Hydro One Limited subsequently renewed the US debt prospectus on December 17, 2020. Management intends for Hydro One Limited to remain an SEC issuer within the meaning of NI 52-107 for the foreseeable future.

2.0 ACCOUNTING STANDARD

Historically, until December 31, 2010, Hydro One Inc. used legacy Canadian GAAP (CGAAP) as its basis of accounting. Under CGAAP, there was limited accounting guidance on rate regulated operations and in instances where CGAAP did not have the relevant accounting guidance, the prevailing practice was to refer to United States Generally Accepted Accounting Principles (US GAAP), Accounting Standards Update (ASU) 980 - Rate Regulated Operations.

In 2011, a requirement was introduced for Canadian companies to adopt International Financial Reporting Standards (IFRS). However, many Ontario utilities were reluctant to adopt IFRS due to the inability to apply regulatory accounting, and because it was expected to result in significant impacts to ratepayers due to differences in the ability to capitalize overheads under IFRS and the need to incur additional costs (such as for modifications to be made to accounting systems). As a result, Hydro One Networks and other utilities approached regulators such as the Ontario Energy Board (OEB) and the Ontario Securities Commission (OSC) for exemptions from the requirement to adopt IFRS and permission to instead use US GAAP as their basis of accounting, as well as for rate setting purposes.

On November 23, 2011, the OEB issued its Decision with Reasons in EB-2011-0268, granting Hydro One Networks' request to use US GAAP as its accounting standard for regulatory purposes for the Transmission business commencing January 1, 2012. Similarly, on March 23, 2012, the OEB issued its Decision with Reasons in EB-2011-0399, granting the same relief to Hydro One Networks in respect of its Distribution business, with the same commencement date.

Just prior to the applications being filed with the OEB in EB-2011-0268 and EB-2011-0399 (which was prior to the formation of Hydro One Limited), Hydro One Inc. filed an application with the OSC seeking approval to utilize US GAAP as the basis for preparing its financial statements, for the period January 1, 2012 to January 1, 2015. On July 21, 2011, the OSC issued its decision granting exemptive relief to Hydro One Inc. to allow it to continue reporting its financial statements in accordance with US GAAP. This exemptive relief was to remain in effect until the earlier of: (i) January 1, 2015, and (ii) the date on which Hydro One Inc. ceases to have activities subject to rate regulation. In 2013, Hydro One Inc. completed a public offering of its MTN debt securities in both Canada and the US, in connection with which it has debt securities registered in the US and listed on the New York Stock Exchange. As a result, Hydro One Inc. subsequently became an SEC issuer (within the meaning of NI 52-107) and by virtue of that fact was (and still is) permitted to report its financial statements in accordance with US GAAP.

In connection with its initial public offering in August 2015, Hydro One Limited was granted exemptive relief by the OSC, as principal regulator, on behalf of the securities regulators in each province and territory of Canada allowing Hydro One Limited to prepare its financial statements in accordance with US GAAP following its initial public offering. This exemptive relief was to remain in effect until the earlier of: (i) January 1, 2019, (ii) the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

In March 2018, Hydro One Limited applied to extend its exemptive relief and was granted such relief by securities regulators in each province and territory of Canada, thereby allowing Hydro One Limited to continue preparing and reporting its financial statements in accordance with US GAAP. This most recently granted exemptive relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. In 2018, Hydro One Limited also became an SEC issuer (within the meaning of NI 52-107) and by virtue of that fact was (and still is) permitted to prepare and report its financial statements in accordance with US GAAP for securities law purposes.

While the IASB is continuing to develop a standard for rate regulated entities within IFRS, to date it has not mandated the application of such a standard to entities with activities subject to rate regulation. More particularly, on January 28, 2021, an Exposure Draft of a new standard ED/2021/1 on Regulatory Assets and Liabilities (the Exposure Draft) was published by the IASB. The Exposure Draft is subject to a lengthy review and comment period, such that there is currently no certainty with respect to the final substance of the standard or the timing for its application. The Exposure Draft is open for comments until July 30, 2021. The date of the final publication is not known at this time. Once a final standard is issued, it is expected that it would be applicable for annual reporting periods beginning on or after a date that is 18-24 months from the time of the final publication.[1] Even if the standard is adopted, it is expected that the standard would not be made effective prior to January 1, 2024. Notwithstanding the potential issuance of the final standard, both Hydro One Inc. and Hydro One Limited will continue to be permitted to report under US GAAP by virtue of being SEC issuers (within the meaning of NI 52-107).

In the past several rate proceedings, the OEB has questioned Hydro One's continued use of US GAAP. In EB-2016-0160, the OEB indicated that it will consider whether it should initiate a generic policy review regarding whether it is appropriate to allow for the continued use of US GAAP for the purpose of determining the capitalization of overhead amounts.[2] In EB 2017-0049, the OEB stated that it expects to review Hydro One's approach to capitalization in its next Distribution application and that, in order to facilitate such review, Hydro One is expected to provide a report that compares its capitalization of common corporate costs with those of other utilities in Ontario, Canada and North America under US GAAP and IFRS.[3] In EB 2019-0082, the OEB stated that:

> *Hydro One follows US GAAP for regulatory purposes and therefore follows a US GAAP based capitalization policy. Under US GAAP, Hydro One has the ability to capitalize more in the form of overhead costs than it otherwise would be permitted if it had been ordered to follow the OEB's Modified International Financial Reporting Standards (MIFRS) based capitalization policy, with a corresponding reduction in OM&A.*[4]

Furthermore, in its Decision and Order in EB-2019-0082, the OEB stated that in respect of the continued use of US GAAP for regulatory purposes, the issue is to be addressed during the

[1] PwC, US GAAP to IFRS Conversion Impact Review (Exhibit A-6-1, Attachment 1), April 2021, p. 12
[2] EB-2016-0160, Decision and Order, September 28, 2017, Revised October 11, 2017, p. 81
[3] EB-2017-0049, Decision and Order, March 7, 2019, p. 82
[4] EB-2019-0082, Decision and Order, April 23, 2020, p. 93

current joint rate application as part of the capitalization study previously requested in the Distribution decision. Additionally, the OEB indicated that Hydro One should provide the revenue requirement impact and risk analysis with the transition from US GAAP to MIFRS.[5]

In response to these directions, Hydro One selected PricewaterhouseCoopers LLP (PwC) through a competitive procurement process to undertake two comprehensive studies and perform in-depth analysis regarding:

a) Hydro One's approach to overhead capitalization, benchmarking of overhead capitalization against Canadian and North American peer utilities, and assessing the differences with respect to overhead capitalization between US GAAP and IFRS (the Capitalization Analysis); and
b) The risks, costs, timing and revenue requirement impacts of Hydro One transitioning from US GAAP to IFRS (the IFRS Transition Analysis).

With respect to the Capitalization Analysis, PwC concluded that Hydro One's proposed method for capitalizing common corporate costs is reasonable and consistent with the principle that any assignment of indirect costs to capital projects should be based on a reasonable causal link. Moreover, PwC concluded that Hydro One's approach to capitalizing common corporate costs is not inconsistent with the principles of US GAAP or applicable regulatory guidance. PwC's report, *Hydro One Capitalization of Common Corporate Costs Review* (the PwC Report on Capitalization of Common Corporate Costs) is discussed in Exhibit C-08-02 and provided as Attachment 2 thereto.

With respect to the IFRS Transition Analysis, PwC concluded that, for Hydro One to transition to IFRS, the implementation costs would be significant and there would be ongoing maintenance costs incurred, but there would not be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the

[5] EB-2019-0082, Decision and Order, April 23, 2020, p. 95

nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent. PwC's report, *Hydro One US GAAP to IFRS Conversion Impact Review* (the PwC Report on IFRS Conversion) is provided as Attachment 1 to the current exhibit and is discussed in detail in Section 3.0, below.

3.0 PROPOSAL FOR CONTINUED USE OF US GAAP

As noted above, the current exemption from the requirement to use IFRS is effective until January 1, 2024. In event that the exemptive relief expires and is not renewed, Hydro One has evaluated the implications of transitioning to and using IFRS as compared to remaining on US GAAP. Based on this evaluation Hydro One has concluded, for the reasons set out below, that the continued use of US GAAP is in the best interests of both ratepayers and the company. This conclusion is supported by the findings in the PwC Report on IFRS Conversion.

The primary benefit of transitioning to IFRS is that IFRS is a widely used global standard that may allow for the possibility of benchmarking against a greater number of utilities that are regulated by the OEB. As the default standard in Ontario, it has already been adopted by many Ontario utilities. However, as discussed below, there are few, if any, Ontario utilities with a customer base, service territory size, and operating practices comparable to Hydro One. Consequently, this potential benefit of transitioning to IFRS would not be realized in Hydro One's circumstances.

The main drawbacks against Hydro One transitioning to IFRS, as well as key rationale for remaining on US GAAP, are as follows:

1. The rate regulated accounting standards under US GAAP are well established and robust, and are used by various regulated entities in both Canada and the United States, thereby allowing for ease of comparability among utilities in North America. Continued use of US GAAP also allows for continued benchmarking against the historical performance of Hydro One. In addition, remaining on US GAAP allows for continued

benchmarking against other large Canadian companies on US GAAP (example - OPG, Enbridge, and Hydro Quebec) and US peer companies, as applicable.

2. There is currently no formalized rate regulated standard under IFRS. The Exposure Draft issued by the IASB for rate regulated activities has not yet been finalized by the IASB. Moreover, there is currently no certainty with respect to the final substance of the standard or the timing for its application. As such, any adoption of IFRS before the final standard is released may require Hydro One to make further significant changes to its accounting policies and processes. As outlined by PwC, waiting for a new final IFRS guidance before making any decisions with respect to the possibility of Hydro One transitioning from US GAAP to IFRS may be prudent from a cost benefit perspective.[6]
3. A key concept that is proposed as part of the Exposure Draft but which is not typical under US GAAP or the current IFRS 14 framework is the requirement to discount the estimated future cash flows of regulatory assets by using what the Exposure Draft defines as the regulatory interest rate.[7] These would be new concepts to apply for regulatory assets and liabilities on the financial statements, and the new presentation and disclosures may cause confusion to some financial statement users.
4. Conversion to IFRS would introduce challenges, risks, costs and complexity to Hydro One. The challenges include impacts for financial reporting, management reporting, regulatory reporting, capital planning processes, information systems, organizational changes and internal controls. There would be disruption to the organization in order to upgrade systems and processes to capture the data required to meet the requirements of IFRS on transition and on an ongoing basis. Historical data for certain areas, primarily related to capital assets, may not exist and processes may need to be redesigned to capture the additional information required.[8] A comprehensive list of work streams and

[6] PwC Report – US GAAP to IFRS: Conversion Impact Review, Section 3
[7] PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 12
[8] PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 14

key activities that would have to be executed in order for Hydro One to convert from US GAAP to IFRS is detailed in the PwC Report on IFRS Conversion.[9]

5. Though the costs that would be incurred to convert to IFRS would be significant (i.e., labour, system changes)[10] and would need to be recovered through rates, the benefits to customers would be questionable.
6. On transition to IFRS, historical capitalized charges would be expected to remain within capital assets. However, PwC's IFRS Transition Analysis determined that subsequent to adopting IFRS, based on 2023 forecasts, there could be up to $208M of common corporate costs that would be recorded as expenses subject to OEB approval. Notwithstanding that finding, PwC further determined that, if certain accounting processes are amended and updated, specific components of those common corporate costs may ultimately meet the criteria under IFRS for being directly charged to specific capital projects, thereby reducing the impact to revenue requirement. Furthermore, PwC determined that if the OEB maintains the same ratemaking framework and guidance described in the 2007 Handbook, agnostic to the accounting framework, PwC would not expect a significant impact, if any, to future revenue requirements in respect of Common Corporate Costs at Hydro One. As such, despite the significant implementation challenges, risks and costs, and a risk of having to record a significant amount of costs as OM&A rather than as capital upon transition, ultimately PwC found that there may not be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent.[11]
7. IFRS is a principles-based standard which entails significant judgement to be applied by preparers of the financial statements, thereby hindering comparability against other

[9] PwC Report – US GAAP to IFRS: Conversion Impact Review, pp. 14 and 15
[10] PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 19
[11] PwC Report – US GAAP to IFRS: Conversion Impact Review, pp. 6 and 11

utilities. US GAAP standards are rules-based and, as such, they leave very little to the judgement of the preparer of financial information. This results in consistency among companies in their accounting treatments and outcomes for similar transactions.

8. US GAAP standards enable better matching of the costs of getting capital assets to their intended location and ready for their intended use with the benefits that customers receive from those assets as comparted to IFRS, which would treat some of these costs as expenses. In terms of capitalization of indirect overhead costs, as these are allowed, the continued use of US GAAP avoids the risk of rate shock associated with the conversion of rate base into OM&A.[12] This is consistent with the regulatory principles of matching costs with benefits, and establishing rates that provide for intergenerational equity.

Based on Hydro One's evaluation, it has determined that there are no significant benefits to be gained by transitioning to IFRS, that even if there were significant benefits to transitioning it would be premature to do so given the ongoing uncertainty regarding the timing and substance of final standards, and that maintaining the use of US GAAP would avoid disruption to the business and avoid costs for ratepayers and the utility. This is because Hydro One would not have to incur the significant level of effort, risk and cost associated with implementing an IFRS conversion. Immediate material rate increases may also result in intergenerational inequity, depending on the recovery term of the costs.

The PwC Report on IFRS Conversion supports Hydro One's assessment by acknowledging that, given the technically complex systems, processes, and multiple business units involved in a potential conversion, and based on PwC's experience, the implementation costs of converting to IFRS would be significant. Additionally, PwC notes that there could be ongoing maintenance costs that would have to be added to revenue requirement in periods following the initial transition. Furthermore, PwC determined that even if Hydro One did transition to IFRS there is

[12] PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 19

not expected to be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent. In consideration of the PwC findings discussed above, Hydro One does not believe that a change in its accounting standard would itself be a reason for the OEB to change its views in this respect.

4.0 CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its accounting policies and procedures from time to time. There have been no material changes to accounting policies since EB-2017-0049 and EB-2019-0082 with the exception of the items discussed below.

First, in the OEB's Transmission decision in EB-2019-0082, it indicated that the non-service component of Hydro One's OPEB costs shall be recognized as OM&A costs for both its transmission and distribution businesses because continuing to capitalize the non-service component is now prohibited by ASU No. 2017-07. As such, effective from January 1, 2020, for Hydro One Transmission these costs have been expensed to OM&A. Hydro One Distribution has continued to record the non-service component of OPEB costs into its OPEB cost deferral account until December 31, 2022 in accordance with the OEB decision, but moving forward starting in 2023, these costs will be expensed to OM&A to align with the treatment for Hydro One Transmission.

The second area relates to the treatment of cloud computing implementation costs. Accounting Standard Update (ASU) 2018-15 was issued by the Financial Accounting Standards Board in August 2018. This ASU aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalization of implementation costs incurred to develop or obtain internal-use software. Accordingly, the amendments require an entity (customer) in a hosting arrangement that is a service contract to follow the guidance in ASC Subtopic 350-40[13] to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense.

This ASU was effective for entities for fiscal periods beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption of the amendments in this ASU was permitted, including adoption in any interim period, for all entities. Hydro One elected to early adopt ASU 2018-15 on April 1, 2019. The ASU allows Hydro One to capitalize implementation costs on hosting arrangements that is a service contract. Prior to the issuance of this ASU, those costs would have been expensed.

5.0 ACCOUNTING ORDERS

The following regulatory accounts have been established by the OEB (or requested by Hydro One) subsequent to, and outside of its reviews of, Hydro One's Transmission regulatory accounts in EB-2019-0082 and Hydro One's Distribution regulatory accounts in EB-2017-0049:

- Affiliate Transmission Projects (ATP) Account for Transmission[14]
    - Sub-account ATP – Project Development, Preliminary Engineering and Planning Work Deferral
    - Sub-account ATP – Project Construction Costs Tracking

[13] ASC 350 Intangibles – Goodwill and Other covers five subtopics (overall, goodwill, general intangibles other than goodwill, internal-use software, and website development costs).
[14] Hydro One submitted an application with the OEB to establish a Deferral Account for Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169).

- Account 1508 – Other Regulatory Assets, Sub-account Misallocated Future Tax Savings Carrying Charges for Transmission
- Account 1595 – Disposition and Recovery/Refund of Regulatory Balances, Sub-account Principal Balances of Misallocated Future Tax Savings for Distribution
- Account 1595 – Disposition and Recovery/Refund of Regulatory Balances, Sub-account Misallocated Future Tax Savings Carrying Charges for Distribution
- Impacts Arising from the COVID-19 Emergency for both Transmission and Distribution[15]
    - Sub-account Costs Associated with Billing & System Changes
    - Sub-account Lost Revenues
    - Sub-account Other Costs
    - Sub-account Bad Debt
- Capital Contribution Recovery Differential Account for Transmission
    - Sub-account Barrie Area Transmission Upgrade (BATU) Contribution
- Customer Choice Initiative Deferral Account for Distribution

Please refer to Exhibit G-01-01 for more information on these accounts and other regulatory accounts presented in this Application.

[15] On June 17, 2021, the OEB issued the Report of the Ontario Energy Board: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (Report) which establishes guidelines for the COVID-19 deferral account. As a result of the conclusions made in the Report, the OEB indicated that the Account will be organized under the following sub-accounts for all utilities:

- Impacts from Complying with Government/OEB-initiated Customer Relief Programs
- Bad Debt
- Capital-related Revenue Requirement Impacts
- Other Costs and Savings

Table of contents

Purpose, scope and limitations of this report

At the request of Torys LLP, as counsel to Hydro One Networks Inc. (“Hydro One”, “the Company”), as a result of the requests by Ontario Energy Board (“OEB”) outlined in the Decision and Order EB-2019-0082, we have prepared this report to comment on the potential impacts of Hydro One transitioning the measurement and reporting of its revenue requirement, for purposes of seeking rate approvals from the OEB, from Generally Accepted Accounting Principles as issued by the Financial Accounting Standards Board (“US GAAP”) to International Financial Reporting Standards as issued by the International Accounting Standards Board (“IFRS”).

We understand that the purpose of this report is to assist Hydro One with its planned 2023-2027 combined Distribution and Transmission rate application (the “Application”) to be filed with the OEB in 2021.

This report includes:

- an analysis identifying and providing high level summaries of differences between US GAAP and IFRS, which could significantly impact revenue requirement components as a result of transitioning from US GAAP to IFRS;
- a specific analysis of the potential revenue requirement impacts associated with transitioning from US GAAP to IFRS in the context of capitalizing common corporate costs;
- an analysis of potential risks and challenges, impacted processes and systems, and an estimated timeframe and effort of transitioning from US GAAP to IFRS based on PwC’s experience for a typical company of Hydro One’s size and nature; and
- an overview and assessment of the impacts of the Exposure Draft issued by the International Accounting Standards Board on Regulatory Assets and Regulatory Liabilities.

Limitations

This report refers to the methodology outlined by Black & Veatch in its Report on Corporate Cost Allocation Review dated June 9, 2021 (the “B&V Report”) as filed in Hydro One’s Application for the calendar years 2023-2027, inclusive. Specifically, the report refers to the methodology for capitalizing corporate costs for the Tx and Dx businesses as described in Section 6 of that report.

Our work was limited to the procedures and analysis described herein. Our work was performed on the basis that information included in the B&V Report and other information provided to us by Hydro One was accurate and complete. Unless otherwise noted, all references in this report to Hydro One processes, methods and methodologies are as of the date of this report. We did not review Hydro One’s revenue requirement calculations and application for the calendar years 2023-2027 nor audit, verify nor otherwise validate any data nor explanations, except as specifically noted by us in this report. Our engagement cannot be relied upon to disclose errors, irregularities, or illegal acts, including fraud or defalcations that may exist. Further, this evaluation does not constitute an audit, accounting opinion, tax opinion, attest opinion nor any other form of assurance.

This report is intended solely for use by Torys LLP, as counsel to and Hydro One Networks Inc. under the terms of our agreement dated November 23, 2020 for submission to the OEB and is not intended or authorized for any other use or party. If any unauthorized party uses this report, in whole or in part, it is their sole responsibility and their sole and exclusive risk, that they may not rely on the report, that they do not acquire any rights as a result of such access and that PricewaterhouseCoopers LLP does not assume any duty, obligation, responsibility or liability to them.

Executive summary

Changing the basis of accounting from US GAAP to IFRS introduces challenges, complexity, risk and costs to Hydro One which can impact financial reporting, regulatory reporting, information systems, organizational change and internal controls. The transition to IFRS from US GAAP would require changes to financial statement presentation and updates to processes for tracking information for disclosures. On the basis that the Ontario Energy Board ("OEB") does not change its view on the nature/types of cost that are included in the revenue requirement, then presentation aside, a significant difference in overall recognition and measurement would not be expected. Many potential differences between that are identified in this report may be permitted to be recorded as regulatory deferral accounts under IFRS 14, Regulatory Deferral Accounts (IFRS 14), as IFRS 14 largely aligns the measurement and recognition principles of ASC 980, *Regulated Operations* currently applied by the company under US GAAP.

An area of particular focus is the treatment of capitalizable overhead charges. Canadian utility regulators and the U.S. Federal Energy Regulatory Commission (FERC) have historically accepted that indirect activities support capital work and, to the extent that there is a causal link to the capital activities, have allowed the associated costs to be allocated to capital. US GAAP and IFRS are broadly aligned in allowing for the capitalization of costs by rate-regulated entities to the extent that it is probable that those costs will be recovered in future rates. However, the guidance issued by the OEB in the Accounting Procedures Handbook for Electricity Distributors effective January 1, 2012 does not provide specific direction to utilities regarding capitalization of common corporate costs as defined by Hydro One. As a result, certain costs within common corporate costs that are forecasted to be capitalized in the Company's Application may no longer qualify to be capitalized on the adoption of IFRS. Should additional direction be issued by the OEB, these costs may be recorded as regulatory assets in accordance with IFRS 14, reducing the potential impact to future revenue requirements.

In January 2021, the International Accounting Standards Board (IASB) issued Exposure Draft: *Regulatory Assets and Regulatory Liabilities* (Exposure Draft) that is intended to replace IFRS 14. This particular project with the IASB has been ongoing since 2008 with several exposure drafts being issued during that time. Interpretations of these exposure drafts by respondents and IASB members have historically been divergent in respect of key issues. The latest Exposure Draft introduces certain concepts that may result in differences in measurement and disclosure from the current guidance in IFRS 14. The Exposure Draft is open for comment until July 30, 2021 and the final publication date of a standard has not been determined.

The changes to accounting for rate regulated activities proposed by the IASB in its Exposure Draft are different from the current IFRS guidance. Rate regulated utilities that adopt IFRS now may be required to make further significant changes to their accounting policies and processes in the short-term if a new standard is issued. Consequently, waiting until there is certainty on the new IFRS guidance before any final decision is made on whether Hydro One should change its basis of reporting from US GAAP to IFRS might be prudent from a cost/benefit perspective (i.e. to avoid incurring significant costs both for the transition to IFRS using IFRS 14 and for the subsequent transition to a final rate regulated standard which may be duplicative).

Section 1: Potential differences in accounting for common corporate costs under US GAAP and IFRS

Overview and summary

There is no regulatory guideline, statement or source that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes what types of indirect costs should be considered for capitalization.

Canadian utility regulators (including the Ontario Energy Board ("OEB")) and FERC have historically accepted that indirect activities support capital work and, to the extent that there is a causal link to the capital activities, have allowed the associated costs to be allocated to capital. US GAAP and IFRS allow for the capitalization of costs by rate-regulated entities to the extent that it is probable that those costs would be recovered in future rates.

The guidance issued by the OEB in the Accounting Procedures Handbook for Electricity Distributors effective January 1, 2012 does not provide specific direction to utilities regarding capitalization of common corporate Costs as defined by Hydro One. As a result, certain costs within the common corporate Costs capitalized in the Company's Application may no longer qualify to be capitalized on the adoption of IFRS.

Directly attributable costs incurred for activities to bring property, plant or equipment to the condition and location necessary for it to be capable of operating in the manner intended by management may be capitalized in accordance with IAS 16 "*Property, plant and equipment*" (IAS 16). IFRS 14 "*Regulatory Deferral Accounts*" acknowledges the recognition of a regulatory asset for "non-directly-attributable overhead costs that are treated as capital costs for rate regulation purposes".

On transition to IFRS, common corporate costs historically capitalized to Property, plant and equipment (PPE) would likely remain within PPE. Subsequent to the adoption of IFRS, these common corporate costs may be recorded as period expenses to be recovered in the company's annual revenue requirement.

Should accounting processes be amended and updated, there may be specific components within common corporate cost categories that may meet the criteria under IAS 16 to be capitalized to specific capital projects. Furthermore, should additional direction be issued by the OEB, similar to the guidance applicable to entities that report to the OEB under US GAAP, certain of these costs may be recorded as regulatory assets in accordance with IFRS 14.

Overview of accounting

The relevant guidance in respect of capitalizable costs under IAS 16 and the application of IFRS 14 is provided in the table below:

IAS 16 – Property, plant and equipment

P16. The cost of an item of property, plant and equipment comprises:

a. its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
b. any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
c. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

P17. Examples of directly attributable costs are:

a. costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;

b. costs of site preparation;

c. initial delivery and handling costs;

d. installation and assembly costs;

e. costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

f. professional fees.

P18. Examples of costs that are not costs of an item of property, plant and equipment are:

a. costs of opening a new facility;

b. costs of introducing a new product or service (including costs of advertising and promotional activities);

c. costs of conducting business in a new location or with a new class of customer (including costs of staff training); and

d. administration and other general overhead costs.

IFRS 14 – Regulatory deferral accounts

IFRS 14.5 An entity is permitted to apply the requirements of this Standard in its first IFRS financial statements if and only if it:

a. conducts rate-regulated activities; and

b. recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP.

IFRS 14.B3 For the purposes of this Standard, a regulatory deferral account balance is defined as the balance of any expense (or income) account that would not be recognized as an asset or a liability in accordance with other Standards, but that qualifies for deferral because it is included, or is expected to be included, by the rate regulator in establishing the rate(s) that can be charged to customers. Some items of expense (income) may be outside the regulated rate(s) because, for example, the amounts are not expected to be accepted by the rate regulator or because they are not within the scope of the rate regulation. Consequently, such an item is recognized as income or expense as incurred, unless another Standard permits or requires it to be included in the carrying amount of an asset or liability.

IFRS 14.B5 The following are examples of the types of costs that rate regulators might allow in rate-setting decisions and that an entity might, therefore, recognize in regulatory deferral account balances:

a. volume or purchase price variances;

b. costs of approved ‘green energy’ initiatives (in excess of amounts that are capitalized as part of the cost of property, plant and equipment in accordance with IAS 16 Property, Plant and Equipment);

c. non-directly-attributable overhead costs that are treated as capital costs for rate regulation purposes (but are not permitted, in accordance with IAS 16, to be included in the cost of an item of property, plant and equipment);

d. project cancellation costs;

e. storm damage costs; and

f. deemed interest (including amounts allowed for funds that are used during construction that provide the entity with a return on the owner’s equity capital as well as borrowings).

Analysis

Based on the IFRS sections noted above, directly attributable costs incurred for activities to bring the property, plant or equipment to the condition and location necessary for it to be capable of operating in the manner intended by management may be capitalized. Although administrative and other general overhead costs are explicitly prohibited from being capitalized under IAS 16, IFRS 14 acknowledges the recognition of a regulatory asset for "non-directly-attributable overhead costs that are treated as capital costs for rate regulation purposes" (IFRS 14.B5.iii). IAS 16 does not define what types of costs are considered "administrative and other general overhead costs". While the FASB guidance under ASC 360 - "*Property, Plant and Equipment*" ("ASC 360") is not as exhaustive as IAS 16 paragraph 19, the interpretation in practice in this area is largely consistent between the two frameworks and outside the application of ASC 980 - "*Regulated Operations*", administrative and other general overhead costs are not capitalized under US GAAP.

IFRS 14 provides guidance that allows expense (or income) that would not be recognized as an asset or a liability in accordance with other Standards, to qualify for deferral if it is included, or is expected to be included, by the rate regulator in establishing the rate(s) that can be charged (or repaid) to customers in the future.

Consistent with US GAAP guidance under ASC 980, the regulator has a direct impact on how certain costs are accounted for. If a cost supports an underlying capital program, but does not meet the criteria for capitalization under IAS 16, before the application of IFRS 14, the regulator must decide if that cost should be capitalized and borne by customers over the life of the underlying capital projects to match the period during which customers would derive a benefit from it or expensed as a period cost and borne only by current period customers.

Excerpt from Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities

"Overhead Charged to Construction" includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of a reasonable allocation of actual costs. The records supporting the entries for overhead charged to construction costs shall be maintained so as to show the total amount for each element of overhead for the year and the basis of allocation."

Under US GAAP, the guidance above is applicable and supports the capitalization of overhead charges to construction. This guidance is included in Appendix A of the Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities (2007 Handbook).

The Accounting Procedures Handbook for Electricity Distributors effective January 1, 2012 (2012 Handbook) does not contain similar guidance related to overhead charged to construction as described above. The 2012 Handbook would be applicable to Hydro One in the event the Company adopted IFRS for regulatory filing purposes, subject to any further amendments or clarifications issued by the OEB.

There is no explicit guidance issued by the OEB on the treatment of each type of cost that may be incurred to execute a capital investment program and judgment is required by entities reporting under IFRS to determine what components are capitalizable within the guidance outlined above.
Under IFRS, in order for costs to be capitalized, the costs need to be tracked and allocated for each capital project in a manner that can support the assertion that they are "directly attributable" to a given asset or group of assets. Allocations of administrative and general costs as defined under IFRS in IAS 16 typically do not meet the definition of directly attributable costs and therefore cannot be capitalized under IAS 16.

While we have not performed procedures in the scope of this report to quantify the differences between the amounts capitalized under US GAAP versus IFRS, we have identified the following broad steps the Company would need to undertake:

a) determine which categories may require adjustment on adoption of IFRS;

b) determine the significance of a change to the existing processes and procedures in order to determine which tasks within a function can be directly attributable to a capital project (for example, expanding the use of time tracking systems for certain functions where a portion of their time is spent working directly on projects); and

c) determine what the cost/benefit would be for the various functional areas identified that may result in a change based on the guidance in IFRS.

Assuming Hydro One would adopt IFRS and then apply IFRS 14 (before the IASB finalizes its project on rate regulated accounting), IFRS 1 - "*First Time Adoption of International Financial Reporting Standards*" ("IFRS 1") contains an election to allow for previously capitalized costs to remain within PP&E even where they would not qualify for capitalization under IAS 16:

Excerpt from International Financial Reporting Standard 1: First Time Adoption of International Financial Reporting Standards

IFRS 1.D8B - Some entities hold items of property, plant and equipment, right-of-use assets or intangible assets that are used, or were previously used, in operations subject to rate regulation. The carrying amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization in accordance with IFRSs. If this is the case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRSs as deemed cost. If an entity applies this exemption to an item, it need not apply it to all items. At the date of transition to IFRSs, an entity shall test for impairment in accordance with IAS 36 each item for which this exemption is used. For the purposes of this paragraph, operations are subject to rate regulation if they are governed by a framework for establishing the prices that can be charged to customers for goods or services and that framework is subject to oversight and/or approval by a rate regulator (as defined in IFRS 14 Regulatory Deferral Accounts).

However, this election only applies at the IFRS transition date, which is typically the first day of the earliest comparative period presented in the first set of IFRS financial statements (although an earlier date may also be selected). Accordingly, differences after the IFRS transition date would need to be carefully considered.

Changes to existing processes and procedures may include evaluating the capitalization commencement point at which capitalization of individual/unique projects begins, along with tracking, in a more detailed manner, time and costs for the different projects to be able to quantify the amounts that are directly attributable to the construction of the identified asset.

Based on our review of the B&V Report, the following broad categories of Lines of Business would require further evaluation to determine whether they would be able to establish a process to identify and allocate charges directly to a particular capital project:

- costs associated with senior management and governance roles;
- support functions that indirectly provide support to a functioning capital program such as human resources administration costs, workforce acquisition costs, labour relations costs, and talent management, safety meeting and training costs; and
- components of certain support functions such as outsourcing, indigenous relations, external relations, customer service, finance, audit, tax, treasury, business analysis, facilities and real estate, legal, risk, and regulatory affairs.

The total value of these common corporate costs capitalized based on the 2023 forecast was $208 million.

Our observations and conclusions

On transition to IFRS, historical capitalized charges would likely remain within capital assets. Subsequent to the adoption of IFRS, using the 2023 forecasted year, there could be up to $208 million of common corporate costs that would be recorded as period expenses to be recovered in the company's annual revenue requirement. Should accounting processes be amended and updated as described above, there could be specific components within these cost categories that may meet the criteria under IFRS to be directly charged to specific capital projects, thereby reducing the impact to revenue requirement. Furthermore, if the OEB maintains the same ratemaking framework and guidance described in the 2007 Handbook outlined above, agnostic to the accounting framework, we would not expect a significant impact, if any to future revenue requirements in respect of Common Corporate Costs at Hydro One.

Section 2: Other potential differences in accounting between US GAAP and IFRS

Overview and summary

The transition to IFRS from US GAAP would require adjustments in respect of financial statement presentation and updates to processes for tracking information for disclosures. Some of the differences that will need to be considered include:

- Componentization of assets and associated impacts to depreciation
- Accounting for gains and losses on asset retirements (i.e. moving away from group depreciation)
- Presentation and disclosure of regulatory accounts
- Capitalization of interest charges
- Accounting for pensions
- Accounting for leased assets
- Accounting for stock based compensation
- Accounting for provisions and contingencies
- Impairment testing
- Accounting for financial instruments
- The associated income tax effects

The conversion from US GAAP to IFRS would require significant adjustments to presentation and tracking of financial information which could result in additional cost and complexity to Hydro One's financial reporting. Based on our preliminary analysis, except for the treatment of common corporate costs described in Section 1, certain differences may be permitted to be recorded as regulatory accounts under IFRS 14, reducing the impact on the revenue

then presentation aside, we would not expect a significant difference in accounting because IFRS 14 largely aligns the measurement and recognition principles of ASC 980 currently applied by the company.

Analysis

IFRS 14 introduction and applicability
IFRS 14 - "*Regulatory deferral accounts"* is an interim standard on the accounting for regulatory deferral accounts that arise from rate-regulated activities. The objective of the interim standard is to allow entities adopting IFRS to avoid major changes in accounting policy before completion of the broader IASB project to develop an IFRS on rate-regulated activities, described in Section 3 of this report.

IFRS 14 is only applicable to entities that apply IFRS 1 as first-time adopters of IFRS and that conduct rate-regulated activities. It permits such entities, on adoption of IFRS, to continue to apply their previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral accounts. Previous GAAP accounting policies are only applied to balances that are not otherwise covered by specific IFRSs. That is, other specific IFRSs should be applied first, and only any residual balance is accounted for under IFRS 14. If Hydro One is required to adopt IFRS, a fundamental assumption made in the preparation of this report is that Hydro One would also adopt IFRS 14.

Entities are not permitted to change accounting policies to start recognizing regulatory deferral account balances that were not recognized under previous GAAP. Changes to existing policies are restricted and any change must make the financial statements more relevant and no less reliable, as described by IAS 8 - "*Accounting policies, Changes in Accounting Estimates and Errors*" (IAS 8). Entities can, however, recognize new balances that arise as a result of a change in accounting policy, such as on the first-time adoption of IFRS or for changes to IFRS.

As stated above, the differences described below assume that IFRS 14 would be adopted upon transition to IFRS. From our experience, the majority of regulated entities in Canada that have applied IFRS that qualify for the election to apply IFRS 14, have elected to apply the Standard. If IFRS 14 is not adopted, the impacts described below may be more significant.

Modified IFRS (MIFRS) and IFRS 14

Our analysis described throughout this report is based on guidance issued by the International Accounting Standards Board (IASB) and the application of International Financial Reporting Standards. This contemplates the company applying the requirements of IFRS 14, which allows rate regulated utilities reporting under IFRS to establish regulatory deferral accounts in accordance with the accounting policies used for regulatory deferral account balances under the basis of accounting used immediately before adopting IFRS (in Hydro One's case, US GAAP). The differences for accounting purposes identified through the review of externally reported results and the treatment of various items for regulatory purposes outlined in this section were discussed with management. While measurement differences would be identified, we expect the application of IFRS 14 would be largely consistent with the requirements of MIFRS as outlined in the OEB's 2012 Handbook. While presentation and disclosures differences are identified, the application of IFRS 14 would act to reduce revenue requirement differences when reporting in accordance with IFRS.

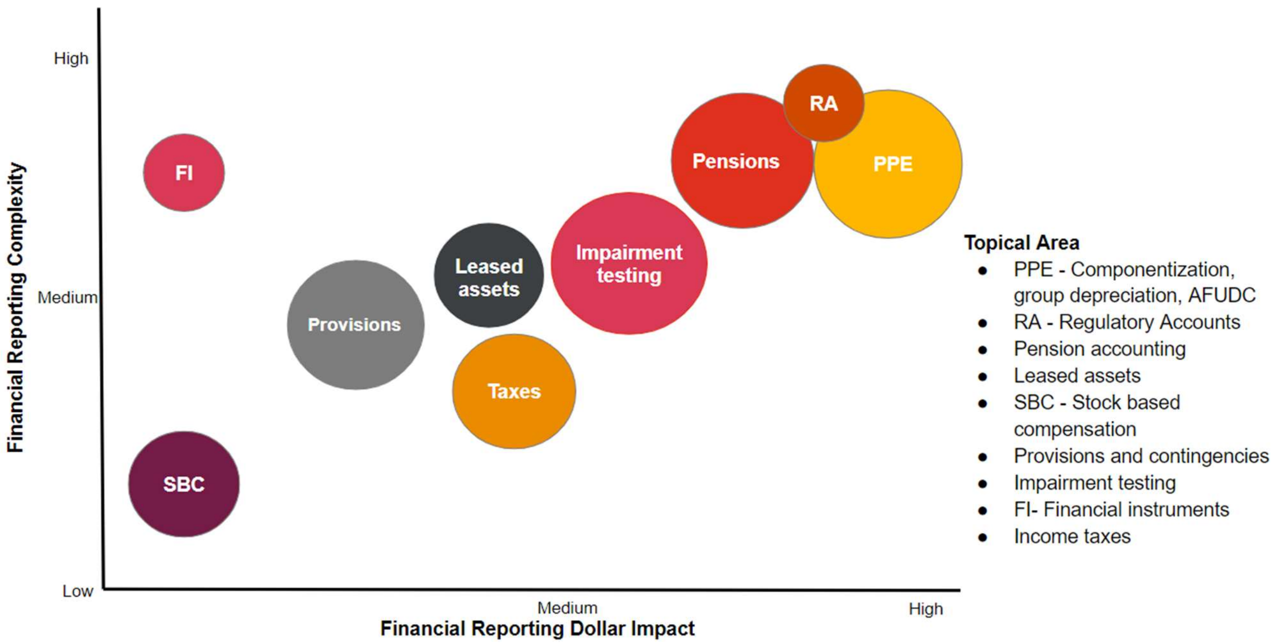
Approach

We evaluated at a high level the impact of transition from US GAAP to IFRS by performing the following:

- obtained and read Hydro One's 2019 Annual Report;
- considered management's analysis of KPMG's *"IFRS compared to US GAAP"* publication, publicly available filings and consolidated financial statements of Hydro One for the year ended December 31, 2019 to identify GAAP differences relevant to Hydro One;
- considered PwC's "*IFRS and US GAAP: similarities and differences"* publication to identify GAAP differences relevant to Hydro One;
- discussed the potential areas of difference from the analyses with Hydro One management; and
- discussed the application of IFRS 14 with management to understand how identified differences may be applied in the company's regulatory filings and how they are consistent with the requirements of MIFRS and guidance that was issued by the OEB to Hydro One on the treatment of various differences.

Summary heat map of key differences between US GAAP and IFRS

The following heat map summarizes key topical areas taking into consideration potential impacts to Hydro One both due to increased financial reporting complexity and to the estimated magnitude of the dollar impact for each identified area of GAAP difference. Each topical area identified has been assessed with consideration given to numerous sub-topics underpinning each conversion topic that ultimately drives the overall complexity.



Potential revenue requirement impacts in year of transition

Through our procedures, we identified differences in accounting measurement, presentation or disclosures in the following key areas as outlined in the summary heat map above:

- Componentization of assets and associated impacts to depreciation
- Accounting for gains and losses on asset retirements (i.e. moving away from group depreciation)
- Presentation and disclosure of regulatory accounts
- Capitalization of interest charges
- Accounting for pensions
- Accounting for leased assets
- Accounting for stock based compensation
- Accounting for provisions and contingencies
- Impairment testing
- Accounting for financial instruments
- The associated income tax effects

We further evaluated the potential impact of these differences on the Company's revenue requirement based on the guidance issued by the OEB in the 2012 Handbook and our discussions with management. For the purposes of this analysis, we evaluated the impact of transition adjustments only in the first year of adoption. The ongoing impact would have to be determined based on future circumstances, along with any additional guidance that is issued by the OEB and the IASB.

1) The following differences were identified between US GAAP and IFRS that may result in an increase in the revenue requirement:

- there is a set limit to the amount of net pension assets under IFRS and IFRS does not reduce the fair value of plan assets by costs to sell resulting in a potential increase to pension expenses to be included in the revenue requirement; and

- capitalization of certain common corporate Costs to property, plant and equipment and intangible assets as outlined in Section 1 of this report would either, a) no longer be able to be capitalized due to a lack of specific OEB guidance, and b) amounts that may be capitalized would be reflected as a regulatory asset. If amounts are no longer eligible for capitalization in rates, this may result in higher period expenses that would be included in the Company's annual revenue requirement.

2) The following differences were identified between US GAAP and IFRS that may result in a decrease in the revenue requirement:

- The company must estimate forfeiture rates when determining share based compensation expense rather than recording forfeitures when the event occurs.

3) The following differences were identified between US GAAP and IFRS that may have an impact on the revenue requirement. Further analysis is required to determine the direction of the impact, or if there are inputs into certain calculations such as interest rates at the time of adoption of IFRS that would be necessary to understand in order to determine whether the impact would be to increase or decrease the revenue requirement. As well, where there may be a difference in measurement or presentation, certain differences may be identified and tracked in a separate regulatory asset or liability account such that there is no impact to the revenue requirements as instructed by the OEB in the 2012 Handbook:

- depreciation rates are required to be estimated on asset components under IFRS which may be lower than the current level of componentization under US GAAP and those reported in the Uniform System of Account (USofA);
- the cost of equity funding may need to be added to the determination of the amount of capitalized interest on the allowance for funds used during construction (AFUDC) - While IFRS 14.B5 (vi) contemplates the recognition of a regulatory asset, we understand the OEB does not issue this guidance and accordingly would have to be tracked separately;
- the expected return on plan assets in respect of employee benefits is calculated using a different method under IFRS than US GAAP which may have an impact on the recognition and measurement of pension expense;
- remeasurement gains or losses for employee benefits (i.e., pension and other post employment benefits) are recognized in other comprehensive income, are not subsequently recorded within profit or loss and may remain in a specific reserve or 'other' reserves within equity;
- employee contributions towards pensions are spread over a period of time rather than reducing the service cost in the period of contribution;
- IFRS does not have the concept of an operating lease (other than through exceptions for certain short term and low value leases) and certain leases may therefore have to be recorded in a manner similar to a capital lease - however for the purposes of the determination of the Company's current revenue requirement, lease costs are recorded on a cash basis so would not be expected to have a significant impact to the future revenue requirement;
- there are differences between IFRS and US GAAP impairment models which may result in the recognition of impairments of property, plant and equipment, goodwill and intangible assets earlier than may be required under US GAAP;
- differences in accounting for certain financial instruments differs between US GAAP and IFRS including accounting for ineffectiveness in a hedging relationship may require measurement and recognition even though the hedge meets the IFRS effectiveness criteria and accounting for the recognition and measurement of "own use" derivative contracts; and
- differences in accounting for income taxes including, but not limited to, deferred tax assets in relation to share-based compensation must be measured based on an estimate of the future tax deduction and are not recognized as the compensation cost is incurred, windfall tax benefits are recorded in equity, interim effective tax rate remeasurement differences and the overall tax impact of any other related adjustments to IFRS.

Disclosures

The disclosure requirements under IFRS are significant and would require data from the Company's system and from internal reporting processes that may not be readily available. These disclosures are not generally required to be prepared for rate making purposes. IFRS generally requires more detailed reconciliations to be performed than US GAAP, for example disclosure of the carrying amounts of PP&E and intangibles at the beginning and at the end of a reporting period as well as a reconciliation of the carrying amount of provisions and contingencies at the beginning and at the end of a reporting period.

A detailed assessment would need to be completed to ensure the noted disclosures, once all differences are identified and quantified, comply with the requirements of IFRS. In certain cases, such as with PP&E, historical data may need to be recreated to achieve compliance.

Our observations and conclusions

While a conversion from US GAAP to IFRS would require numerous significant adjustments to presentation and tracking of financial information to be developed, all of which would introduce cost and complexity to the Company, based on the preliminary analysis described above, many differences may be permitted to be recorded as regulatory accounts under IFRS 14, thereby reducing the potential impact to the revenue requirement. Refer to Section 4 of this report for further discussion on the introduction of cost and complexity to Hydro One.

Section 3: Potential impact of changes to IFRS from the issuance of IASB's Exposure Draft

Overview and summary

The International Accounting Standards Board (IASB) issued a long awaited Exposure Draft: Regulatory Assets and Regulatory Liabilities (Exposure Draft) that is intended, once finalized, to replace IFRS 14. The IASB has been undertaking a project to identify whether, and if so, how, an entity should reflect, in its IFRS financial statements, the impacts of rate regulation since 2008 with several exposure drafts issued. Respondents to previous exposure drafts, as well as IASB members, expressed very divergent, and often strongly held, views relating to the key issues.

The latest Exposure Draft introduces a series of concepts that will likely result in differences in measurement and disclosure of the impact of rate regulated accounting. The proposed model is focused on the recognition of revenue rather than the current cost of service deferral model. Accordingly, significant differences may arise between IFRS 14 and the proposed Exposure Draft.

The Exposure Draft is open for comment to July 30, 2021. The date of a final publication is not known at this time. Depending on the feedback, this Exposure Draft may not go ahead or may change significantly from what was released in January 2021. However, once the final standard is issued it is expected to be applicable for annual reporting periods beginning on or after a date 18–24 months from the date of final publication.

Rate regulated utilities that adopt IFRS before the final Exposure Draft is released may be required to make further significant changes to their accounting policies and processes in the short term if a new standard is issued. Consequently, waiting until there is certainty on the new IFRS guidance before any final decision is made on whether Hydro One should change its basis of reporting from US GAAP to IFRS might be prudent from a cost/benefit perspective (i.e. to avoid incurring significant costs both for the transition to IFRS using IFRS 14 and for the subsequent transition to a final rate regulated standard which may be duplicative).

On January 28, 2021, the IASB issued an Exposure Draft: Regulatory Assets and Regulatory Liabilities, that is intended to replace IFRS 14. The proposed standard introduces a new comprehensive accounting model for rate-regulated companies.

The IASB is proposing that a company report regulatory income and regulatory expense in its income statement, and regulatory assets and regulatory liabilities in its balance sheet. The proposals adopt the principle that a company should reflect the compensation for goods or services supplied as part of its reported financial performance for the period in which it supplies those goods or services.

Based on the Exposure Draft, regulatory assets and liabilities arise when the regulated rate is calculated where some or all of the total allowed compensation for goods or services supplied in one period is charged to customers in a different past or future period. The recognition of regulatory assets and liabilities leads to the recognition of regulatory income and expense. Importantly, the regulatory assets would include a profit element under the proposed standard and not be a pure deferral of costs. That is, the Exposure Draft is based on entitlements to revenues rather than a cost deferral method. Therefore, if finalized it is likely that the standard would result in greater differences between IFRS and regulatory accounting than under US GAAP.

Regulatory assets and liabilities are measured at historical cost, modified for subsequent measurement by using updated estimates of the amount and timing of future cash flows. Uncertainties with respect to the realization of regulatory assets and liabilities would be incorporated in their measurement.

A key concept that is introduced but which is not typical under US GAAP or the current IFRS 14 framework is the requirement to discount the estimated future cash flows of regulatory assets or liabilities by using what the Exposure Draft defines as the regulatory interest rate. After initial recognition, the carrying amount of the regulatory asset or liability is updated at the end of each reporting period to reflect conditions existing at that date. Furthermore, regulatory assets would in some cases include a profit component rather than simply deferring costs.

The Exposure Draft includes extensive changes to the geography of items in the statement of profit or loss. In particular, the Exposure Draft requires an entity to present all regulatory income and expenses as a separate line item immediately below revenue. In the statement of financial position, an entity presents line items for regulatory assets and liabilities. Information about regulatory income, regulatory expense, regulatory assets and regulatory liabilities are disclosed in the notes.

The application of the Exposure Draft has far reaching implications on the recognition, measurement, impairment and derecognition of regulatory deferral accounts. The interpretation is open to comments and subject to change through the Exposure Draft process. The deadline to provide comments on the Exposure Draft to the IASB is July 30, 2021. The expectation is the standard, if finalized in a form consistent with the Exposure Draft, would become effective approximately 18-24 months after being published. However, there remains significant uncertainty about when a final standard will be published and whether it will be consistent with the Exposure Draft.

Section 4: Potential impact of transition to the Company

Overview and summary

A conversion from US GAAP to IFRS introduces complexity, challenges, risks and costs to Hydro One. These additional costs may ultimately be passed on to ratepayers. These challenges include impacts in the broad categories of financial reporting, management reporting, regulatory reporting information systems, organizational change and internal controls. In Hydro One's current environment of customized information systems, continued expansion and upgrade of the existing distribution and transmission network, there would be disruption to the organization in order to upgrade systems and processes to capture the data required to meet the requirement of IFRS on transition and on an ongoing basis. Historical data for certain areas, primarily related to capital assets may not exist and processes may need to be redesigned to capture the additional information required. Adopting IFRS standards that result in a change in measurement may also result in changes to future revenue requirements calculations and may result in rate adjustments to current and future customers that would need to be carefully evaluated.

Background

The company currently reports its financial results and calculates its revenue requirement in accordance with US GAAP, supplemented with guidance issued by the OEB in the 2007 Handbook. US GAAP is the accounting standard used to measure and record financial results for internal management reporting, external financial reporting to shareholders and debtholders and to the OEB in the USofA (collectively referred to as "the stakeholders"). The Company has been reporting to its shareholders and debtholders under US GAAP since 2012 in accordance with an exemptive relief issued by the Ontario Securities Commission, along with established contractual agreements and in doing so has structured and customized its processes, people and technology to report its results in accordance with US GAAP to all of its stakeholders.

Extensive efforts in customization of organizational structures, systems and processes along with a longstanding understanding of financial results measured in accordance with US GAAP has been established by the organization. A transition from US GAAP to IFRS is a complex and costly undertaking for any organization. While there are alternatives and expedients available to entities transitioning to IFRS, and assumptions over complexity may vary based on the particular alternatives and expedients selected, disruption is nonetheless introduced into the organization in each case. At a minimum, the table below provides a non-exhaustive list of the numerous workstreams and key activities that would have to be executed in order for Hydro One to convert from US GAAP to IFRS:

Workstream	Underlying activities
Organizational change management	• Determine structure of project team (e.g., project leads, steering committee, cadence and form of project updates to board and audit committee, etc.) • Project planning, scoping and budgeting activities • Consideration over required resources and capacity, hire external consultants to assist • Establish and agree upon timelines and milestones • Develop mechanisms for tracking progress against established milestones • Plan for engagement of auditors
Financial, regulatory and management reporting	• Identification of GAAP differences and development of roadmap to address each difference • Preparation, review and approval of GAAP analyses, revisions and/or development of accounting policies under the new framework

Workstream	Underlying activities
	• Preparation review and approval of revised and/or new internal controls and process documentation • Consideration over potential engagement of experts (i.e. Capitalization and depreciation studies, actuarial reports, valuation studies, analysis over regulatory implications, legal review of significant contracts etc.) • Modifications to/development of financial reporting templates for IFRS • Modifications to/development of new financial statement disclosures and presentation under IFRS • Planning and execution of changes to key information systems • Performance of tax analysis including statutory and regulatory reporting implications • Audit of the conversion adjustments and revised financial statement presentation • Assessment over impacts to management reporting
Workstream	• **Underlying activities**
Information systems, controls and external stakeholder alignment	• Stakeholder communication and training • Identification of current system challenges and potential roadblocks • Assessment over impacts on current business processes (i.e., treasury, procurement, risk management etc.) • Assessment over impacts to key performance indicators

There are two primary scenarios that we identify for the Company in the event that an IFRS conversation would be required for the determination of the revenue requirement and ongoing regulatory reporting by the OEB. As securities regulations and the Exposure Draft discussed in Section 3 evolve, the number of scenarios may differ. However, the two primary alternatives include:

1) transitioning from US GAAP to IFRS for all internal and external reporting; or
2) maintaining external financial reporting for the consolidated Hydro One group in accordance with US GAAP, transitioning only the revenue requirement and ongoing regulatory reported results to IFRS for the OEB.

Both alternatives present risks and challenges as further outlined in this section. In either scenario, the Company would have to maintain an IFRS accounting ledger of financial results in their enterprise resource planning system (ERP), and be able to operationalize the changes that are required to processes, people and technology in order to capture the required data and account for the results, while ensuring adequate controls are in place to prevent misstatement of financial results.

Approach

We evaluated areas of impact with management in support of our overall observations and conclusions and based on certain assumptions including, but not limited to:

- Hydro One would be transitioning to IFRS based on the guidance issued by the IASB as of the date of this report. In particular, we have not taken into consideration the potential impacts of the recently published Exposure Draft on Regulatory Assets and Regulatory Liabilities described in Section 3.
- Hydro One would be transitioning to IFRS using its current information systems and processes. While in the process of performing a transition to IFRS, the Company may determine that alternative technology or upgrades would be necessary to capture required data - however we did not consider this in the scope of this report.

In order to identify and describe some of the potential risks and challenges, we used the results of our US GAAP to IFRS differences exercise described in Section 2. We met with management of the Company and gathered an understanding of current key systems in place and discussed the extent of complexity and disruption certain changes in accounting may have across the dimension of people, processes and technology.

The results of these discussions with management are outlined below. The observations identified below are summarized in the key areas and not considered to be an exhaustive list of impacts that may be identified in the event the Company or others were to perform additional procedures.

We summarize the key impact areas from a conversion to IFRS and highlight areas of significant risk and complexity that would be introduced to the organization should a conversion to IFRS be required. It is important to note that underpinning all impacted areas of the business, is the overall disruption and change impact to both shareholders and employees at all levels of the organization.

Financial reporting
On transition to IFRS, differences between US GAAP and IFRS would need to be identified, quantified and adjusted. While we have performed an analysis based on the externally reported results, to finalize the identified differences, evaluated accounting alternatives, disclosure requirements, quantify the differences and re-organize people, processes and technology in order to operationalize reporting internally and externally in accordance with IFRS, in itself is a significant undertaking for an organization the size and complexity of Hydro One. In addition to the complexity and cost associated with the identification of GAAP differences and adjustments, key financial reporting processes would need to be updated and operational and financial reporting controls would need to be implemented in order to effectively manage the risk associated with reporting under a new framework.

Management reporting
Management reporting processes for Hydro One are complex and include a high degree of customization at various levels within the organization. Management reporting is performed at various levels that are below what is reported externally and for regulatory purposes to establish adequate reviews of results. Of particular significance is the difference in financial reporting requirements between the Distribution and Transmission business and the various sub functions and groups that operate within these groups. This means changes to the underlying data and to the flow of data that would be required in order to report under IFRS, both for external reporting and operational reporting purposes - the latter of which would have far reaching impacts on management reporting processes.

Consideration would need to be given for any changes made to the chart of accounts as a result of a conversion to IFRS. Hydro One has numerous internal and regulatory reporting requirements that are dependent upon the current chart of accounts. Therefore, any changes would need to be carefully examined in order to ensure that the updates are captured across all internal and external reporting requirements, in addition to the financial statements.

In addition, key KPIs could potentially be impacted by a GAAP conversion. This may have significant impacts on how certain KPIs are measured, tracked, reported and evaluated. Analysis would be required to determine the magnitude of impact a GAAP conversion would have on Hydro One's KPIs and performance incentives used for both internal and external reporting purposes.

Regulatory reporting
Currently, all SAP accounts are mapped to the USofA that is used for regulatory reporting purposes with the OEB. Any financial reporting change from a GAAP transition has the potential to change the purpose of an SAP account and would require review of the USofA mapping to ensure it is compliant with regulatory requirements. There could also be a potential for an increase in the amount of manual adjustments that is required to be made in the USofA system if the GAAP difference has a different treatment under regulatory standards.

In addition, to the extent that there are changes to Hydro One's data and measurement under IFRS, the Regulator and intervenors will require time and resources to understand these changes and to develop a process for meaningful comparison to past performance.

Information systems

Impacts on key system processes	
Current observations	**Required changes/impacts**
Current observations	**Required changes/impacts**
There are 2 accounting ledgers currently in use in the Company's financial system - US GAAP and USofA.	

Current observations	Required changes/impacts
Data and processes related to historical retirements and prospective retirements of assets needs to be captured and accounted for in accordance with IFRS.	Data creation may be needed or another solution to augment the Company's historical data in order to meet the requirements of IFRS. The current processes would need to be redesigned, particularly in respect of retirement of capital assets, to ensure that the retirements are appropriately captured and accounted for under IFRS.
Under US GAAP, certain leases are accounted for as operating leases. For revenue requirement and regulatory purposes, we understand from management that leases are treated as operating leases, however an adoption of IFRS would necessitate a change to the measurement and tracking of the difference between operating and capital leases.	A transition to IFRS would likely require existing operating leases to be recorded as right of use assets along with their associated liabilities on the balance sheet - and the processes, financial results and internal and external reporting need to be updated to capture and account for the information in accordance with US GAAP.
Current observations	**Required changes/impacts**
The current tax process relies on the current system data and processes - for each of the identified differences, in particular the adjustments related to capital assets would need to be calculated and tracked in order to determine current and deferred taxes.	Any financial reporting changes from a GAAP transition has the potential to change the SAP system information used by the tax function. This would require a reconfiguration of how data is extracted from current systems as well as the tax accounting models that are used by the Company.
Accounting for pensions is complex and includes the use of external experts to support management in the preparation and quantification of pension charges, assets and liabilities.	The Company would have to reconfigure its processes to capture the required data and adjust the prospective financial results and process to capture the differences identified.

While the table above describes certain specific areas of complexity in the information systems environment, the items identified above are not exhaustive and only touch on the more significant areas that would be required. What this list highlights is that in an organization as large and complex as Hydro One, there would be a significant impact from a systems perspective should the Company be required to convert to IFRS. This could introduce a high level of complexity, risk and cost to the organization.

Organizational change

An important dimension of transitioning to IFRS is the overall disruption and change impact to shareholders, stakeholder and employees. In order to minimize the potentially negative impacts of organizational change, resources would need to be deployed to ensure that those affected understand why the changes are taking place and why they are necessary. A steering committee would need to be formed with appropriate leadership across various levels of the organization to effectively plan for the change prior to implementation.

Of equal importance to the technical aspects described above in respect of implementing a GAAP conversion of this magnitude is stakeholder communication, education and training. Each GAAP conversion impact would result in changes to processes and controls. For example, under IFRS there would be a fundamental change required to the Company's planning process in order to accommodate planning its capital program at the component level. Technical implementation considerations alone may not result in a successful implementation of a new financial reporting framework and the organizational and people impact of the change would need to be carefully considered throughout the organization adding risk, complexity and cost.

In addition to the changes to people and process, contracts with employees, unions, creditors, suppliers and others would need to be closely evaluated to determine whether any changes to measurement or disclosure would require a change to contractual terms. Changes to the host of existing contracts may be complex and depending on the extent of change may be costly and time consuming to execute.

For external stakeholders, at a minimum, Hydro One would need to prepare formal and regular communications on planning, status, costs etc. with its board of directors, audit committee, executives, shareholders, debtholders and across the functions of the organization, in addition to the OEB.

Internal controls

If Hydro One is required to convert to IFRS, the organization would need to perform an assessment of its internal control environment and update its internal controls to ensure both the accuracy of the IFRS adjustments and the completeness and accuracy of any additional disclosures that were not required under US GAAP. An assessment would need to be performed to identify all impacted controls - both financial and operational controls - as a result of changes to people, systems and processes. Where necessary, revisions to existing controls and additional controls that would be required, including both manual and automated controls, would need to be evaluated. All revisions to existing internal controls and any new internal controls would need to be documented, tested, reviewed and approved by the Company's management, internal audit group and the Company's external auditors.

Estimated timeline for a transition of this complexity and magnitude

Based on the procedures outlined and our discussions with management, in order to perform a transition to IFRS under the standards effective as of the date of this report (i.e., not contemplating the impact of the Exposure Draft outlined in Section 3) while maintaining control and focus on the operations of the regulated business, including operationalizing the adjustments - we estimate it would take the Company between 12-24 months to fully adopt IFRS and operationalize revised processes, people and technology across the organization.

This estimated timeframe does not contemplate any competing priorities or additional challenges that may be identified during a data gathering stage of a transition to IFRS, particularly in the area of capital assets across the distribution and transmission business.

Potential impact to ratepayers

The cost of a transition to IFRS would likely be recoverable from ratepayers in the Company's revenue requirement. We have not been engaged to estimate the total cost of this transition, however given the technically complex systems, processes and multiple business units involved (i.e., Tx and Dx), based on our experience, we believe the cost would not be inconsequential to the revenue requirement. Depending on the alternative selected by the Company described previously - i.e., adopt for regulatory reporting purposes, or transition the entire organization - there would be ongoing maintenance costs that may have to be added to the revenue requirement.

While we have not quantified the impact of the identified areas of potential difference, changes in measurement stemming from a conversion to IFRS may result in a change in the revenue requirement as well as incurring significant costs for the transition. Once quantified, the impact would have to be carefully studied to determine the best course of action to recover the costs and manage any potential rate shock to customers.

Our observations

Hydro One is one of Canada's largest regulated utilities and is responsible for much of the distribution and transmission of electricity in Ontario. Like any regulated utility, the Company is inherently complex and is supported by a customized structure of systems, processes and people. Because of the scale and complexity of the capital program across the Transmission and Distribution business in particular, support from the functional areas of the organization would be required to successfully execute a transition from US GAAP to IFRS.

In addition, this highly complex IFRS conversion would need to be layered onto the organization while it is executing an extensive capital program to upgrade and expand the existing electricity network, which is an initiative that requires the attention and focus across the organization to execute effectively. Therefore, given the level of support that will be required from the functional areas of the organization to execute the IFRS conversion coupled with the resource requirements of the capital program upgrade, the introduction of a conversion to IFRS will introduce costs and risk to the organization, along with the management of any changes to the revenue requirement, the impact of which would require careful examination.

Appendix A – Qualifications

Philip Hagel

Philip is a utilities specialist partner with over 15 years working with utility clients in Canada, the US and the UK. He joined PricewaterhouseCoopers in Toronto, Ontario in 2006 after graduating from Brock University with a Bachelor of Accounting degree, subsequently obtaining his Chartered Accountant qualification in 2009. Philip has worked on a variety of regulated and unregulated energy businesses in Canada and the United States, including leading a North American team on the audit of a Fortune 500 multinational energy company.

Philip oversees audit and advisory services to several Canadian utilities. He has a wide range of international experience in leading large and complex external audit assignments, IFRS and US GAAP conversion projects, due diligence and transaction services, stock exchange listings and advisory services.

Philip is a Partner of PricewaterhouseCoopers LLP, based in our Toronto office whose address is 18 York Street, Suite 2600 Toronto, Ontario, M5J 0B2.

Philip as well as other PwC personnel working under his supervision and direction, have read and analyzed supporting documentation and information relevant to the issues on this engagement. He has been assisted by several other PwC professionals, including Eric Clarke with applicable regulated utility knowledge and experience.

HYDRO ONE TRANSMISSION AND DISTRIBUTION FINANCIAL STATEMENTS - HISTORICAL YEARS

Included in this exhibit are the historical Transmission Financial Statements:

- Attachment 1: 2018 and 2019 Audited Transmission Financial Statements
- Attachment 2: 2019 and 2020 Audited Transmission Financial Statements

Included in this exhibit are the historical Distribution Financial Statements:

- Attachment 3: 2018 and 2019 Audited Distribution Financial Statements
- Attachment 4: 2019 and 2020 Audited Distribution Financial Statements

This page left blank intentionally.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2019
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "carve-out financial statements").

In our opinion, the accompanying carve-out financial statements as at and for the year ended December 31, 2019 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these carve-out financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Preparation

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.

The purpose of the carve-out financial statements is to meet Hydro One Networks Inc.'s obligation to the Ontario Energy Board. As a result, these carve-out financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Carve-Out Financial Statements

Management is responsible for the preparation of the carve-out financial statements in accordance with the financial reporting framework described in Note 2 in the carve-out financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements

Our objectives are to obtain reasonable assurance about whether the carve-out financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the carve-out financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the carve-out financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

We have served as the Company's auditor since 2008

Toronto, Canada
April 22, 2020

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2019 and 2018

Year ended December 31 *(millions of Canadian dollars)*	2019	2018
Revenues		
Transmission tariff *(Note 23)*	1,547	1,584
Other	47	39
	1,594	1,623
Costs		
Operation, maintenance and administration *(Note 23)*	371	420
Depreciation, amortization and asset removal costs *(Note 4)*	444	418
	815	838
Income before financing charges and income tax expense	**779**	**785**
Financing charges *(Notes 5, 23)*	266	239
Income before income tax expense	**513**	**546**
Income tax expense *(Note 6)*	11	62
Net income	**502**	**484**
Other comprehensive income	—	—
Comprehensive income	**502**	**484**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2019 and 2018

December 31 *(millions of Canadian dollars)*	2019	2018
Assets		
Current assets:		
Accounts receivable	83	36
Due from related parties *(Note 23)*	134	127
Other current assets *(Note 7)*	46	39
	263	202
Property, plant and equipment *(Note 8)*	12,725	12,269
Other long-term assets:		
Regulatory assets *(Note 10)*	1,054	838
Intangible assets *(Note 9)*	171	138
Other assets *(Notes 11, 20)*	37	1
	1,262	977
Total assets	**14,250**	**13,448**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	849	897
Long-term debt payable within one year *(Notes 14, 15, 23)*	180	437
Accounts payable and other current liabilities *(Note 12)*	251	246
Due to related parties *(Note 23)*	60	64
	1,340	1,644
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	6,344	5,637
Deferred income tax liabilities *(Note 6)*	817	638
Regulatory liabilities *(Note 10)*	37	102
Other long-term liabilities *(Note 13)*	846	698
	8,044	7,075
Total liabilities	**9,384**	**8,719**
Contingencies and Commitments (Notes 25, 26)		
Subsequent Events (Note 27)		
Excess of assets over liabilities *(Notes 16, 21)*	4,866	4,729
Total liabilities and excess of assets over liabilities	**14,250**	**13,448**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Russel Robertson
Chair, Audit Committee

Mark Poweska
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2019 and 2018

Year ended December 31 *(millions of Canadian dollars)*	2019	2018
Operating activities		
Net income	502	484
Environmental expenditures	(6)	(6)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	398	380
Regulatory assets and liabilities	(9)	(18)
Deferred income tax expense (recovery)	4	(1)
Other	(9)	11
Changes in non-cash balances related to operations *(Note 24)*	(31)	8
Net cash from operating activities	**849**	**858**
Financing activities		
Long-term debt issued	885	988
Long-term debt repaid	(437)	(413)
Payments to finance dividends and return on stated capital	(230)	(213)
Other	(4)	(4)
Net cash from financing activities	**214**	**358**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(963)	(918)
Intangible assets	(57)	(45)
Capital contributions received *(Note 23)*	3	7
Other	2	2
Net cash used in investing activities	**(1,015)**	**(954)**
Net change in inter-company demand facility	48	262
Inter-company demand facility, beginning of year	(897)	(1,159)
Inter-company demand facility, end of year	**(849)**	**(897)**

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 Company's 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).

Rate Setting

On March 7, 2019, the OEB issued a decision on its reconsideration of its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirement dated September 28, 2017 (Original Decision) with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from the transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to tax payments under the federal and provincial tax regimes which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. See Note 10 - Regulatory Assets and Liabilities for additional information. On October 26, 2018, Hydro One Networks filed a one-year inflation-based application with the OEB for 2019 transmission revenue requirement. On April 25, 2019, the OEB issued its decision on Hydro One Networks' 2019 transmission rate application, and set the revenue index at 1.4% on a final basis effective May 1, 2019.

On March 21, 2019, Hydro One Networks filed a three-year Custom Incentive Rate application with the OEB for 2020-2022 transmission rates. On June 19, 2019, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments. The hearing began on October 21, 2019, and concluded on November 4, 2019. The OEB decision is pending.

On December 10, 2019, the OEB approved Hydro One Networks' 2019 transmission revenue requirement and charges as interim effective January 1, 2020 until the new transmission revenue requirement and charges are approved by the 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).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2019 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Transmission Business. 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 Transmission Business. As a result of this basis of preparation, 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. These Financial Statements include deferred taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. 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 22, 2020, 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 27 - 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.

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 prospectively from the date the assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Revenue Recognition

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTR) which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are 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

The Transmission Business early-adopted Accounting Standard Update (ASU) 2016-13 *Financial Instruments - Credit Losses* (along with related ASUs as disclosed in Note 3 - New Accounting Pronouncements) with a transition date of January 1, 2019 using the modified retrospective method. Upon adoption, there was no material impact to the Financial Statements, and no adjustments were made to prior period financial statements.

Trade accounts receivable represent 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.

For other accounts receivables, the Transmission Business estimates the current lifetime expected credit losses by applying internally developed loss rates to all outstanding other accounts receivables by aging category. Loss rates applied to the other accounts receivables balances are based on historical overdue balances, customer payments and write-offs. Other accounts receivables 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.

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 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.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including 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 recognizes deferred income taxes associated with its regulated operations and records offsetting regulatory assets and liabilities for the deferred income taxes that are expected to be recovered or refunded in future regulated rates charged to customers.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

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, and information technology. 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 the 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	22 years	1% - 20%	5%
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, 2019 and 2018, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Transmission Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred 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 (i) held-to-maturity, (ii) loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) 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 Transmission Business 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.

The Transmission Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Transmission Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Transmission Business' risk management policy disclosed in Note 15 - 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, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. 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 (i) 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, (ii) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period, and (iii) 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 that required bifurcation at December 31, 2019 or 2018.

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 (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO 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 PBO of the plan, an asset is recognized equal to the net overfunded PBO. 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 (DC 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 (OM&A) 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.

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.

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 or liability as the case may be, 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 or liability as the case may be, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited 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 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 awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the 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 (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. 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. This uncertainty is incorporated in the fair value measurement of the obligation.

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. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. 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.

Leases

Effective January 1, 2019, the Company adopted Accounting Standards Codification (ASC) 842 - *Leases* using the modified retrospective transition approach using the effective date of January 1, 2019, as its date of initial application. In the Company's transition to ASC 842, the Company elected the package of practical expedients and the land easement practical expedient. As a result, a Right-of-Use (ROU) asset and a corresponding lease obligation of approximately $12 million was recognized on the balance sheet at January 1, 2019, and no adjustments were made to prior period financial statement amounts. There was no material impact to the statement of operations and comprehensive income. On adoption, the Company did not identify any finance leases.

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding ROU asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets are calculated as the difference between the lease expense and the accretion of interest, which is calculated on the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a re-measurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present ASCs and ASUs issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASC 842	February 2016 - January 2019	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	Hydro One adopted ASC 842 on January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption. The Company has included the disclosure requirements of ASC 842 in Note 20 to the Financial Statements.
ASU 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 presentation of hedge results.	January 1, 2019	No impact upon adoption
ASU 2018-07	June 2018	Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees.	January 1, 2019	No impact upon adoption
ASU 2018-15	August 2018	The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment.	January 1, 2019	Hydro One early-adopted this ASU with a transition date of January 1, 2019. The ASU was applied prospectively and there was no material impact upon adoption.
ASU 2016-13 2018-19 2019-04 2019-05 2019-11	June 2016 - November 2019	The amendments provide users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.	January 1, 2019	Hydro One early-adopted these ASUs with a transition date of January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
ASU 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	No impact upon adoption
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	Under assessment
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are not applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2019	2018
Depreciation of property, plant and equipment	363	350
Amortization of intangible assets	29	24
Amortization of regulatory assets	6	6
Depreciation and amortization	398	380
Asset removal costs	46	38
	444	418

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2019	2018
Interest on long-term debt *(Note 23)*	284	259
Interest on inter-company demand facility *(Note 23)*	13	16
Other	10	10
Less: Interest capitalized on construction and development in progress	(41)	(46)
	266	239

6. INCOME TAXES

As a rate regulated utility business, the Transmission Business' effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. 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)*	2019	2018
Income before income tax expense	513	546
Income tax expense at statutory rate of 26.5% (2018 - 26.5%)	136	145
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization[1]	(64)	(43)
Impact of tax deductions from deferred tax asset sharing[2]	(26)	—
Overheads capitalized for accounting but deducted for tax purposes	(12)	(12)
Interest capitalized for accounting but deducted for tax purposes	(11)	(12)
Pension and post-retirement benefit contributions in excess of expense	(8)	(7)
Environmental expenditures	(1)	(2)
Other	(4)	(8)
Net temporary differences	(126)	(84)
Net permanent differences	1	1
Total income tax expense	11	62
Effective income tax rate	2.1%	11.4%

[1] Included in current period's amount is the accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.
[2] Impact of tax deductions from deferred tax sharing represents the OEB's prescribed allocation to ratepayers of the net deferred tax asset that originated from the transition from the payments in lieu of tax regime under the *Electricity Act 1998* (Ontario) to tax payments under the federal and provincial tax regime.

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2019	2018
Current income tax expense	7	63
Deferred income tax expense (recovery)	4	(1)
Total income tax expense	11	62

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities that are 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, 2019 and 2018, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2019	2018
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,055)	(875)
Regulatory amounts that are not recognized for tax purposes	(45)	(1)
Post-retirement and post-employment benefits expense in excess of cash payments	273	226
Environmental expenditures	22	25
Other	(9)	(10)
	(814)	(635)
Less: valuation allowance	(3)	(3)
Net deferred income tax liabilities[1]	(817)	(638)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term liabilities.

7. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2019	2018
Regulatory assets *(Note 10)*	18	11
Prepaid expenses and other assets	16	16
Materials and supplies	12	12
	46	39

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	16,625	5,658	709	11,676
Communication	993	741	38	290
Administration and service	582	322	23	283
Easements	540	64	—	476
	18,740	6,785	770	12,725

[1] Includes future use assets totalling $97 million.

On September 18, 2019, transmission assets related to a new 230 kV transmission line (Niagara Line) in the Niagara region totalling $119 million were transferred from Hydro One Networks to Niagara Reinforcement LP (NRLP), a subsidiary of Hydro One. See Note 16 - Capital Management.

December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,856	5,407	759	11,208
Communication	968	690	33	311
Administration and service	558	306	33	285
Easements	530	65	—	465
	17,912	6,468	825	12,269

[1] Includes future use assets totalling $97 million.

Financing charges capitalized on property, plant and equipment under construction were $39 million in 2019 (2018 - $45 million).

9. INTANGIBLE ASSETS

December 31, 2019 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	359	216	21	164
Other	12	5	—	7
	371	221	21	171

December 31, 2018 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	297	193	29	133
Other	8	3	—	5
	305	196	29	138

Financing charges capitalized to intangible assets under development were $2 million in 2019 (2018 - $1 million). The estimated annual amortization expense for intangible assets is as follows: 2020 - $20 million; 2021 - $19 million; 2022 - $18 million; 2023 - $17 million; and 2024 - $15 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)*	2019	2018
Regulatory assets:		
Deferred income tax regulatory asset	892	731
Environmental	62	69
Post-retirement and post-employment benefits	47	—
Post-retirement and post-employment benefits non-service cost	44	23
Stock-based compensation	23	21
Other	4	5
Total regulatory assets	1,072	849
Less: current portion	(18)	(11)
	1,054	838
Regulatory liabilities:		
Deferred income tax regulatory liability	32	47
Tax rule changes variance	20	—
External revenue variance	6	26
Pension cost differential	9	17
Post-retirement and post-employment benefits	—	56
Other	2	4
Total regulatory liabilities	69	150
Less: current portion	(32)	(48)
	37	102

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 2019 income tax expense would have been higher by approximately $129 million (2018 - lower by $359 million).

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited 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 a portion of Hydro One Networks' transmission deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. As a result, as at December 31, 2018, the Transmission Business recognized an impairment charge of the deferred income tax regulatory asset of $558 million, an increase in deferred income tax regulatory liability of $47 million, and a decrease in the foregone revenue deferral regulatory asset of $68 million. The regulatory balances relating to deferred tax asset sharing will continue to decrease as the tax savings are shared with ratepayers. Notwithstanding the recognition of the effects of the decision in the financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's deferred tax benefit decision. The appeal was heard on November 21, 2019 and a decision is pending.

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. In 2019, the environmental regulatory asset decreased by $4 million (2018 - $6 million) to reflect related changes in the Transmission Business' PCB and LAR environmental liabilities. 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, 2019 OM&A expenses would have been lower by $4 million (2018 - $6 million). In addition, 2019 amortization expense would have been lower by $6 million (2018 - $6 million), and 2019 financing charges would have been higher by $3 million (2018 - $3 million).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. 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 the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2019 OCI would have been lower by $103 million (2018 - higher by $73 million).

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks applied to the OEB for a regulatory asset account to record the components other than service costs relating to its post-retirement and post-employment benefits that would have previously been capitalized to property, plant and equipment and intangible assets prior to adoption of ASU 2017-07. In May 2018, the OEB approved the regulatory asset account for the Transmission Business. The Transmission Business has recorded the components other than service costs relating to its post-retirement and post-employment benefits that would have been capitalized to property, plant and equipment and intangible assets, in the Post-Retirement and Post-Employment Benefits Non-Service Cost regulatory asset.

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, there would be no material impact to OM&A expenses in 2019 and 2018. 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.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting Hydro One Networks to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028. The Budgets measures enacted in the second quarter of 2019 required the Transmission Business to refund the tax benefits related to the accelerated depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the accelerated tax; therefore, the revenue subject to refund cannot be recognized.

External Revenue Variance

The external revenue variance account balance reflects the difference between actual export service revenue and external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which was returned to customers over a two-year period ended December 31, 2018. The balance as at December 31, 2018, including accrued interest, was requested for disposition in the 2020-2022 transmission rate application.

Pension Cost Differential

Variances between the pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Transmission Business are recognized as a regulatory asset or regulatory liability, as the case may be. The Transmission Business' pension cost differential account balance as at December 31, 2018, including accrued interest, was requested for disposition in the 2020-2022 transmission rate application. In the absence of rate-regulated accounting, 2019 revenue would have been higher by $5 million (2018 - $4 million).

11. OTHER LONG-TERM ASSETS

December 31 *(millions of dollars)*	2019	2018
Right-of-Use assets *(Notes 3, 20)*	35	—
Other	2	1
	37	1

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2019	2018
Accrued liabilities	44	31
Accounts payable	109	110
Accrued interest *(Note 23)*	62	57
Regulatory liabilities *(Note 10)*	32	48
Lease obligations *(Note 20)*	4	—
	251	246

13. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2019	2018
Post-retirement and post-employment benefit liability *(Note 17)*	732	602
Environmental liabilities *(Note 18)*	49	62
Lease obligations *(Note 20)*	33	—
Long-term inter-company payable *(Note 23)*	18	17
Long-term accounts payable and other liabilities	9	12
Asset retirement obligations *(Note 19)*	5	5
	846	698

14. 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, 2019 and 2018:

December 31 *(millions of dollars)*	2019	2018
Long-term debt	6,544	6,096
Add: Net unamortized debt premiums	5	6
Add: Unrealized mark-to-market gain[1]	1	(3)
Less: Deferred debt issuance costs	(26)	(25)
Less: Long-term debt payable within one year	(180)	(437)
Long-term debt	6,344	5,637

[1] The unrealized mark-to-market loss relates to $300 million notes due in 2021 (2018 - unrealized mark-to-market net gain also related to $300 million notes due in 2019). The unrealized mark-to-market loss is offset by a $1 million unrealized mark-to-market gain (2018 - $3 million net loss) on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2019, Hydro One issued $1,500 million (2018 - $1,400 million) of long-term debt under its MTN Program, all of which was mirrored down to Hydro One Networks, and $885 million was allocated to the Transmission Business.

In 2019, Hydro One repaid $728 million (2018 - $750 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $728 million (2018 - $750 million) to Hydro One, of which $437 million (2018 - $413 million) was allocated to the Transmission Business.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

Years	Long-Term Debt Principal Repayments *(millions of dollars)*	Interest Payments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
2020	180	282	4.4
2021	550	271	2.5
2022	319	259	3.2
2023	—	253	—
2024	413	248	2.8
	1,462	1,313	3.0
2025-2029	788	1,148	3.2
2030 and thereafter	4,294	2,550	5.1
	6,544	5,011	4.4

15. 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 Transmission Business 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, 2019 and 2018, 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, 2019 and 2018 are as follows:

December 31 *(millions of dollars)*	2019 Carrying Value	2019 Fair Value	2018 Carrying Value	2018 Fair Value
$300 million notes due 2019	—	—	297	297
$300 million notes due 2021	301	301	300	300
Other notes and debentures	6,223	6,984	5,477	6,049
Long-term debt, including current portion	6,524	7,285	6,074	6,646

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, 2019, the Transmission Business' share of the Company's derivative instruments included $300 million (2018 - $600 million) interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was approximately 5% (2018 - 10%) of its total long-term debt. At December 31, 2019, the Transmission Business' interest-rate swaps designated as fair value hedges were as follows:

- a $300 million fixed-to-floating interest-rate swap agreement to convert the $300 million notes maturing June 25, 2021 into three-month variable rate debt.

At December 31, 2019 and 2018, 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, 2019 and 2018 is as follows:

December 31, 2019 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments - fair value hedges (interest-rate swaps)[1]	1	1	—	1	—
	1	1	—	1	—
Liabilities:					
Long-term debt, including current portion	6,524	7,285	—	7,285	—
	6,524	7,285	—	7,285	—

[1] Derivative assets are included in other long-term assets on the balance sheets.

December 31, 2018 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	6,074	6,646	—	6,646	—
Derivative instruments - fair value hedges (interest-rate swaps)[1]	3	3	—	3	—
	6,077	6,649	0	6,649	—

[1] Derivative liabilities are included in other long-term liabilities on the balance sheets.

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, 2019 or 2018.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

<u>Market Risk</u>

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 may utilize interest-rate swaps 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, 2019 and 2018.

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 net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2019 and 2018 were 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, 2019 and 2018, 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, 2019 and 2018, there was no material accounts receivable balance due from any single customer.

The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2019, approximately 5% (2018 - 11%) 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 (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both 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, 2019 and 2018, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2019, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with three 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 operating 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.

16. 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, 2019 and 2018, the Transmission Business' capital structure was as follows:

December 31 *(millions of dollars)*	2019	2018
Long-term debt payable within one year	180	437
Inter-company demand facility	849	897
	1,029	1,334
Long-term debt	6,344	5,637
Excess of assets over liabilities	4,866	4,729
Total capital	12,239	11,700

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2019 and 2018:

Year ended December 31 *(millions of dollars)*	2019	2018
Excess of assets over liabilities - beginning	4,729	4,458
Net income	502	484
Payments to Hydro One to finance dividends and return of stated capital	(230)	(213)
Other[1 2]	(135)	—
Excess of assets over liabilities - ending	4,866	4,729

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Transmission Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Transmission Business, resulting in an impact to excess of assets over liabilities.

[2] The 2019 amount includes $119 million related to transmission assets transferred from the Transmission Business to NRLP. See Note 8 - Property, Plant and Equipment.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a 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 up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Transmission Business contributions to the DC Plan for the year ended December 31, 2019 were less than $1 million (2018 - less than $1 million).

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 the highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the 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 reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total annual cash Pension Plan employer contributions for 2019 were $61 million (2018 - $75 million). Estimated annual Pension Plan employer contributions for the years 2020, 2021, 2022, 2023 and 2024 are approximately $66 million, $65 million, $64 million, $64 million, and $64 million, respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the 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, 2019, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,973 million (2018 - $7,752 million). The fair value of pension plan assets available for these benefits was $7,848 million (2018 - $7,205 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2019, the Transmission Business charged $16 million (2018 - $16 million) of post-retirement and post-employment benefit costs to operation, maintenance and administration expenses, and capitalized $35 million (2018 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2019 were $21 million (2018 - $21 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was increased by $103 million (2018 - decreased by $73 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

December 31 *(millions of dollars)*	2019	2018
Accrued liabilities	29	26
Post-retirement and post-employment benefit liability	732	602
Net unfunded status	761	628

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2019 and 2018:

Year ended December 31, 2019 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	63	6	69
Interest accretion	3	—	3
Expenditures	(5)	(1)	(6)
Revaluation adjustment	(4)	—	(4)
Environmental liabilities - ending	57	5	62
Less: current portion	(11)	(2)	(13)
	46	3	49

Year ended December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	73	5	78
Interest accretion	3	—	3
Expenditures	(6)	—	(6)
Revaluation adjustment	(7)	1	(6)
Environmental liabilities - ending	63	6	69
Less: current portion	(6)	(1)	(7)
	57	5	62

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, 2019 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	61	5	66
Less: discounting environmental liabilities to present value	(4)	—	(4)
Discounted environmental liabilities	57	5	62

December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	69	6	75
Less: discounting environmental liabilities to present value	(6)	—	(6)
Discounted environmental liabilities	63	6	69

At December 31, 2019, the estimated future environmental expenditures were as follows:

December 31 *(millions of dollars)*	2019
2020	13
2021	17
2022	16
2023	15
2024	5
Thereafter	—
	66

The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% 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 Transmission Business' 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 parts per million.

At December 31, 2019, the Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations was $61 million (2018 - $69 million). These expenditures are expected to be incurred over the period from 2020 to 2024. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2019 to decrease the PCB environmental liability by $4 million (2018 - $7 million).

LAR

At December 31, 2019, the Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program was $5 million (2018 - $6 million). These expenditures are expected to be incurred over the period from 2020 to 2022. As a result of its annual review of environmental liabilities, no revaluation adjustment to the LAR environmental liability was recorded in 2019 in the Transmission Business (2018 - revaluation adjustment was recorded to increase the LAR environmental liability by $1 million).

19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures required to remove and dispose 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 2.0% to 4.0%, 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. Changes in estimates are accounted for prospectively. As a result of its annual review of asset retirement obligations, no revaluation adjustment to the asset retirement obligations was recorded in 2019 in the Transmission Business (2018 - revaluation adjustment was recorded to increase the asset retirement obligations by $1 million).

At December 31, 2019, Hydro One Networks had recorded asset retirement obligations of $5 million (2018 - $5 million) related to the 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.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and seven years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. 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. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Company's operating leases was as follows:

Year ended December 31 *(millions of dollars)*	2019
Lease expense	5
Lease payments made	3

December 31	2019
Weighted-average remaining lease term[1] *(years)*	8
Weighted-average discount rate	2.7%

[1] Includes renewal options that are reasonably certain to be exercised.

At December 31, 2019, future minimum operating lease payments were as follows:

December 31 *(millions of dollars)*	2019
2020	5
2021	5
2022	5
2023	4
2024	4
Thereafter	17
Total undiscounted minimum lease payments[1]	40
Less: discounting minimum lease payments to present value	(4)
Total discounted minimum lease payments	36

[1] Excludes committed amounts of $3 million for leases that have not yet commenced.

At December 31, 2018, future minimum operating lease payments were as follows:

December 31 *(millions of dollars)*	2018
2019	3
2020	5
2021	2
2022	—
2023	—
2024	—
Thereafter	1
Total undiscounted minimum lease payments	11

Hydro One presents its ROU assets and lease obligations on the balance sheet as follows:

December 31 *(millions of dollars)*	2019
Other long-term assets *(Note 11)*	35
Accounts payable and other current liabilities *(Note 12)*	4
Other long-term liabilities *(Note 13)*	33

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2019 and 2018, Hydro One Networks had 209,401,289 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2019, Hydro One Networks declared common share dividends in the amount of $1 million (2018 - $1 million) and made a return of stated capital of $738 million (2018 - $545 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends and return of stated capital was $230 million (2018 - $213 million).

22. 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 Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an inter-company 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 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 Initial Public Offering (IPO). 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 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 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 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 2019, 221,706 common shares were issued under the Share Grant Plans (2018 - 220,022) to eligible employees of Hydro One Networks and allocated to the Transmission Business. Total stock-based compensation recognized by the Transmission Business during 2019 was $4 million (2018 - $6 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, 2019 and 2018 is presented below:

Year ended December 31, 2019	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	1,819,964	$20.50
Vested and issued[1]	(221,706)	—
Forfeited	(45,512)	$20.50
Share grants outstanding - ending	1,552,746	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2018	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,088,926	$20.50
Vested and issued[1]	(220,022)	—
Forfeited	(48,940)	$20.50
Share grants outstanding - ending	1,819,964	$20.50

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

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 Board of Directors.

During 2019 and 2018, Directors' DSU Plan awards granted by Hydro One Limited that related to the Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2019	2018
DSUs outstanding - beginning	19,075	70,908
Granted	10,131	30,413
Settled	(8,127)	(82,246)
DSUs outstanding - ending	21,079	19,075

For the year ended December 31, 2019, the expense related to the Directors' DSU Plan was not significant (2018 - $1 million). At December 31, 2019, the liability related to Directors' DSUs was not significant (2018 - $1 million).

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 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 Board of Directors.

During 2019 and 2018, Management DSU Plan awards granted by Hydro One Limited that related to the Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2019	2018
DSUs outstanding - beginning	41,170	27,341
Granted	7,150	13,829
Other[1]	(30,305)	—
DSUs outstanding - ending	18,015	41,170

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

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 2019, Company contributions made under the ESOP and allocated to the Transmission Business were $1 million (2018 - $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 which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. 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 Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2019 and 2018, LTIP awards granted by Hydro One Limited that related to the Transmission Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2019	2018	2019	2018
Units outstanding – beginning	233,848	179,926	161,029	164,391
Granted	—	125,658	—	104,328
Vested and issued[1]	(13,028)	(60)	(26,662)	(53,695)
Forfeited	(6,158)	(16,832)	(5,349)	(16,873)
Settled	—	(54,844)	—	(37,122)
Other[2]	(154,900)	—	(82,784)	—
Units outstanding – ending	59,762	233,848	46,234	161,029

[1] In 2019 and 2018, Hydro One Limited issued from treasury common shares to eligible Transmission Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

No awards were granted in 2019. The grant date total fair value of the awards granted in 2018 was $5 million. The compensation expense related to the PSU and RSU awards recognized by the Transmission Business during 2019 was not significant (2018 - $4 million).

At December 31, 2019, payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant (2018 - $4 million).

On February 13, 2020, 13,568 PSUs were vested and issued. See Note 27 - Subsequent Events.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. No stock options were granted in 2019 (2018 - 1,450,880 stock options were granted). The stock options granted are exercisable for a period not to exceed seven years from the date of grant.

The fair value-based method is used to measure compensation expense related to stock options and the expense is recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model.

Stock options granted and the weighted-average assumptions used in the valuation model for options granted during 2018 are as follows:

Exercise price[1]	$ 20.70
Grant date fair value per option	$ 1.66
Valuation assumptions:	
Expected dividend yield[2]	3.78%
Expected volatility[3]	15.01%
Risk-free interest rate[4]	2.00%
Expected option term[5]	4.5 years

[1] Hydro One Limited common share price on the date of the grant.
[2] Based on dividend and Hydro One Limited common share price on the date of the grant.
[3] Based on average daily volatility of Hydro One Limited's peer entities for a 4.5-year term.
[4] Based on bond yield for an equivalent Canadian government bond.
[5] Determined using the option term and the vesting period.

During 2018, the activity of stock options granted by Hydro One Limited that related to the Transmission Business was as follows:

	Number of Stock Options	Weighted-average exercise price
Stock options outstanding - January 1, 2018	—	
Granted	280,449	$ 20.70
Forfeited	(57,062)	$ 20.66
Stock options outstanding - December 31, 2018	223,387	$ 20.72
Other[1]	(223,387)	
Stock options outstanding - December 31, 2019	—	

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

23. 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 of Ontario is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2019. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. The following is a summary of the Transmission Business related party transactions during the years ended December 31, 2019 and 2018:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2019	2018
IESO	Transmission services – amounts received[1]	1,562	1,598
OPG	Revenues related to provision of construction and equipment maintenance services	1	2
	Costs related to the purchase of services	1	—
OEB	OEB fees	4	4
Hydro One Limited and its subsidiaries	Interest expense on long-term debt	284	259
	Payments to finance dividends and return of stated capital	230	213
	Revenues for services provided	19	11
	Services received - costs expensed	14	16
	Interest expense on inter-company demand facility	13	16
	Stock-based compensation costs	5	10

[1] Consistent with the Company's revenue recognition policy, the Transmission Business recognized revenues of $1,547 million in 2019 (2018 - $1,584 million).

The amounts due to and from related parties at December 31, 2019 and 2018 are as follows:

December 31 *(millions of dollars)*	2019	2018
Inter-company demand facility	(849)	(897)
Due from related parties	134	127
Due to related parties	(60)	(64)
Accrued interest	(62)	(57)
Long-term inter-company payable	(18)	(17)
Long-term debt, including current portion	(6,524)	(6,074)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2019	2018
Accounts receivable	(47)	7
Due from related parties	(7)	4
Materials and supplies	—	(1)
Other assets	—	19
Accounts payable	(1)	13
Accrued liabilities	6	(37)
Due to related parties	7	1
Accrued interest	5	(1)
Long-term accounts payable and other liabilities	—	(2)
Post-retirement and post-employment benefit liability	6	5
	(31)	8

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2019 and 2018. The reconciling items include change in accruals and capitalized depreciation.

Year ended December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(976)	(57)	(1,033)
Reconciling items	13	—	13
Cash outflow for capital expenditures	(963)	(57)	(1,020)

Year ended December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(934)	(45)	(979)
Reconciling items	16	—	16
Cash outflow for capital expenditures	(918)	(45)	(963)

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 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 2019, the Transmission Business' capital contributions from these reassessments totalled $3 million (2018 - $7 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)*	2019	2018
Net interest paid	279	260
Income taxes paid	9	33

25. 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, were defendants in a class action suit commenced in 2015 in which the representative plaintiff was seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's application for leave to appeal the lower court's refusal to certify the lawsuit as a class action was denied by the Ontario Court of Appeal on March 26, 2019, which means that the lawsuit has effectively ended.

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.

26. 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.

27. SUBSEQUENT EVENTS

Payments to Finance Return of Stated Capital

On February 20, 2020, Hydro One Networks declared a return of stated capital of $146 million. The amount allocated to the Transmission Business to finance this payment was $75 million.

Long-term Debt

On February 28, 2020, Hydro One issued $1,100 million of long-term debt under its MTN Program, $753 million of which was mirrored down to Hydro One Networks, and $542 million was allocated to the Transmission Business.

Stock-based Compensation

Subsequent to December 31, 2019, Hydro One Limited issued from treasury 13,568 and 209,993 common shares to eligible Transmission Business employees in accordance with provisions of the LTIP Plan and Share Grant Plans, respectively.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2020

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2020
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2020 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Preparation

We draw attention to Note 2 in the financial statements which describes the basis of preparation used in these financial statements and the purpose of the financial statements.

As a result, the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 15, 2021

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the years ended December 31, 2020 and 2019

Year ended December 31 *(millions of Canadian dollars)*	**2020**	**2019**
Revenues		
Transmission tariff *(Note 23)*	1,619	1,547
Other	62	47
	1,681	1,594
Costs		
Operation, maintenance and administration *(Note 23)*	414	371
Depreciation, amortization and asset removal costs *(Note 4)*	441	444
	855	815
Income before financing charges and income tax expense	**826**	**779**
Financing charges *(Notes 5, 23)*	264	266
Income before income tax expense	**562**	**513**
Income tax expense (recovery) *(Note 6)*	(54)	11
Net income	**616**	**502**
Other comprehensive income	—	—
Comprehensive income	**616**	**502**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
At December 31, 2020 and 2019

As at December 31 *(millions of Canadian dollars)*	**2020**	**2019**
Assets		
Current assets:		
Accounts receivable	67	83
Due from related parties *(Note 23)*	136	134
Other current assets *(Note 7)*	105	46
	308	263
Property, plant and equipment *(Note 8)*	13,433	12,725
Other long-term assets:		
Regulatory assets *(Note 10)*	1,834	1,054
Intangible assets *(Note 9)*	203	171
Other assets *(Notes 11, 20)*	34	37
	2,071	1,262
Total assets	**15,812**	**14,250**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	133	849
Long-term debt payable within one year *(Notes 14, 15, 23)*	553	180
Accounts payable and other current liabilities *(Note 12)*	415	251
Due to related parties *(Note 23)*	—	60
	1,101	1,340
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	7,073	6,344
Deferred income tax liabilities *(Note 6)*	1,566	817
Regulatory liabilities *(Note 10)*	54	37
Other long-term liabilities *(Note 13)*	848	846
	9,541	8,044
Total liabilities	**10,642**	**9,384**
Contingencies and Commitments *(Notes 25, 26)*		
Subsequent Events *(Note 27)*		
Excess of assets over liabilities *(Notes 16, 21)*	5,170	4,866
Total liabilities and excess of assets over liabilities	**15,812**	**14,250**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Russel Robertson
Chair, Audit Committee

Mark Poweska
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2020 and 2019

Year ended December 31 *(millions of Canadian dollars)*	**2020**	**2019**
Operating activities		
Net income	616	502
Environmental expenditures	(8)	(6)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	402	398
Regulatory assets and liabilities	(52)	(9)
Deferred income tax expense (recovery)	(85)	4
Other	(1)	(9)
Changes in non-cash balances related to operations *(Note 24)*	192	(31)
Net cash from operating activities	**1,064**	**849**
Financing activities		
Long-term debt issued	1,286	885
Long-term debt repaid	(180)	(437)
Payments to finance dividends and return on stated capital	(312)	(230)
Other	(7)	(4)
Net cash from financing activities	**787**	**214**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,084)	(963)
Intangible assets	(56)	(57)
Capital contributions received *(Note 23)*	—	3
Other	5	2
Net cash used in investing activities	**(1,135)**	**(1,015)**
Net change in inter-company demand facility	716	48
Inter-company demand facility, beginning of year	(849)	(897)
Inter-company demand facility, end of year	**(133)**	**(849)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

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 Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's 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).

Rate Setting

On March 7, 2019, the OEB issued its reconsideration decision (DTA Decision) with respect to Hydro One's rate-setting treatment of the benefits of the deferred tax asset resulting from the transition from the payments in lieu of tax regime to tax payments under the federal and provincial tax regimes. On July 16, 2020, the Ontario Divisional Court rendered its decision on the Company's appeal of the OEB's DTA Decision. See Note 10 - Regulatory Assets and Liabilities.

On April 23, 2020, the OEB rendered its decision on Hydro One Networks' 2020-2022 transmission rate application (2020-2022 Transmission Decision). On July 16, 2020, the OEB issued its final rate order for the 2020-2022 transmission rates approving a revenue requirement of $1,630 million, $1,701 million and $1,772 million for 2020, 2021 and 2022, respectively. On July 30, 2020, the OEB issued its decision for Uniform Transmission Rates (UTRs). The 2020 UTRs that were put in place on an interim basis on January 1, 2020 continued for the remainder of 2020 in light of the COVID-19 pandemic. On December 17, 2020, the OEB issued its decision and order setting the final 2021 UTRs effective January 1, 2021, which included the approval of a two-year disposition period for Hydro One Networks' 2020 foregone revenue including interest, beginning on January 1, 2021.

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).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2020 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Transmission Business. 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 Transmission Business. As a result of this basis of preparation, 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. These Financial Statements include deferred taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. 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 15, 2021, 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 27 - 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, and contingencies. Actual results may differ significantly from these estimates.

As the COVID-19 pandemic (COVID-19 or the pandemic) has resulted in incremental operating costs, the Company has also analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no material impact. Additional details regarding the impact of the pandemic on the Financial Statements are available in Note 10 - Regulatory Assets and Liabilities.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Transmission Business' financial results and operations.

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 prospectively from the date the assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Revenue Recognition

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved UTRs, which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are 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 represent 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.

For other accounts receivables, the Transmission Business estimates the current lifetime expected credit losses by applying internally developed loss rates to all outstanding other accounts receivables by aging category. Loss rates applied to the other accounts receivables balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Other accounts receivables 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.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year’s taxable income. 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 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 tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including 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 associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

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.

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 0.15%. 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, and information technology (IT). 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, administration and service, and other communication assets as well as 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.

<u>Transmission</u>

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.

<u>Administration and Service</u>

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

<u>Other</u>

Other assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, and 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 Transmission Business' 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, 2020 for the 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	Average
Property, plant and equipment:			
Transmission	54 years	1% - 2%	2%
Communication	17 years	1% - 6%	4%
Administration and service	22 years	1% - 20%	4%
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.

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, 2020 and 2019, no asset impairment had been recorded for assets within the Transmission Business.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Transmission Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred 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 / Loss

Comprehensive income/loss is comprised of net income/loss and other comprehensive income (OCI) or other comprehensive loss (OCL). OCI/OCL and net income are presented in a single continuous statement of operations and comprehensive income/loss.

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 its net realizable value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Transmission Business 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.

The Transmission Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Transmission Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Transmission Business' risk management policy disclosed in Note 15 - 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, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. 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 that required bifurcation at December 31, 2020 or 2019.

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 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 plan (Pension Plan) and its 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 (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO 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 PBO of the plan, an asset is recognized equal to the net overfunded PBO. 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 (DC 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 (OM&A) 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.

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 reflective of earnings allocations of relevant employees to the Company's Transmission Business.

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 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 benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's 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 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 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the 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 (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. 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. This uncertainty is incorporated in the fair value measurement of the obligation.

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. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. 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.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a re-measurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Transmission Business
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Transmission Business
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-01	January 2020	The amendments clarify the interaction of the accounting for equity securities under Topic 321, investments under the equity method of accounting in Topic 323 and the accounting for certain forward contracts and purchased options accounted for under Topic 815.	January 1, 2021	No impact upon adoption
ASU 2020-06	August 2020	The update addresses the complexity associated with applying GAAP for certain financial instruments with characteristics of liabilities and equity. The amendments reduce the number of accounting models for convertible debt instruments and convertible preferred stock.	January 1, 2022	Under assessment
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2020	2019
Depreciation of property, plant and equipment	371	363
Amortization of intangible assets	23	29
Amortization of regulatory assets	8	6
Depreciation and amortization	402	398
Asset removal costs	39	46
	441	444

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2020	2019
Interest on long-term debt *(Note 23)*	295	284
Interest on inter-company demand facility *(Note 23)*	4	13
Other	6	10
Less: Interest capitalized on construction and development in progress	(41)	(41)
	264	266

6. INCOME TAXES

As a rate regulated utility business, the Transmission Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Transmission Business' tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Transmission Business' income tax expense or recovery 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)*	**2020**	**2019**
Income before income tax expense	562	513
Income tax expense at statutory rate of 26.5% (2019 - 26.5%)	149	136
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization[1]	(64)	(64)
Impact of tax deductions from deferred tax asset sharing[2]	(24)	(26)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(12)
Interest capitalized for accounting but deducted for tax purposes	(11)	(11)
Pension and post-retirement benefit contributions in excess of expense	(2)	(8)
Environmental expenditures	(2)	(1)
Other	(1)	(4)
Net temporary differences attributable to regulated business	(116)	(126)
Net permanent differences	—	1
Recognition of deferred income tax regulatory asset *(Note 10)*	(87)	—
Total income tax expense (recovery)	(54)	11
Effective income tax rate	(9.6)%	2.1 %

[1] Includes accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.
[2] Prior to the ODC Decision, the impact represents tax deductions from deferred asset tax sharing given to ratepayers as previously mandated by the OEB. Subsequent to the ODC Decision, the impact represents the recovery of deferred tax asset sharing currently allocated to rate-payers. See Note 10 - Regulatory Assets and Liabilities.

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	**2020**	**2019**
Current income tax expense	31	7
Deferred income tax expense (recovery)	(85)	4
Total income tax expense (recovery)	(54)	11

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Transmission Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and liabilities consisted of the following:

As at December 31 *(millions of dollars)*	**2020**	**2019**
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,769)	(1,055)
Regulatory assets and liabilities	(90)	(45)
Post-retirement and post-employment benefits expense in excess of cash payments	289	273
Environmental expenditures	19	22
Other	(12)	(9)
	(1,563)	(814)
Less: valuation allowance	(3)	(3)
Net deferred income tax liabilities[1]	(1,566)	(817)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term liabilities.

7. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	2020	2019
Regulatory assets *(Note 10)*	68	18
Prepaid expenses and other assets	21	16
Materials and supplies	13	12
Derivative assets *(Note 15)*	3	—
	105	46

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2020 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	17,381	5,917	873	12,337
Administration and service	623	333	58	348
Other	1,565	856	39	748
	19,569	7,106	970	13,433

[1] Includes future use assets totalling $103 million.

As at December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	16,625	5,658	709	11,676
Administration and service	582	322	23	283
Other	1,533	805	38	766
	18,740	6,785	770	12,725

[1] Includes future use assets totalling $97 million.

On September 18, 2019, transmission assets related to a new 230 kV transmission line (Niagara Line) in the Niagara region totalling $119 million were transferred from Hydro One Networks to Niagara Reinforcement Limited Partnership (NRLP), a subsidiary of Hydro One Networks. See Note 16 - Capital Management.

Financing charges capitalized on property, plant and equipment under construction were $40 million in 2020 (2019 - $39 million).

9. INTANGIBLE ASSETS

As at December 31, 2020 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	401	237	29	193
Other	16	6	—	10
	417	243	29	203

As at December 31, 2019 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	359	216	21	164
Other	12	5	—	7
	371	221	21	171

Financing charges capitalized to intangible assets under development were $1 million in 2020 (2019 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2021 - $24 million; 2022 - $22 million; 2023 - $21 million; 2024 - $19 million; and 2025 - $19 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:

As at December 31 *(millions of dollars)*	2020	2019
Regulatory assets:		
Deferred income tax regulatory asset	1,551	885
Deferred tax asset sharing	134	—
Foregone revenue deferral	55	—
Environmental	51	62
Post-retirement and post-employment benefits non-service cost	45	51
Post-retirement and post-employment benefits	27	47
Stock-based compensation	19	23
Conservation and Demand Management (CDM) variance	16	—
Other	4	4
Total regulatory assets	1,902	1,072
Less: current portion	(68)	(18)
	1,834	1,054
Regulatory liabilities:		
Tax rule changes variance	21	20
Asset removal costs cumulative variance	19	—
External revenue variance	7	6
Pension cost differential	7	9
Deferred income tax regulatory liability	—	32
Other	2	2
Total regulatory liabilities	56	69
Less: current portion	(2)	(32)
	54	37

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 2020 income tax expense would have been higher by approximately $116 million (2019 - higher by $129 million), of which $92 million is included in Deferred Income Tax Regulatory Asset and Liability with the remaining $24 million included in Deferred Tax Asset Sharing.

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited 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 have resulted in an impairment of a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its DTA Decision and concluded that their Original Decision was reasonable and should be upheld. As a result, as at December 31, 2018, the Company recorded impairment charges relating to Hydro One Networks' distribution and transmission deferred income tax regulatory asset. Notwithstanding the recognition of the effects of the DTA Decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's DTA Decision. The appeal was heard on November 21, 2019.

On July 16, 2020, the Ontario Divisional Court rendered its decision (ODC Decision) on the Company's appeal of the OEB's DTA Decision.

In connection with the ODC Decision, the Transmission Business recorded a reversal of the previously recognized impairment charge of the deferred income tax regulatory asset in its financial statements for the year ended December 31, 2020. The reversal of the previously recognized impaired charge included the regulatory asset relating to the cumulative deferred tax asset amounts shared with ratepayers (deferred tax asset sharing) up to and including June 30, 2020 by the Transmission Business of $118 million. The Transmission Business recognized deferred income tax regulatory assets of $673 million and associated deferred income tax liability of $586 million. The Transmission Business also recorded an increase in net income of $87 million as deferred income tax recovery during the year ended December 31, 2020.

Deferred Tax Asset Sharing

On October 2, 2020, the OEB issued a procedural order to implement the direction of the Ontario Divisional Court and required Hydro One to submit its proposal for the recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2022 period. As at December 31, 2020, the Transmission Business recorded a regulatory asset of $134 million for the cumulative deferred tax asset amounts shared with ratepayers since 2017 to date. As a result of the OEB’s procedural order, the $134 million regulatory asset relating to the cumulative deferred tax asset amounts allocated to ratepayers since 2017 has been separately presented from the deferred income tax regulatory asset. Additional amounts shared with ratepayers up to December 31, 2021 will continue to increase this regulatory asset. On April 8, 2021, the OEB rendered its decision and order regarding the recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2022 period (Implementation Decision). In its decision, the OEB approved recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2021 period including the $134 million at December 31, 2020. See Note 27 – Subsequent Events for additional information.

Foregone Revenue Deferral

As at December 31, 2020, the foregone revenue deferral account is primarily made up of the difference between revenue earned by the Transmission Business under the approved UTRs based on OEB-approved 2020 rates revenue requirement and load forecast and the revenues earned under interim 2020 UTRs. The Transmission Business' foregone revenue, including accrued interest, is being collected from ratepayers over a two-year period ending December 31, 2022.

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. In 2020, the environmental regulatory asset decreased by $5 million (2019 - $4 million) to reflect related changes in the Transmission Business' PCB and LAR environmental liabilities. 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, 2020 OM&A expenses would have been lower by $5 million (2019 - $4 million). In addition, 2020 amortization expense would have been lower by $8 million (2019 - $6 million), and 2020 financing charges would have been higher by $2 million (2019 - $3 million).

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. As part of Hydro One Networks' 2020-2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's other post-employment benefits costs shall be recognized as OM&A for the Transmission Business. The OEB approved the disposition of the Transmission Business' account balance as at December 31, 2018, including accrued interest, which is being collected from ratepayers over a three-year period ending December 31, 2022.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. 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 the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2020 OCI would have been higher by $20 million (2019 - lower by $103 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, there would be no material impact to OM&A expenses in 2020 and 2019. 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.

CDM Variance

The CDM variance account tracks the impact of actual CDM and demand response programs on the actual load forecast compared to the estimated load forecast included in revenue requirement. As per the OEB's decision on Hydro One Networks' 2017 and 2018 transmission rates, and 2019 transmission rates, this account was maintained to record any variances for 2017, 2018, and 2019. A CDM variance amount for 2017 was calculated and proposed for disposition in Hydro One Networks' 2020-2022 transmission rate application. In April 2020, the amount as at December 31, 2018, including accrued interest, was approved for disposition by the OEB and was recognized as a regulatory asset. The amount was approved to be recovered from ratepayers over a three-year period ending December 31, 2022.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting the Transmission Business to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including the Transmission Business to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for the Transmission Business to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs incurred from 2020 to 2022. This account is asymmetrical to the benefit of ratepayers on a cumulative basis over the 2020-2022 rate period.

External Revenue Variance

The external revenue variance account balance reflects the difference between actual export service revenue and external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts. In April 2020, the OEB approved the disposition of the external revenue variance account as at December 31, 2018, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2022.

Pension Cost Differential

Variances between the pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Transmission Business are recognized as a regulatory asset or regulatory liability, as the case may be. In April 2020, the OEB approved the disposition of the Transmission Business' balance as at December 31, 2018, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2022. In the absence of rate-regulated accounting, there would have been no impact to revenue (2019 - $5 million).

COVID-19 Emergency Deferral

The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from Postponing Rate Implementation, and (v) Bad Debt.

The Transmission Business continues to track certain incremental costs that have arisen due to the COVID-19 pandemic. As at December 31, 2020, the Transmission Business has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory assets.

11. OTHER LONG-TERM ASSETS

As at December 31 *(millions of dollars)*	2020	2019
Right-of-Use assets *(Notes 3, 20)*	34	35
Derivative assets *(Note 15)*	—	1
Other long-term assets	—	1
	34	37

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	2020	2019
Accrued liabilities	181	31
Accounts payable	142	109
Accrued interest *(Note 23)*	69	62
Regulatory liabilities *(Note 10)*	2	32
Environmental liabilities *(Note 18)*	16	13
Lease obligations *(Note 20)*	5	4
	415	251

13. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	2020	2019
Post-retirement and post-employment benefit liability *(Note 17)*	751	732
Environmental liabilities *(Note 18)*	35	49
Lease obligations *(Note 20)*	31	33
Long-term inter-company payable *(Note 23)*	14	18
Long-term accounts payable and other liabilities	10	9
Asset retirement obligations *(Note 19)*	7	5
	848	846

14. 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, 2020 and 2019:

As at December 31 *(millions of dollars)*	2020	2019
Long-term debt	7,650	6,544
Add: Net unamortized debt premiums	4	5
Add: Unrealized mark-to-market loss[1]	3	1
Less: Deferred debt issuance costs	(31)	(26)
Less: Long-term debt payable within one year	(553)	(180)
Long-term debt	7,073	6,344

[1] The unrealized mark-to-market net loss of $3 million (2019 - $1 million) relates to $300 million notes due 2021. The unrealized mark-to-market net loss is offset by a $3 million unrealized mark-to-market gain (2019 - $1 million) on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2020, Hydro One issued $2,300 million long-term debt under its MTN Program (2019 - $1,500 million), of which $1,953 million was mirrored down to Hydro One Networks, and $1,286 million was allocated to the Transmission Business.

In 2020, Hydro One repaid $650 million (2019 - $728 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $330 million (2019 - $728 million) to Hydro One, of which $180 million (2019 - $437 million) was allocated to the Transmission Business.

Principal and Interest Payments

At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments	Interest Payments	Weighted Average Interest Rate
	(millions of dollars)	*(millions of dollars)*	*(%)*
Year 1	550	294	2.5
Year 2	319	284	3.2
Year 3	372	277	1.0
Year 4	413	270	2.8
Year 5	416	258	2.7
	2,070	1,383	2.4
Years 6-10	1,045	1,202	4.1
Thereafter	4,535	2,502	4.6
	7,650	5,087	4.0

15. 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 Transmission Business 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, 2020 and 2019, 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, 2020 and 2019 are as follows:

As at December 31 *(millions of dollars)*	2020 Carrying Value	2020 Fair Value	2019 Carrying Value	2019 Fair Value
$300 million notes due 2021	303	303	301	301
Other notes and debentures	7,323	9,087	6,223	6,984
Long-term debt, including current portion	7,626	9,390	6,524	7,285

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, 2020, the Transmission Business' share of the Company's derivative instruments included $300 million (2019 - $300 million) interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Transmission Business' fair value hedge exposure was approximately 4% (2019 - 5%) of its total long-term debt. At December 31, 2020, the Transmission Business' interest-rate swap designated as a fair value hedge:

- a $300 million fixed-to-floating interest-rate swap agreement to convert the $300 million notes maturing June 25, 2021 into three-month variable rate debt.

At December 31, 2020 and 2019, 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, 2020 and 2019 is as follows:

As at December 31, 2020 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments - fair value hedges (*Note 7*)	3	3	—	3	—
	3	3	—	3	—
Liabilities:					
Long-term debt, including current portion	7,626	9,390	—	9,390	—
	7,626	9,390	—	9,390	—

As at December 31, 2019 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments - fair value hedges (*Note 11*)	1	1	—	1	—
	1	1	—	1	—
Liabilities:					
Long-term debt, including current portion	6,524	7,285	—	7,285	—
	6,524	7,285	—	7,285	—

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, 2020 or 2019.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company’s business.

<u>Market Risk</u>

Market risk refers primarily to the risk of loss which results from changes in values, 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.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. 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. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments to lock in interest-rate levels on forecasted 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, 2020 and 2019.

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 net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2020 and 2019 were not material.

<u>Credit Risk</u>

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2020 and 2019, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business' revenue is earned from IESO, which has a remote risk of default.

The allowance for doubtful accounts reflects the Transmission Business' current lifetime expected credit losses for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2020, approximately 0% (2019 - 5%) 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 (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both 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 maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2020 and 2019, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2020, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, was with four financial institutions with investment grade credit ratings as 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 operating 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. The Company's currently available liquidity is also expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Company's cash requirements.

16. 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, 2020 and 2019, the Transmission Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	2020	2019
Long-term debt payable within one year	553	180
Inter-company demand facility	133	849
	686	1,029
Long-term debt	7,073	6,344
Excess of assets over liabilities	5,170	4,866
Total capital	12,929	12,239

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31 *(millions of dollars)*	2020	2019
Excess of assets over liabilities - beginning	4,866	4,729
Net income	616	502
Payments to Hydro One to finance dividends and return of stated capital	(312)	(230)
Other[1,2]	—	(135)
Excess of assets over liabilities - ending	5,170	4,866

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Transmission Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Transmission Business, resulting in an impact to excess of assets over liabilities.
[2] The 2019 amount includes $119 million related to transmission assets transferred from the Transmission Business to NRLP. See Note 8 - Property, Plant and Equipment.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a 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 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 up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. The Transmission Business contributions to the DC Plan for the year ended December 31, 2020 were $1 million (2019 - less than $1 million).

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 United Professionals (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 reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total annual cash Pension Plan employer contributions for 2020 allocated to the Transmission Business were $27 million (2019 - $26 million). The estimated annual Pension Plan employer contributions allocated to the Transmission Business for the years 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $24 million, $41 million, $45 million, $46 million, $46 million, $47 million and $49 million, respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the 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, 2020, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,763 million (2019 - $8,973 million). The fair value of pension plan assets available for these benefits was $8,103 million (2019 - $7,848 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2020, the Transmission Business charged $14 million (2019 - $16 million) of post-retirement and post-employment benefit costs to operation, maintenance and administration expenses, and capitalized $46 million (2019 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2020 were $21 million (2019 - $21 million). In addition, the associated post-retirement and post-employment benefits regulatory asset decreased by $20 million (2019 - increased by $103 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	**2020**	**2019**
Accrued liabilities	29	29
Post-retirement and post-employment benefit liability	751	732
Net unfunded status	780	761

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	57	5	62
Interest accretion	2	—	2
Expenditures	(7)	(1)	(8)
Revaluation adjustment	(4)	(1)	(5)
Environmental liabilities - ending	48	3	51
Less: current portion	(15)	(1)	(16)
	33	2	35

Year ended December 31, 2019 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	63	6	69
Interest accretion	3	—	3
Expenditures	(5)	(1)	(6)
Revaluation adjustment	(4)	—	(4)
Environmental liabilities - ending	57	5	62
Less: current portion	(11)	(2)	(13)
	46	3	49

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:

As at December 31, 2020 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	51	3	54
Less: discounting environmental liabilities to present value	(3)	—	(3)
Discounted environmental liabilities	48	3	51

As at December 31, 2019 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	61	5	66
Less: discounting environmental liabilities to present value	(4)	—	(4)
Discounted environmental liabilities	57	5	62

At December 31, 2020, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2021	16
2022	17
2023	8
2024	7
2025	6
Thereafter	—
	54

The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% 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 Transmission Business' 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.

At December 31, 2020, the Transmission Business' best estimate of the total estimated future expenditures to comply with current PCB regulations was $51 million (2019 - $61 million). These expenditures are expected to be incurred over the period from 2021 to 2025. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2020 to decrease the PCB environmental liability by $4 million (2019 - $4 million).

LAR

At December 31, 2020, the Transmission Business' best estimate of the total estimated future expenditures to complete its LAR program was $3 million (2019 - $5 million). These expenditures are expected to be incurred over the period from 2021 to 2023. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2020 to decrease the LAR environmental liability by $1 million (2019 - no revaluation adjustment was recorded the LAR environmental liability).

19. 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 2.0% to 4.0%, 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. As a result of its annual review of asset retirement obligations, the Transmission Business recorded a revaluation adjustment in 2020 to increase the assets retirement liability by $2 million (2019 - $nil).

At December 31, 2020, Hydro One Networks had recorded asset retirement obligations of $7 million (2019 - $5 million) related to the 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.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and seven years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. 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. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Transmission Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2020**	**2019**
Lease expense	6	5
Lease payments made	6	3

As at December 31	**2020**	**2019**
Weighted-average remaining lease term[1] *(years)*	7	8
Weighted-average discount rate	2.6 %	2.7 %

[1] Includes renewal options that are reasonably certain to be exercised.

At December 31, 2020, future minimum operating lease payments were as follows:

(millions of dollars)	
2021	6
2022	5
2023	5
2024	5
2025	5
Thereafter	14
Total undiscounted minimum lease payments	40
Less: discounting minimum lease payments to present value	(4)
Total discounted minimum lease payments	36

At December 31, 2019, future minimum operating lease payments were as follows:

(millions of dollars)	
2020	5
2021	5
2022	5
2023	4
2024	4
Thereafter	17
Total undiscounted minimum lease payments[1]	40
Less: discounting minimum lease payments to present value	(4)
Total discounted minimum lease payments	36

[1] Excludes committed amounts of $3 million for leases that have not yet commenced.

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2020**	**2019**
Other long-term assets *(Note 11)*	34	35
Accounts payable and other current liabilities *(Note 12)*	5	4
Other long-term liabilities *(Note 13)*	31	33

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2020 and 2019, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2020, Hydro One Networks declared common share dividends in the amount of $1 million (2019 - $1 million) and made a return of stated capital of $607 million (2019 - $738 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends and return of stated capital was $312 million (2019 - $230 million).

22. 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 Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (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 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 Initial Public Offering (IPO). 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 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 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 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 2020, 210,898 common shares of Hydro One Limited were issued under the Share Grant Plans (2019 - 221,706) to eligible employees of Hydro One Networks and allocated to the Transmission Business. Total stock-based compensation recognized by the Transmission Business during 2020 was $3 million (2019 - $4 million) and was recorded as a regulatory asset.

A summary of the Transmission Business' share grant activity under the Share Grant Plans during the years ended December 31, 2020 and 2019 is presented below:

Year ended December 31, 2020	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	1,552,746	$20.50
Vested and issued[1]	(201,711)	—
Transfers to Hydro One Remote Communities[2]	(1,347)	$20.50
Transfers from Distribution Business[3]	126,429	$20.50
Forfeited	(35,875)	$20.50
Share grants outstanding - ending	1,440,242	$20.50

[1] In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] These transfers relate to share grants allocated to the Transmission Business for PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

[3] These transfers relate to share grants allocations between Hydro One Networks' Transmission and Distribution Businesses.

Year ended December 31, 2019	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	1,819,964	$20.50
Vested and issued[1]	(221,706)	—
Forfeited	(45,512)	$20.50
Share grants outstanding - ending	1,552,746	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

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 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 Board of Directors.

During 2020 and 2019, Directors' DSU Plan awards granted by Hydro One Limited that related to the Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2020	2019
DSUs outstanding - beginning	21,079	19,075
Granted	7,635	10,131
Settled	(5,923)	(8,127)
DSUs outstanding - ending	22,791	21,079

For the years ended December 31, 2020 and 2019, the expense related to the Directors' DSU Plan was less than $1 million. At December 31, 2020, the liability related to Directors' DSUs was $1 million (2019 - less than $1 million).

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 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 Board of Directors.

During 2020 and 2019, Management DSU Plan awards granted by Hydro One Limited that related to the Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2020	2019
DSUs outstanding - beginning	18,015	41,170
Granted	3,061	7,150
Paid	(7,113)	—
Other [1]	—	(30,305)
DSUs outstanding - ending	13,963	18,015

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended December 31, 2020, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

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 2020, Company contributions made under the ESOP and allocated to the Transmission Business were $1 million (2019 - $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 which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. 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 Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, 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.

PSUs and RSUs

During 2020 and 2019, LTIP awards granted by Hydro One Limited that related to the Transmission Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2020**	**2019**	**2020**	**2019**
Units outstanding – beginning	59,762	233,848	46,234	161,029
Vested and issued[1]	(15,741)	(13,028)	(2,091)	(26,662)
Forfeited	(3,160)	(6,158)	(2,973)	(5,349)
Other[2]	—	(154,900)	—	(82,784)
Units outstanding – ending	40,861	59,762	41,170	46,234

[1] In 2020 and 2019, Hydro One Limited issued from treasury common shares to eligible Transmission Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended December 31, 2020, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

No awards were granted in 2020 or 2019. The compensation expense related to the PSU and RSU awards recognized by the Transmission Business during 2020 and 2019 was not significant. At December 31, 2020 and 2019, the payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant.

23. 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 of Ontario is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2020. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. B2M Limited Partnership (B2M LP) is a subsidiary of Hydro One Networks, Hydro One Sault Ste. Marie LP (HOSSM) is a subsidiary of Hydro One, and Hydro One Telecom Inc. (Hydro One Telecom) is a subsidiary of Hydro One Limited. The following is a summary of the Transmission Business' related party transactions during the years ended December 31, 2020 and 2019:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2020	2019
IESO	Revenues for transmission services[1]	1,633	1,562
OPG	Capital contribution received from OPG	3	—
	Costs related to the purchase of services	2	1
	Revenues related to provision of construction and equipment maintenance services	1	1
OEB	OEB fees	4	4
Hydro One	Payments to finance dividends and return of stated capital	312	230
	Interest expense on long-term debt	295	284
	Interest expense on inter-company demand facility	4	13
	Stock-based compensation costs	4	5
	Services received - costs expensed	1	1
B2M LP	Revenues for services provided	5	1
HOSSM	Revenues for services provided	16	13
Hydro One Networks' Distribution Business	Revenues for services provided	2	3
	Capital contribution made	3	6
Hydro One Telecom	Services received - costs expensed	16	15
	Revenues for services provided	2	2
Hydro One Limited and its other subsidiaries	Revenues for services provided	1	—
	Services received - costs recovered	2	2

[1] Consistent with the Company's revenue recognition policy, the Transmission Business recognized revenues of $1,619 million in 2020 (2019 - $1,547 million).

The amounts due to and from related parties at December 31, 2020 and 2019 are as follows:

As at December 31 *(millions of dollars)*	2020	2019
Inter-company demand facility	(133)	(849)
Due from related parties	136	134
Due to related parties	—	(60)
Accrued interest	(69)	(62)
Long-term inter-company payable	(14)	(18)
Long-term debt, including current portion	(7,626)	(6,524)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2020	2019
Accounts receivable	18	(47)
Due from related parties	(2)	(7)
Materials and supplies	(1)	—
Other assets	(3)	—
Accounts payable	36	(1)
Accrued liabilities	151	6
Due to related parties	(60)	7
Accrued interest	7	5
Long-term accounts payable and other liabilities	1	—
Post-retirement and post-employment benefit liability	45	6
	192	(31)

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2020 and 2019. The reconciling items include net change in accruals and capitalized depreciation.

Year ended December 31, 2020 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,097)	(54)	(1,151)
Reconciling items	13	(2)	11
Cash outflow for capital expenditures	(1,084)	(56)	(1,140)

Year ended December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(976)	(57)	(1,033)
Reconciling items	13	—	13
Cash outflow for capital expenditures	(963)	(57)	(1,020)

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 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 2020, there were no capital contributions from these assessments (2019 - $3 million). In 2019, this represented 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)*	2020	2019
Net interest paid	288	279
Income taxes paid	13	9

25. 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 Transmission Business' financial position, results of operations or cash flows.

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.

26. 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.

27. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 23, 2021, Hydro One Networks declared a dividend of $149 million. The amount allocated to the Transmission Business to finance this payment was $78 million.

Deferred Tax Asset Sharing

On April 8, 2021, the OEB rendered the Implementation Decision. In its decision, the OEB approved recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2021 period plus carrying charges over a two-year period commencing on July 1, 2021. In addition, Hydro One shall adjust the transmission revenue requirement beginning January 1, 2022 to eliminate any further amounts of future tax savings flowing to customers. The impact of the Implementation Decision will be reflected prospectively in the Transmission Business' financial statements.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2019

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2019
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "carve-out financial statements").

In our opinion, the accompanying carve-out financial statements as at and for the year ended December 31, 2019 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these carve-out financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Preparation

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.

The purpose of the carve-out financial statements is to meet Hydro One Networks Inc.'s obligation to the Ontario Energy Board. As a result, these carve-out financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Carve-Out Financial Statements

Management is responsible for the preparation of the carve-out financial statements in accordance with the financial reporting framework described in Note 2 in the carve-out financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements

Our objectives are to obtain reasonable assurance about whether the carve-out financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the carve-out financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the carve-out financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

We have served as the Company's auditor since 2008

Toronto, Canada
April 22, 2020

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2019 and 2018

Year ended December 31 *(millions of Canadian dollars)*	2019	2018
Revenues		
Energy sales	4,448	4,078
Rural rate protection *(Note 23)*	240	239
Other	44	52
	4,732	4,369
Costs		
Purchased power *(Note 23)*	3,111	2,900
Operation, maintenance and administration *(Note 23)*	572	568
Depreciation, amortization and asset removal costs *(Note 4)*	407	396
	4,090	3,864
Income before financing charges and income tax expense	**642**	**505**
Financing charges *(Notes 5, 23)*	189	174
Income before income tax expense	**453**	**331**
Income tax expense *(Note 6)*	35	50
Net income	**418**	**281**
Other comprehensive income	—	—
Comprehensive income	**418**	**281**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2019 and 2018

December 31 *(millions of Canadian dollars)*	2019	2018
Assets		
Current assets:		
Accounts receivable *(Note 7)*	610	578
Due from related parties *(Note 23)*	278	125
Other current assets *(Note 8)*	103	34
	991	737
Property, plant and equipment *(Note 9)*	7,757	7,511
Other long-term assets:		
Regulatory assets *(Note 11)*	355	204
Intangible assets *(Note 10)*	320	309
Goodwill	168	168
Right-of-Use assets *(Note 20)*	36	—
	879	681
Total assets	**9,627**	**8,929**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	303	392
Long-term debt payable within one year *(Notes 14, 15, 23)*	150	291
Accounts payable and other current liabilities *(Note 12)*	834	720
Due to related parties *(Note 23)*	302	84
	1,589	1,487
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	4,085	3,620
Deferred income tax liabilities *(Note 6)*	158	33
Regulatory liabilities *(Note 11)*	125	217
Other long-term liabilities *(Note 13)*	1,035	856
	5,403	4,726
Total liabilities	**6,992**	**6,213**
Contingencies and Commitments (Notes 25, 26)		
Subsequent Events (Note 27)		
Excess of assets over liabilities *(Notes 16, 21)*	2,635	2,716
Total liabilities and excess of assets over liabilities	**9,627**	**8,929**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Russel Robertson
Chair, Audit Committee

Mark Poweska
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2019 and 2018

Year ended December 31 *(millions of Canadian dollars)*	2019	2018
Operating activities		
Net income	418	281
Environmental expenditures	(15)	(15)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	352	345
Regulatory assets and liabilities	(33)	53
Deferred income tax expense (recovery)	8	(15)
Other	7	6
Changes in non-cash balances related to operations *(Note 24)*	126	(27)
Net cash from operating activities	**863**	**628**
Financing activities		
Long-term debt issued	615	412
Long-term debt repaid	(291)	(337)
Payments to finance dividends and return on stated capital	(496)	(333)
Other	(2)	(4)
Net cash used in financing activities	**(174)**	**(262)**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(540)	(483)
Intangible assets	(59)	(75)
Other	(1)	13
Net cash used in investing activities	**(600)**	**(545)**
Net change in inter-company demand facility	89	(179)
Inter-company demand facility, beginning of year	(392)	(213)
Inter-company demand facility, end of year	**(303)**	**(392)**

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 Company's regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. On March 7, 2019, the OEB rendered its decision on the distribution rates application. In accordance with the OEB decision, the Company filed its draft rate order reflecting updated revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022. On June 11, 2019, the OEB approved the rate order confirming these updated revenue requirements. See Note 11 - Regulatory Assets and Liabilities for additional information.

On March 26, 2019, the Company filed a motion to review and vary the OEB's decision with respect to recovery of pension costs. On December 19, 2019, the OEB affirmed its earlier decision with respect to recovery of the pension costs. See Note 11 - Regulatory Assets and Liabilities for additional information.

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), with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2019 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Distribution Business. 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 Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution 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 Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution 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 Distribution Business was a separate taxpaying entity. These Financial Statements include deferred taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. 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 22, 2020, 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 27 - 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, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

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 Distribution 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Distribution 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 Distribution 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 prospectively from the date the assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Revenue Recognition

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, the volume of 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 are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

The Distribution Business early-adopted Accounting Standard Update (ASU) 2016-13 *Financial Instruments - Credit Losses* (along with related ASUs as disclosed in Note 3 - New Accounting Pronouncements) with a transition date of January 1, 2019 using the modified retrospective method. Upon adoption, there was no material impact to the Financial Statements, and no adjustments were made to prior period financial statements.

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' current lifetime expected credit losses (CECL) for all accounts receivable balances. The Distribution Business estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the 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.

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 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 assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including 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 Distribution Business recognizes deferred income taxes associated with its regulated operations and records offsetting regulatory assets and liabilities for the deferred income taxes that are expected to be recovered or refunded in future regulated rates charged to customers.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

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 Distribution 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, and information technology. 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 distribution, communication, administration and service assets. 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.

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.

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 Distribution 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, 2015 for Distribution Business. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate	
	Service Life	Range	Average
Property, plant and equipment:			
Distribution	47 years	1% - 7%	2%
Communication	8 years	1% - 15%	11%
Administration and service	20 years	1% - 20%	5%
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, 2019, the Company has concluded that goodwill was not impaired at December 31, 2019.

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 Distribution 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, 2019 and 2018, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Distribution Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred 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 (i) held-to-maturity, (ii)loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) 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 Distribution Business 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. The Distribution Business estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

The Distribution Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Distribution Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Distribution Business' risk management policy disclosed in Note 15 - 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, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. 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 (i) 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, (ii) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period, and (iii) 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 that required bifurcation at December 31, 2019 or 2018.

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 (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO 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 PBO of the plan, an asset is recognized equal to the net overfunded PBO. 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 (DC 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 (OM&A) 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.

<u>Post-retirement and Post-employment Benefits</u>

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.

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 or liability as the case may be, 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 or liability as the case may be, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited 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 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 awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the 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 Distribution 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 Distribution 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 Distribution Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. 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. This uncertainty is incorporated in the fair value measurement of the obligation.

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. The present value is determined with a discount rate that equates to the Company’s credit-adjusted risk-free rate. 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 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 Distribution 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 Distribution 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.

Leases

Effective January 1, 2019, the Company adopted Accounting Standards Codification (ASC) 842 - *Leases* using the modified retrospective transition approach using the effective date of January 1, 2019, as its date of initial application. In the Company's transition to ASC 842, the Company elected the package of practical expedients and the land easement practical expedient. As a result, a Right-of-Use (ROU) asset and a corresponding lease obligation of approximately $12 million was recognized on the balance sheet at January 1, 2019, and no adjustments were made to prior period financial statement amounts. There was no material impact to the statement of operations and comprehensive income. On adoption, the Company did not identify any finance leases.

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding ROU asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets are calculated as the difference between the lease expense and the accretion of interest, which is calculated on the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a re-measurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present ASCs and ASUs issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASC 842	February 2016 - January 2019	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	Hydro One adopted ASC 842 on January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption. The Company has included the disclosure requirements of ASC 842 in Note 20 to the Financial Statements.
ASU 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 presentation of hedge results.	January 1, 2019	No impact upon adoption
ASU 2018-07	June 2018	Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees.	January 1, 2019	No impact upon adoption
ASU 2018-15	August 2018	The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment.	January 1, 2019	Hydro One early-adopted this ASU with a transition date of January 1, 2019. The ASU was applied prospectively and there was no material impact upon adoption.
ASU 2016-13 2018-19 2019-04 2019-05 2019-11	June 2016 - November 2019	The amendments provide users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.	January 1, 2019	Hydro One early-adopted these ASUs with a transition date of January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
ASU 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	No impact upon adoption
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	Under assessment
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are not applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2019	2018
Depreciation of property, plant and equipment	280	278
Amortization of intangible assets	57	52
Amortization of regulatory assets	15	15
Depreciation and amortization	352	345
Asset removal costs	55	51
	407	396

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2019	2018
Interest on long-term debt *(Note 23)*	181	168
Interest on inter-company demand facility *(Note 23)*	6	4
Other	9	10
Less: Interest capitalized on construction and development in progress	(7)	(8)
	189	174

6. INCOME TAXES

As a rate regulated utility business, the Distribution Business' effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. 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)*	2019	2018
Income before income tax expense	453	331
Income tax expense at statutory rate of 26.5% (2018 - 26.5%)	120	88
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization[1]	(35)	(20)
Impact of tax deductions from deferred tax asset sharing[2]	(34)	—
Overheads capitalized for accounting but deducted for tax purposes	(8)	(7)
Pension and post-retirement benefit contributions in excess of expense	(4)	(5)
Environmental expenditures	(4)	(4)
Interest capitalized for accounting but deducted for tax purposes	(2)	(2)
Other	1	(1)
Net temporary differences	(86)	(39)
Net permanent differences	1	1
Total income tax expense	35	50
Effective income tax rate	7.7%	15.1%

[1] Included in current period's amount is the accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.
[2] Impact of tax deductions from deferred tax sharing represents the OEB's prescribed allocation to ratepayers of the net deferred tax asset that originated from the transition from the payments in lieu of tax regime under the *Electricity Act 1998* (Ontario) to tax payments under the federal and provincial tax regime.

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2019	2018
Current income tax expense	27	65
Deferred income tax expense (recovery)	8	(15)
Total income tax expense	35	50

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities that are 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, 2019 and 2018, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2019	2018
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(488)	(362)
Regulatory amounts that are not recognized for tax purposes	(23)	32
Goodwill	(10)	(10)
Post-retirement and post-employment benefits expense in excess of cash payments	352	291
Environmental expenditures	16	22
Non-capital losses	1	1
Other	(6)	(7)
Net deferred income tax liabilities[1]	(158)	(33)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term liabilities.

7. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2019	2018
Accounts receivable – billed	288	262
Accounts receivable – unbilled	344	336
Accounts receivable, gross	632	598
Allowance for doubtful accounts	(22)	(20)
Accounts receivable, net	610	578

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2019 and 2018:

Year ended December 31 *(millions of dollars)*	2019	2018
Allowance for doubtful accounts – beginning	(20)	(29)
Write-offs	17	26
Additions to allowance for doubtful accounts	(19)	(17)
Allowance for doubtful accounts – ending	(22)	(20)

8. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2019	2018
Regulatory assets *(Note 11)*	82	18
Prepaid expenses and other assets	16	11
Materials and supplies	5	5
	103	34

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,922	3,723	82	7,281
Communication	150	134	—	16
Administration and service	1,020	604	30	446
Easements	18	4	—	14
	12,110	4,465	112	7,757

[1] Includes future use assets totalling $53 million.

December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,518	3,538	74	7,054
Communication	144	112	—	32
Administration and service	975	583	25	417
Easements	12	4	—	8
	11,649	4,237	99	7,511

[1] Includes future use assets totalling $50 million.

Financing charges capitalized on property, plant and equipment under construction were $5 million in 2019 (2018 - $5 million).

10. INTANGIBLE ASSETS

December 31, 2019 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	551	295	35	291
Other	52	23	—	29
	603	318	35	320

December 31, 2018 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	492	247	30	275
Other	52	18	—	34
	544	265	30	309

Financing charges capitalized to intangible assets under development were $2 million in 2019 (2018 - $1 million). The estimated annual amortization expense for intangible assets is as follows: 2020 - $49 million; 2021 - $47 million; 2022 - $46 million; 2023 - $37 million; and 2024 - $27 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2019	2018
Regulatory assets:		
Deferred income tax regulatory asset	204	96
Foregone revenue deferral	62	—
Post-retirement and post-employment benefits	57	—
Environmental	45	61
Post-retirement and post-employment benefits non-service cost	33	16
Stock-based compensation	19	21
Distribution system code exemption	—	10
Other	17	18
Total regulatory assets	437	222
Less: current portion	(82)	(18)
	355	204
Regulatory liabilities:		
Distribution rate riders	42	6
Green Energy expenditure variance	31	52
Deferred income tax regulatory liability	25	33
Tax rule changes variance	24	4
Retail settlement variance account	23	39
Pension cost differential	22	38
Earnings sharing mechanism deferral	21	—
Post-retirement and post-employment benefits	—	73
Other	7	13
Total regulatory liabilities	195	258
Less: current portion	(70)	(41)
	125	217

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 Distribution 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 Distribution 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 2019 income tax expense would have been higher by approximately $86 million (2018 - lower by $331 million).

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited 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 a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result, as at December 31, 2018, the Distribution Business recognized an impairment charge of the deferred income tax regulatory asset of $474 million, and an increase in deferred income tax regulatory liability of $33 million. The regulatory balances relating to deferred tax asset sharing will continue to decrease as the tax savings are shared with ratepayers. Notwithstanding the recognition of the effects of the decision in the financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's deferred tax benefit decision. The appeal was heard on November 21, 2019 and a decision is pending.

Foregone Revenue Deferral

The foregone revenue deferral account is primarily made up of the difference between revenue earned based on distribution rates approved by the OEB in Hydro One Networks' 2018-2022 distribution rates application, effective May 1, 2018, and revenue earned under the interim rates until the approved 2018 and 2019 rates were implemented on July 1, 2019. The balance of this account is being recovered from ratepayers over an 18-month period ending December 31, 2020.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Distribution 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 the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2019 OCI would have been lower by $130 million (2018 - higher by $93 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. In 2019, the environmental regulatory asset decreased by $2 million (2018 - $10 million) to reflect related changes in the Distribution Business' PCB and LAR environmental liabilities. 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 Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2019 OM&A expenses would have been lower by $2 million (2018 - $10 million). In addition, 2019 amortization expense would have been lower by $15 million (2018 - $15 million), and 2019 financing charges would have been higher by $1 million (2018 - $3 million).

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks applied to the OEB for a regulatory asset account to record the components other than service costs relating to its post-retirement and post-employment benefits that would have previously been capitalized to property, plant and equipment and intangible assets prior to adoption of ASU 2017-07. In March 2019, the OEB approved the regulatory asset account for the Distribution Business. The Distribution Business has recorded the components other than service costs relating to its post-retirement and post-employment benefits that would have been capitalized to property, plant and equipment and intangible assets, in the Post-Retirement and Post-Employment Benefits Non-Service Cost regulatory asset.

Stock-based Compensation

The Distribution 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, there would be no material impact to OM&A expenses (2018 - OM&A expenses would be higher by $1 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.

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 2015, the OEB also approved Hydro One's request to discontinue this deferral account. The remaining balance in this account at December 31, 2016, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider.

Distribution Rate Riders

In March 2019, as part of its decision on Hydro One Networks' distribution rates application for 2018-2022, the OEB approved the disposition of certain deferral and variance accounts which were accumulated in a 2019-2020 Rate Rider. The Distribution Rate Riders balance includes the 2019-2020 Rate Rider, where amounts are currently being disposed of over an 18-month period ending December 31, 2020, and the 2015-2017 Rate Rider balance, representing over-collected amounts to be returned to ratepayers in a future rate application.

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. The smart grid variance account balance as at December 31, 2016, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting Hydro One Networks to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028. The Budgets measures enacted in the second quarter of 2019 required the Distribution Business to refund the tax benefits related to the accelerated depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the accelerated tax; therefore, the revenue subject to refund cannot be recognized.

Retail Settlement Variance Account (RSVA)

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. The balance as at December 31, 2014, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider.

Pension Cost Differential

Variances between the pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Distribution Business were recognized as a regulatory asset or regulatory liability, as the case may be, prior to January 1, 2018. Variances that were recognized after January 1, 2018 have since been derecognized based on the March 7, 2019 OEB decision. In March 2019, the OEB approved the disposition of the distribution business portion of the balance as at December 31, 2016, including accrued interest, and the balance was transferred to the 2019-2020 Rate Rider. On March 26, 2019, the Company filed a motion to review and vary the OEB's decision as it relates to rates revenue requirement recovery of employer pension costs. Concurrently, the Company filed an appeal with the Ontario Divisional Court. The appeal was held in abeyance pending the outcome of the motion made before the OEB. During the year, the Company reflected a portion of pension costs incurred in the Distribution Business' Pension Cost Differential regulatory account, pending the outcome of the motion before the OEB. On December 19, 2019, the OEB affirmed its earlier decision with respect to recovery of the revenue requirement associated with pension costs. As a result, for the Distribution Business, the Company derecognized the portion relating to pension costs charged to operations as a reversal of revenues of $13 million as this amount is no longer probable for recovery. Hydro One Networks also transferred to property, plant and equipment and intangible assets the portion attributable to capital expenditures in the amount of $37 million. Hydro One has decided to discontinue its appeal of the OEB decision with the Ontario Divisional Court. In the absence of rate-regulated accounting, there would have been no impact to revenue (2018 - revenue would have been higher by $25 million).

Earnings Sharing Mechanism Deferral

In March 2019, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Distribution Business to record over-earnings, if any, realized for any year from 2018 to 2022. Under this mechanism, the Distribution Business shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with distribution ratepayers. This account is asymmetrical to the benefit of ratepayers.

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2019	2018
Accrued liabilities	651	588
Accounts payable	67	53
Accrued interest *(Note 23)*	42	38
Regulatory liabilities *(Note 11)*	70	41
Lease obligations *(Note 20)*	4	—
	834	720

13. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2019	2018
Post-retirement and post-employment benefit liability *(Note 17)*	947	781
Lease obligations *(Note 20)*	33	—
Environmental liabilities *(Note 18)*	31	48
Long-term inter-company payable *(Note 23)*	15	17
Long-term accounts payable and other liabilities	4	5
Asset retirement obligations *(Note 19)*	5	5
	1,035	856

14. 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 Distribution Business outstanding at December 31, 2019 and 2018:

December 31 *(millions of dollars)*	2019	2018
Long-term debt	4,245	3,921
Add: Net unamortized debt premiums	6	7
Add: Unrealized mark-to-market gain[1]	—	(2)
Less: Deferred debt issuance costs	(16)	(15)
Less: Long-term debt payable within one year	(150)	(291)
Long-term debt	4,085	3,620

[1] The unrealized mark-to-market net gain in 2018 relates to $30 million of notes due in 2020 and $200 million notes due in 2019. The unrealized mark-to-market net gain in 2018 was offset by $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.

In 2019, Hydro One issued $1,500 million (2018 - $1,400 million) of long-term debt under its MTN Program, all of which was mirrored down to Hydro One Networks, and $615 million was allocated to the Distribution Business.

In 2019, Hydro One repaid $728 million (2018 - $750 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $728 million (2018 - $750 million) to Hydro One, of which $291 million (2018 - $337 million) was allocated to the Distribution Business.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

Years	Long-Term Debt Principal Repayments *(millions of dollars)*	Interest Payments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
2020	150	179	3.9
2021	250	174	2.1
2022	261	167	3.2
2023	—	163	—
2024	287	158	2.8
	948	841	2.9
2025-2029	602	725	3.2
2030 and thereafter	2,695	1,641	5.0
	4,245	3,207	4.3

15. 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 Distribution Business 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, 2019 and 2018, 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 Distribution Business' long-term debt at December 31, 2019 and 2018 are as follows:

December 31 *(millions of dollars)*	2019 Carrying Value	2019 Fair Value	2018 Carrying Value	2018 Fair Value
$200 million notes due 2019	—	—	198	198
$30 million notes due 2020	30	30	30	30
Other notes and debentures	4,205	4,946	3,683	4,028
Long-term debt, including current portion	4,235	4,976	3,911	4,256

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, 2019, the Distribution Business' share of the Company's derivative instruments included $30 million (2018 - $230 million) interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was approximately 1% (2018 - 6%) of its total long-term debt. At December 31, 2019, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- a $30 million fixed-to-floating interest-rate swap agreement to convert $30 million of the $350 million notes maturing April 30, 2020 into three-month variable rate debt.

At December 31, 2019 and 2018, 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, 2019 and 2018 is as follows:

December 31, 2019 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	4,235	4,976	—	4,976	—
	4,235	4,976	—	4,976	—

December 31, 2018 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	3,911	4,256	—	4,256	—
Derivative instruments - fair value hedges (interest-rate swaps)[1]	2	2	—	2	—
	3,913	4,258	—	4,258	—

[1] Derivative liabilities are included in other long-term liabilities on the balance sheets.

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, 2019 or 2018.

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 may utilize interest-rate swaps 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 Distribution Business' net income for the years ended December 31, 2019 and 2018.

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 net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2019 and 2018 were 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, 2019 and 2018, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. At December 31, 2019 and 2018, there was no material accounts receivable balance due from any single customer.

At December 31, 2019, the Company's allowance for doubtful accounts was $22 million (2018 - $20 million). The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2019, approximately 5% (2018 - 5%) of the Distribution Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution 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, 2019 and 2018, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2019, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with three 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 operating 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.

16. CAPITAL MANAGEMENT

The Distribution 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, 2019 and 2018, the Distribution Business' capital structure was as follows:

December 31 *(millions of dollars)*	2019	2018
Long-term debt payable within one year	150	291
Inter-company demand facility	303	392
	453	683
Long-term debt	4,085	3,620
Excess of assets over liabilities	2,635	2,716
Total capital	7,173	7,019

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2019 and 2018:

Year ended December 31 *(millions of dollars)*	2019	2018
Excess of assets over liabilities - beginning	2,716	2,768
Net income	418	281
Payments to Hydro One to finance dividends and return of stated capital	(496)	(333)
Other[1]	(3)	—
Excess of assets over liabilities - ending	2,635	2,716

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Distribution Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Distribution Business, resulting in an impact to excess of assets over liabilities.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a 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 up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Distribution Business contributions to the DC Plan for the year ended December 31, 2019 were less than $1 million (2018 - less than $1 million).

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 the highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the 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 reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total annual cash Pension Plan employer contributions for 2019 were $61 million (2018 - $75 million). Estimated annual Pension Plan employer contributions for the years 2020, 2021, 2022, 2023 and 2024 are approximately $66 million, $65 million, $64 million, $64 million, and $64 million, respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the 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, 2019, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,973 million (2018 - $7,752 million). The fair value of pension plan assets available for these benefits was $7,848 million (2018 - $7,205 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2019, the Distribution Business charged $31 million (2018 - $33 million) of post-retirement and post-employment benefit costs to operation, maintenance and administration expenses, and capitalized $34 million (2018 - $31 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2019 were $26 million (2018 - $27 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was increased by $130 million (2018 - decreased by $93 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

December 31 *(millions of dollars)*	2019	2018
Accrued liabilities	30	27
Post-retirement and post-employment benefit liability	947	781
Net unfunded status	977	808

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2019 and 2018:

Year ended December 31, 2019 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	45	16	61
Interest accretion	1	—	1
Expenditures	(12)	(3)	(15)
Revaluation adjustment	(1)	(1)	(2)
Environmental liabilities - ending	33	12	45
Less: current portion	(8)	(6)	(14)
	25	6	31

Year ended December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	61	22	83
Interest accretion	2	1	3
Expenditures	(10)	(5)	(15)
Revaluation adjustment	(8)	(2)	(10)
Environmental liabilities - ending	45	16	61
Less: current portion	(9)	(4)	(13)
	36	12	48

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, 2019 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	36	13	49
Less: discounting environmental liabilities to present value	(3)	(1)	(4)
Discounted environmental liabilities	33	12	45

December 31, 2018 *(millions of dollars)*	PCB	LAR	Total
Undiscounted environmental liabilities	49	16	65
Less: discounting environmental liabilities to present value	(4)	—	(4)
Discounted environmental liabilities	45	16	61

At December 31, 2019, the estimated future environmental expenditures were as follows:

December 31 *(millions of dollars)*	2019
2020	14
2021	13
2022	11
2023	10
2024	1
Thereafter	—
	49

The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution 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 Distribution Business' 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 parts per million.

At December 31, 2019, the Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations was $36 million (2018 - $49 million). These expenditures are expected to be incurred over the period from 2020 to 2024. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2019 to decrease the PCB environmental liability by $1 million (2018 - $8 million).

LAR

At December 31, 2019, the Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program was $12 million (2018 - $16 million). These expenditures are expected to be incurred over the period from 2020 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2019 to decrease the LAR environmental liability by $1 million (2018 - $2 million).

19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures required to remove and dispose 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 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution 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. Changes in estimates are accounted for prospectively. As a result of its annual review of asset retirement obligations, no revaluation adjustment to the asset retirement obligations was recorded in 2019 in the Distribution Business (2018 - revaluation adjustment was recorded to increase the asset retirement obligations by $1 million).

At December 31, 2019, Hydro One Networks had recorded asset retirement obligations of $5 million (2018 - $5 million) related to the Distribution 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.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and seven years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. 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. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Company's operating leases was as follows:

Year ended December 31 *(millions of dollars)*	2019
Lease expense	4
Lease payments made	3

December 31	2019
Weighted-average remaining lease term[1] *(years)*	8
Weighted-average discount rate	2.7%

[1] Includes renewal options that are reasonably certain to be exercised.

At December 31, 2019, future minimum operating lease payments were as follows:

December 31 *(millions of dollars)*	2019
2020	5
2021	6
2022	5
2023	5
2024	5
Thereafter	16
Total undiscounted minimum lease payments[1]	42
Less: discounting minimum lease payments to present value	(5)
Total discounted minimum lease payments	37

[1] Excludes committed amounts of $3 million for leases that have not yet commenced.

At December 31, 2018, future minimum operating lease payments were as follows:

December 31 *(millions of dollars)*	2018
2019	3
2020	5
2021	2
2022	1
2023	1
2024	—
Thereafter	2
Total undiscounted minimum lease payments	14

Hydro One presents its ROU assets and lease obligations on the balance sheet as follows:

December 31 *(millions of dollars)*	2019
Right-of-Use assets	36
Accounts payable and other current liabilities *(Note 12)*	4
Other long-term liabilities *(Note 13)*	33

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2019 and 2018, Hydro One Networks had 209,401,289 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2019, Hydro One Networks declared common share dividends in the amount of $1 million (2018 - $1 million) and made a return of stated capital of $738 million (2018 – $545 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends and return of stated capital was $496 million (2018 - $333 million).

22. 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 Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an inter-company 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 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 Initial Public Offering (IPO). 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, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution 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 Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 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 2019, 228,916 common shares were issued under the Share Grant Plans (2018 - 248,109) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2019 was $4 million (2018 - $6 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during years ended December 31, 2019 and 2018 is presented below:

Year ended December 31, 2019	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,295,874	$20.50
Vested and issued[1]	(228,916)	—
Forfeited	(46,992)	$20.50
Share grants outstanding - ending	2,019,966	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2018	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,599,170	$20.50
Vested and issued[1]	(248,109)	—
Forfeited	(55,187)	$20.50
Share grants outstanding - ending	2,295,874	$20.50

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

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 Board of Directors.

During 2019 and 2018, Directors' DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2019	2018
DSUs outstanding - beginning	41,107	74,268
Granted	7,993	19,457
Settled	(6,412)	(52,618)
DSUs outstanding - ending	42,688	41,107

For the years ended December 31, 2019 and 2018, the expense related to the Directors' DSU Plan was not significant. At December 31, 2019 and 2018, the liability related to Directors' DSUs was not significant.

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 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 Board of Directors.

During 2019 and 2018, Management DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2019	2018
DSUs outstanding - beginning	33,902	25,162
Granted	5,308	8,740
Other[1]	(25,725)	—
DSUs outstanding - ending	13,485	33,902

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

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 2019, Company contributions made under the ESOP and allocated to the Distribution Business were $1 million (2018 - $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 which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. 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 Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2019 and 2018, LTIP awards granted by Hydro One Limited that related to the Distribution Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2019	2018	2019	2018
Units outstanding – beginning	232,132	168,490	156,215	151,490
Granted	—	128,364	—	97,207
Vested and issued[1]	(10,837)	(56)	(21,717)	(45,139)
Forfeited	(4,750)	(13,656)	(4,075)	(13,184)
Settled	—	(51,010)	—	(34,159)
Other[2]	(174,795)	—	(93,731)	—
Units outstanding – ending	41,750	232,132	36,692	156,215

[1] In 2019 and 2018, Hydro One Limited issued from treasury common shares to eligible Distribution Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

No awards were granted in 2019. The grant date total fair value of the awards granted in 2018 was $5 million. The compensation expense related to the PSU and RSU awards recognized by the Distribution Business during 2019 was not significant (2018 - $4 million).

At December 31, 2019, payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant (2018 - $4 million).

On February 13, 2020, 8,941 PSUs were vested and issued. See Note 27 - Subsequent Events.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. No stock options were granted in 2019 (2018 - 1,450,880 stock options were granted). The stock options granted are exercisable for a period not to exceed seven years from the date of grant.

The fair value-based method is used to measure compensation expense related to stock options and the expense is recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model.

Stock options granted and the weighted-average assumptions used in the valuation model for options granted during 2018 are as follows:

Exercise price[1]	$ 20.70
Grant date fair value per option	$ 1.66
Valuation assumptions:	
Expected dividend yield[2]	3.78%
Expected volatility[3]	15.01%
Risk-free interest rate[4]	2.00%
Expected option term[5]	4.5 years

[1] Hydro One Limited common share price on the date of the grant.
[2] Based on dividend and Hydro One Limited common share price on the date of the grant.
[3] Based on average daily volatility of Hydro One Limited's peer entities for a 4.5-year term.
[4] Based on bond yield for an equivalent Canadian government bond.
[5] Determined using the option term and the vesting period.

During 2018, the activity of stock options granted by Hydro One Limited that related to the Distribution Business was as follows:

	Number of Stock Options	Weighted-average exercise price
Stock options outstanding - January 1, 2018	—	
Granted	391,118	$ 20.70
Forfeited	(54,604)	$ 20.66
Stock options outstanding - December 31, 2018	336,514	$ 20.72
Other[1]	(336,514)	
Stock options outstanding - December 31, 2019	—	

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

23. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2019. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. The following is a summary of the Distribution Business related party transactions during the years ended December 31, 2019 and 2018:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2019	2018
IESO	Power purchased	1,808	1,636
	Amounts related to electricity rebates	689	475
	Distribution revenues related to rural rate protection	240	239
	Funding received related to Conservation and Demand Management programs	42	62
OPG	Power purchased	8	10
	Revenues related to supply of electricity	6	6
OEFC	Power purchased from power contracts administered by the OEFC	2	2
OEB	OEB fees	5	4
Hydro One Limited and its subsidiaries	Revenues for services provided	4	2
	Services received - costs expensed	10	12
	Interest expense on long-term debt	181	168
	Interest expense on inter-company demand facility	6	4
	Payments to finance dividends and return of stated capital	496	333
	Stock-based compensation costs	5	10

The amounts due to and from related parties at December 31, 2019 and 2018 are as follows:

December 31 *(millions of dollars)*	2019	2018
Inter-company demand facility	(303)	(392)
Due from related parties	278	125
Due to related parties	(302)	(84)
Accrued interest	(42)	(38)
Long-term inter-company payable	(15)	(17)
Long-term debt, including current portion	(4,235)	(3,911)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2019	2018
Accounts receivable	(32)	10
Due from related parties	(153)	(6)
Materials and supplies	—	(1)
Other assets	(5)	2
Accounts payable	11	(10)
Accrued liabilities	63	29
Due to related parties	218	(68)
Accrued interest	4	(2)
Long-term accounts payable and other liabilities	1	(1)
Post-retirement and post-employment benefit liability	19	20
	126	(27)

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2019 and 2018. The reconciling items include change in accruals and capitalized depreciation.

Year ended December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(560)	(60)	(620)
Reconciling items	20	1	21
Cash outflow for capital expenditures	(540)	(59)	(599)

Year ended December 31, 2018 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(497)	(76)	(573)
Reconciling items	14	1	15
Cash outflow for capital expenditures	(483)	(75)	(558)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2019	2018
Net interest paid	177	170
Income taxes paid	17	70

25. 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, were defendants in a class action suit commenced in 2015 in which the representative plaintiff was seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's application for leave to appeal the lower court's refusal to certify the lawsuit as a class action was denied by the Ontario Court of Appeal on March 26, 2019, which means that the lawsuit has effectively ended.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

26. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

27. SUBSEQUENT EVENTS

Payments to Finance Return of Stated Capital

On February 20, 2020, Hydro One Networks declared a return of stated capital of $146 million. The amount allocated to the Distribution Business to finance this payment was $66 million.

Long-term Debt

On February 28, 2020, Hydro One issued $1,100 million of long-term debt under its MTN Program, $753 million of which was mirrored down to Hydro One Networks, and $211 million was allocated to the Distribution Business.

Stock-based Compensation

Subsequent to December 31, 2019, Hydro One Limited issued from treasury 8,941 and 216,822 common shares to eligible Distribution Business employees in accordance with provisions of the LTIP Plan and Share Grant Plans, respectively.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2020

INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2020
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve-out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2020 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Accounting and Basis of Preparation

We draw attention to Note 2 in the financial statements which describes the basis of accounting and basis of preparation used in these financial statements and the purpose of the financial statements.

As a result, the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 15, 2021

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2020 and 2019

Year ended December 31 *(millions of Canadian dollars)*	**2020**	**2019**
Revenues		
Energy sales	5,109	4,448
Rural rate protection *(Note 23)*	242	240
Other	35	44
	5,386	4,732
Costs		
Purchased power *(Note 23)*	3,796	3,111
Operation, maintenance and administration *(Note 23)*	571	572
Depreciation, amortization and asset removal costs *(Note 4)*	417	407
	4,784	4,090
Income before financing charges and income tax expense	**602**	**642**
Financing charges *(Notes 5, 23)*	188	189
Income before income tax expense	**414**	**453**
Income tax expense (recovery) *(Note 6)*	(1)	35
Net income	**415**	**418**
Other comprehensive loss *(Note 17)*	(6)	—
Comprehensive income	**409**	**418**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2020 and 2019

As at December 31 *(millions of Canadian dollars)*	**2020**	**2019**
Assets		
Current assets:		
Inter-company demand facility *(Note 23)*	107	—
Accounts receivable *(Note 7)*	604	610
Due from related parties *(Note 23)*	183	278
Other current assets *(Note 8)*	46	103
	940	991
Property, plant and equipment *(Note 9)*	8,092	7,757
Other long-term assets:		
Regulatory assets *(Note 11)*	922	355
Intangible assets *(Note 10)*	342	320
Goodwill	168	168
Right-of-Use assets *(Note 20)*	34	36
	1,466	879
Total assets	**10,498**	**9,627**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	—	303
Long-term debt payable within one year *(Notes 14, 15, 23)*	250	150
Accounts payable and other current liabilities *(Note 12)*	736	834
Due to related parties *(Note 23)*	321	302
	1,307	1,589
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	4,500	4,085
Deferred income tax liabilities *(Note 6)*	668	158
Regulatory liabilities *(Note 11)*	169	125
Other long-term liabilities *(Note 13)*	1,084	1,035
	6,421	5,403
Total liabilities	**7,728**	**6,992**
Contingencies and Commitments *(Notes 25, 26)*		
Subsequent Events *(Note 27)*		
Excess of assets over liabilities *(Notes 16, 21)*	2,770	2,635
Total liabilities and excess of assets over liabilities	**10,498**	**9,627**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Russel Robertson
Chair, Audit Committee

Mark Poweska
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2020 and 2019

Year ended December 31 *(millions of Canadian dollars)*	2020	2019
Operating activities		
Net income	415	418
Environmental expenditures	(14)	(15)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	356	352
Regulatory assets and liabilities	126	(33)
Deferred income tax expense (recovery)	(92)	8
Other	27	7
Changes in non-cash balances related to operations *(Note 24)*	42	126
Net cash from operating activities	**860**	**863**
Financing activities		
Long-term debt issued	667	615
Long-term debt repaid	(150)	(291)
Payments to finance dividends and return on stated capital	(274)	(496)
Other	(3)	(2)
Net cash from (used in) financing activities	**240**	**(174)**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(614)	(540)
Intangible assets	(70)	(59)
Other	(6)	(1)
Net cash used in investing activities	**(690)**	**(600)**
Net change in inter-company demand facility	410	89
Inter-company demand facility, beginning of year	(303)	(392)
Inter-company demand facility, end of year	**107**	**(303)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

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 Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On March 7, 2019, the OEB issued its reconsideration decision (DTA Decision) with respect to Hydro One's rate-setting treatment of the benefits of the deferred tax asset resulting from the transition from the payments in lieu of tax regime to tax payments under the federal and provincial tax regimes. On July 16, 2020, the Ontario Divisional Court rendered its decision on the Company's appeal of the OEB's DTA Decision. See Note 11 - Regulatory Assets and Liabilities.

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. On March 7, 2019, the OEB rendered its decision on the distribution rates application. In accordance with the OEB decision, the Company filed its draft rate order reflecting updated revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022. On June 11, 2019, the OEB approved the rate order confirming these updated revenue requirements.

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), with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2020 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Distribution Business. 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 Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution 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 Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution 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 Distribution Business was a separate taxpaying entity. These Financial Statements include deferred taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. 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 15, 2021, 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 27 - 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, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.

As the COVID-19 pandemic (COVID-19 or the pandemic) has resulted in incremental operating costs and lost revenues, the Company has also analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no material impact. Additional details regarding the impact of the pandemic on the Financial Statements are available in Note 7 - Accounts Receivable and Note 11 - Regulatory Assets and Liabilities.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Distribution Business' financial results and operations.

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 Distribution 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Distribution 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 Distribution 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 prospectively from the date the assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Revenue Recognition

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, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' current lifetime expected credit losses (CECL) for all accounts receivable balances. The Distribution Business estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. 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.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year’s taxable income. 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 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.

Deferred Income Taxes

Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including 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 associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

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.

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 Distribution 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 0.15%. 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, and information technology (IT). 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 distribution, administration and service, and other communication assets as well as 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.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Other

Other assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include 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 Distribution 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 Distribution Business' 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, 2015 for Distribution 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:			
Distribution	46 years	1% - 7%	2%
Communication	8 years	1% - 15%	11%
Administration and service	21 years	1% - 20%	4%
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 quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the 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 the assessment performed as at September 30, 2020 and with no significant events since, the Company has concluded that goodwill was not impaired at December 31, 2020.

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 Distribution 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.

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, 2020 and 2019, no asset impairment had been recorded for assets within the Distribution Business.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Distribution Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred 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 / Loss

Comprehensive income/loss is comprised of net income/loss and other comprehensive income (OCI) or other comprehensive loss (OCL). OCI/OCL and net income are presented in a single continuous statement of operations and comprehensive income/loss.

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 its net realizable value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Distribution Business 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. The Distribution Business estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

The Distribution Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Distribution Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Distribution Business' risk management policy disclosed in Note 15 - 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, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. 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 that required bifurcation at December 31, 2020 or 2019.

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 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 plan (Pension Plan) and its 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 (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO 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 PBO of the plan, an asset is recognized equal to the net overfunded PBO. 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 (DC 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 (OM&A) 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.

<u>Post-retirement and Post-employment Benefits</u>

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 reflective of earnings allocations of relevant employees to the Company's Distribution Business.

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 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 benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's 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 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 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the 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 Distribution 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 Distribution 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 Distribution Business records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. 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. This uncertainty is incorporated in the fair value measurement of the obligation.

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. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. 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 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 Distribution 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 Distribution 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.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a re-measurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Distribution Business
ASU 2017-04	January 2017	The amendment removes the second step of the previous two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	No impact upon adoption
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Distribution Business
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-01	January 2020	The amendments clarify the interaction of the accounting for equity securities under Topic 321, investments under the equity method of accounting in Topic 323 and the accounting for certain forward contracts and purchased options accounted for under Topic 815.	January 1, 2021	No impact upon adoption
ASU 2020-06	August 2020	The update addresses the complexity associated with applying GAAP for certain financial instruments with characteristics of liabilities and equity. The amendments reduce the number of accounting models for convertible debt instruments and convertible preferred stock.	January 1, 2022	Under assessment
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2020	2019
Depreciation of property, plant and equipment	290	280
Amortization of intangible assets	52	57
Amortization of regulatory assets	14	15
Depreciation and amortization	356	352
Asset removal costs	61	55
	417	407

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2020	2019
Interest on long-term debt *(Note 23)*	185	181
Interest on inter-company demand facility *(Note 23)*	2	6
Other	9	9
Less: Interest capitalized on construction and development in progress	(8)	(7)
	188	189

6. INCOME TAXES

As a rate regulated utility business, the Distribution Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Distribution Business' tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Distribution Business' income tax expense or recovery 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)*	2020	2019
Income before income tax expense	414	453
Income tax expense at statutory rate of 26.5% (2019 - 26.5%)	110	120
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization[1]	(32)	(35)
Impact of tax deductions from deferred tax asset sharing[2]	(17)	(34)
Overheads capitalized for accounting but deducted for tax purposes	(9)	(8)
Environmental expenditures	(4)	(4)
Pension and post-retirement benefit contributions in excess of expense	(3)	(4)
Interest capitalized for accounting but deducted for tax purposes	(2)	(2)
Other	(1)	1
Net temporary differences attributable to regulated business	(68)	(86)
Net permanent differences	—	1
Recognition of deferred income tax regulatory asset *(Note 11)*	(43)	—
Total income tax expense (recovery)	(1)	35
Effective income tax rate	(0.2)%	7.7 %

[1] Includes accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.
[2] Prior to the ODC Decision, the impact represents tax deductions from deferred asset tax sharing given to ratepayers as previously mandated by the OEB. Subsequent to the ODC Decision, the impact represents the recovery of deferred tax asset sharing currently allocated to rate-payers. See Note 11 - Regulatory Assets and Liabilities.

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2020	2019
Current income tax expense	91	27
Deferred income tax expense (recovery)	(92)	8
Total income tax expense (recovery)	(1)	35

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Distribution Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and liabilities consisted of the following:

As at December 31 *(millions of dollars)*	2020	2019
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,041)	(488)
Goodwill	(11)	(10)
Regulatory assets and liabilities	(7)	(23)
Post-retirement and post-employment benefits expense in excess of cash payments	383	352
Environmental expenditures	14	16
Non-capital losses	1	1
Other	(7)	(6)
Net deferred income tax liabilities[1]	(668)	(158)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term liabilities.

7. ACCOUNTS RECEIVABLE

As at December 31 *(millions of dollars)*	2020	2019
Accounts receivable – billed	309	288
Accounts receivable – unbilled	339	344
Accounts receivable, gross	648	632
Allowance for doubtful accounts	(44)	(22)
Accounts receivable, net	604	610

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2020 and 2019:

Year ended December 31 *(millions of dollars)*	2020	2019
Allowance for doubtful accounts – beginning	(22)	(20)
Write-offs	11	17
Additions to allowance for doubtful accounts[1]	(33)	(19)
Allowance for doubtful accounts – ending	(44)	(22)

[1] Additions to allowance for doubtful accounts for the year ended December 31, 2020 include incremental $14 million related to the COVID-19 pandemic which were recognized in OM&A in 2020 (2019 - $nil).

8. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	2020	2019
Regulatory assets *(Note 11)*	21	82
Prepaid expenses and other assets	20	16
Materials and supplies	5	5
	46	103

9. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2020 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	11,376	3,920	95	7,551
Administration and service	1,089	620	55	524
Other	176	159	—	17
	12,641	4,699	150	8,092

[1] Includes future use assets totalling $61 million.

As at December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,922	3,723	82	7,281
Administration and service	1,020	604	30	446
Other	168	138	—	30
	12,110	4,465	112	7,757

[1] Includes future use assets totalling $53 million.

Financing charges capitalized on property, plant and equipment under construction were $6 million in 2020 (2019 - $5 million).

10. INTANGIBLE ASSETS

As at December 31, 2020 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	631	343	30	318
Other	52	28	—	24
	683	371	30	342

As at December 31, 2019 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	551	295	35	291
Other	52	23	—	29
	603	318	35	320

Financing charges capitalized to intangible assets under development were $2 million in 2020 (2019 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2021 - $55 million; 2022 - $54 million; 2023 - $44 million; 2024 - $35 million; and 2025 - $33 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2020	2019
Regulatory assets:		
Deferred income tax regulatory asset	697	192
Deferred tax asset sharing	70	—
Post-retirement and post-employment benefits non-service cost	68	45
Environmental	39	45
Post-retirement and post-employment benefits	32	57
Stock-based compensation	21	19
Foregone revenue deferral	—	62
Other	16	17
Total regulatory assets	943	437
Less: current portion	(21)	(82)
	922	355

Regulatory liabilities:		
Retail settlement variance account	92	23
Tax rule changes variance	48	24
Earnings sharing mechanism deferral	37	21
Pension cost differential	24	22
Green energy expenditure variance	22	31
Distribution rate riders	1	42
Deferred income tax regulatory liability	—	25
Other	9	7
Total regulatory liabilities	233	195
Less: current portion	(64)	(70)
	169	125

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 Distribution 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 Distribution 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 2020 income tax expense would have been higher by approximately $69 million (2019 - higher by $86 million), of which $52 million is included in Deferred Income Tax Regulatory Asset and Liability with the remaining $17 million included in Deferred Tax Asset Sharing.

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited 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 have resulted in an impairment of a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its DTA Decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result, as at December 31, 2018, the Company recorded impairment charges relating to Hydro One Networks' distribution and transmission deferred income tax regulatory asset. Notwithstanding the recognition of the effects of the DTA Decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's DTA Decision. The appeal was heard on November 21, 2019.

On July 16, 2020, the Ontario Divisional Court rendered its decision (ODC Decision) on the Company's appeal of the OEB's DTA Decision.

In connection with the ODC Decision, the Distribution Business recorded a reversal of the previously recognized impairment charge of the deferred income tax regulatory asset in its financial statements for the year ended December 31, 2020. The reversal of the previously recognized impaired charge included the regulatory asset relating to the cumulative deferred tax asset amounts shared with ratepayers (deferred tax asset sharing) up to and including June 30, 2020 by the Distribution Business of $58 million. The Distribution Business recognized deferred income tax regulatory assets of $504 million and associated deferred income tax liability of $462 million. The Distribution Business also recorded an increase in net income of $43 million as deferred income tax recovery during the year ended December 31, 2020.

Deferred Tax Asset Sharing

On October 2, 2020, the OEB issued a procedural order to implement the direction of the Ontario Divisional Court and required Hydro One to submit its proposal for the recovery of the deferred tax asset amounts allocated to ratepayers for the 2018 to 2022 period. As at December 31, 2020, the Distribution Business recorded a regulatory asset of $70 million for the cumulative deferred tax asset amounts shared with ratepayers since 2018 to date. As a result of the OEB's procedural order, the $70 million regulatory asset relating to the cumulative deferred tax asset amounts allocated to ratepayers since 2018 has been separately presented from the deferred income tax regulatory asset. Additional amounts shared with ratepayers up to December 31, 2021 will continue to increase this regulatory asset. On April 8, 2021, the OEB rendered its decision and order regarding the recovery of the deferred tax asset amounts allocated to ratepayers for the 2018 to 2022 period (Implementation Decision). In its decision, the OEB approved recovery of the deferred tax asset amounts allocated to ratepayers for the 2018 to 2021 period including the $70 million at December 31, 2020. See Note 27 – Subsequent Events for additional information.

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. As part of Hydro One Networks' 2020-2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's other post-employment benefits (OPEB) costs shall be recognized as OM&A for the Distribution Business. The Distribution Business continues to record the non-serivce cost component of OPEBs in this account until its next rebasing application.

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. In 2020, the environmental regulatory asset increased by $7 million (2019 - decreased by $2 million) to reflect related changes in the Distribution Business' PCB and LAR environmental liabilities. 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 Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2020 OM&A expenses would have been higher by $7 million (2019 - lower by $2 million). In addition, 2020 amortization expense would have been lower by $14 million (2019 - $15 million), and 2020 financing charges would have been higher by $1 million (2019 - $1 million).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Distribution 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 the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2020 OCL would have been lower by $25 million (2019 - OCI lower by $130 million).

Stock-based Compensation

The Distribution 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, there would be no material impact to OM&A expenses in 2020 and 2019. 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

The foregone revenue deferral account was made up of the difference between revenue earned based on distribution rates approved by the OEB in Hydro One Networks' 2018-2022 distribution rates application, effective May 1, 2018, and revenue earned under the interim rates until the approved 2018 and 2019 rates were implemented on July 1, 2019. This amount was recovered from ratepayers over an 18-month period ending December 31, 2020.

Retail Settlement Variance Account (RSVA)

The Distribution business has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. The balance as at December 31, 2014, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider. The balance as at December 31, 2019, including accrued interest, was approved for disposition over a one year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting the Distribution Business to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities, including the Distribution Business to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized.

Earnings Sharing Mechanism Deferral

In March 2019, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Distribution Business to record over-earnings including tax impacts, if any, realized for any year from 2018 to 2022. Under this mechanism, the Distribution Business shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with distribution ratepayers. This account is asymmetrical to the benefit of ratepayers. The balance as at December 31, 2019, including accrued interest, was approved for disposition on an interim basis over a one year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application.

Pension Cost Differential

Variances between the pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Distribution Business were recognized as a regulatory asset or regulatory liability, as the case may be. Variances into the account were not recognized for the Distribution Business in 2019 in accordance with the OEB's decision on the motion to review and vary the OEB's decision as it relates to rates revenue requirement recovery of employer pension costs. In March 2019, the OEB approved the disposition of the distribution business portion of the balance as at December 31, 2016, including accrued interest, and the balance was transferred to the 2019-2020 Rate Rider. In the absence of rate-regulated accounting, 2020 revenue would have been higher by $1 million (2019 - no impact to revenue).

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. The smart grid variance account balance as at December 31, 2016, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider.

Distribution Rate Riders

In March 2019, as part of its decision on Hydro One Networks' distribution rates application for 2018-2022, the OEB approved the disposition of certain deferral and variance accounts which were accumulated in a 2019-2020 Rate Rider. The Distribution Rate Riders balance includes the 2019-2020 Rate Rider, where amounts were returned to ratepayers over an 18-months period ending December 31, 2020. There is a balance in the 2019-2020 Rate Rider that remains which represents amounts that shall be collected from ratepayers in a future rate application. This amount is largely offset by the 2015-2017 Rate Rider balance, which was approved for disposition over a one year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application.

COVID-19 Emergency Deferral

The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from Postponing Rate Implementation, and (v) Bad Debt.

On December 16, 2020, the OEB Staff released their proposal on the COVID-19 deferral accounts which introduces certain criteria that may need to be satisfied for amounts to be eligible for recovery. Based on Hydro One Networks' interpretation of the OEB Staff's proposal, the Distribution Business has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory asset. The Distribution Business continues to track certain incremental costs and lost revenues that have arisen due to the COVID-19 pandemic.

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	2020	2019
Accrued liabilities	527	637
Accounts payable	81	67
Accrued interest *(Note 23)*	45	42
Regulatory liabilities *(Note 11)*	64	70
Environmental liabilities *(Note 18)*	14	14
Lease obligations *(Note 20)*	5	4
	736	834

13. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	2020	2019
Post-retirement and post-employment benefit liability *(Note 17)*	1,000	947
Lease obligations *(Note 20)*	32	33
Environmental liabilities *(Note 18)*	25	31
Long-term inter-company payable *(Note 23)*	17	15
Long-term accounts payable and other liabilities	4	4
Asset retirement obligations *(Note 19)*	6	5
	1,084	1,035

14. 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 Distribution Business outstanding at December 31, 2020 and 2019:

As at December 31 *(millions of dollars)*	2020	2019
Long-term debt	4,762	4,245
Add: Net unamortized debt premiums	6	6
Less: Deferred debt issuance costs	(18)	(16)
Less: Long-term debt payable within one year	(250)	(150)
Long-term debt	4,500	4,085

In 2020, Hydro One issued $2,300 million long-term debt under its MTN Program (2019 - $1,500 million), of which $1,953 million was mirrored down to Hydro One Networks, and $667 million was allocated to the Distribution Business.

In 2020, Hydro One repaid $650 million (2019 - $728 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $330 million (2019 - $728 million) to Hydro One, of which $150 million (2019 - $291 million) was allocated to the Distribution Business.

Principal and Interest Payments

At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments *(millions of dollars)*	Interest Payments *(millions of dollars)*	Weighted-Average Interest Rate *(%)*
Year 1	250	185	2.1
Year 2	261	180	3.2
Year 3	228	174	1.0
Year 4	287	169	2.8
Year 5	208	162	2.8
	1,234	870	2.4
Years 6-10	669	746	3.8
Thereafter	2,859	1,589	4.7
	4,762	3,205	4.0

15. 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 Distribution Business 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, 2020 and 2019, 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 Distribution Business' long-term debt at December 31, 2020 and 2019 are as follows:

As at December 31 *(millions of dollars)*	2020 Carrying Value	2020 Fair Value	2019 Carrying Value	2019 Fair Value
$30 million notes due 2020	—	—	30	30
Other notes and debentures	4,750	5,861	4,205	4,946
Long-term debt, including current portion	4,750	5,861	4,235	4,976

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, 2020, the Distribution Business' share of the Company's derivative instruments was $nil. At December 31, 2019, the Distribution Business' share of the Company's derivative instruments included $30 million interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps were classified as fair value hedges. At December 31, 2019, the Distribution Business' fair value hedge exposure was approximately 1% of its total long-term debt.

At December 31, 2020 and 2019, 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, 2020 and 2019 is as follows:

As at December 31, 2020 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	4,750	5,861	—	5,861	—
	4,750	5,861	—	5,861	—

As at December 31, 2019 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	4,235	4,976	—	4,976	—
	4,235	4,976	—	4,976	—

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, 2020 or 2019.

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 values, 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.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. 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. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Distribution Business' net income for the years ended December 31, 2020 and 2019.

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 net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2020 and 2019 were 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, 2020 and 2019, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. At December 31, 2020 and 2019, there was no material accounts receivable balance due from any single customer.

At December 31, 2020, the Distribution Business' allowance for doubtful accounts was $44 million (2019 - $22 million). The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2020, approximately 4% (2019 - 5%) of the Distribution Business' net accounts receivable were outstanding for more than 60 days. Please see Note 7 - Accounts Receivable for additions to allowance for doubtful accounts related to the impact of the COVID-19 pandemic.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution 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 maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2020 and 2019, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2020, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, was with four financial institutions with investment grade credit ratings as 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 operating 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. The Company's currently available liquidity is also expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Company's cash requirements.

16. CAPITAL MANAGEMENT

The Distribution 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, 2020 and 2019, the Distribution Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	2020	2019
Long-term debt payable within one year	250	150
Inter-company demand facility	(107)	303
	143	453
Long-term debt	4,500	4,085
Excess of assets over liabilities	2,770	2,635
Total capital	7,413	7,173

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31 *(millions of dollars)*	2020	2019
Excess of assets over liabilities - beginning	2,635	2,716
Net income	409	418
Payments to Hydro One to finance dividends and return of stated capital	(274)	(496)
Other[1]	—	(3)
Excess of assets over liabilities - ending	2,770	2,635

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Distribution Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Distribution Business, resulting in an impact to excess of assets over liabilities.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a 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 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 up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. The Distribution Business contributions to the DC Plan for the year ended December 31, 2020 were $1 million (2019 - less than $1 million).

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 United Professionals (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 reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total annual cash Pension Plan employer contributions for 2020 allocated to the Distribution Business were $28 million (2019 - $33 million). The estimated annual Pension Plan employer contributions allocated to the Distribution Business for the years 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $32 million, $49 million, $59 million, $60 million, $61 million, $62 million and $64 million respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the 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, 2020, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,763 million (2019 - $8,973 million). The fair value of pension plan assets available for these benefits was $8,103 million (2019 - $7,848 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2020, the Distribution Business charged $46 million (2019 - $31 million) of post-retirement and post-employment benefit costs to operation, maintenance and administration expenses, and capitalized $57 million (2019 - $34 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2020 were $24 million (2019 - $26 million). In addition, the associated post-retirement and post-employment benefits regulatory asset decreased by $25 million (2019 - increased by $130 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	2020	2019
Accrued liabilities	31	30
Post-retirement and post-employment benefit liability	1,000	947
Net unfunded status	1,031	977

Transfers from Other Plans

Effective March 1, 2018, certain employees who provided customer service operations for Hydro One through Inergi LP were transferred to Hydro One Networks' Distribution Business (Transferred Employees), and began accruing pension and OPEB in the Pension Plan and post-retirement and post-employment benefit plans, respectively. Pursuant to the arrangement, Inergi LP, Vertex Customer Management (Canada) Ltd. (Vertex) and Hydro One Networks agreed to transfer the defined benefit assets and related pension obligations (for current and former members) of the Inergi LP Customer Service Operations Pension Plan and the Vertex Customer Management (Canada) Limited Pension Plan to the Pension Plan. In addition, Inergi LP, Vertex and Hydro One Networks agreed to transfer the OPEB liability related to the Transferred Employees to Hydro One's post-retirement and post-employment benefit plans. Regulatory approval for the pension transfer was received on November 27, 2019.

The transfer of the OPEB liability of $33 million was completed on April 1, 2020. The liability was recorded as a post-retirement and post-employment benefit liability with an offset to OCL. In addition, as a part of the transfers, cash totaling $24 million was transferred to Hydro One Networks and recorded as an asset with an offset to OCI. Both, the OCI resulting from the transfer of the cash asset and the OCL resulting from the transfer of the other post-retirement benefit liability are being recognized in net income over the expected average remaining service lifetime (EARSL) of the Transferred Employees.

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	33	12	45
Interest accretion	1	—	1
Expenditures	(10)	(4)	(14)
Revaluation adjustment	4	3	7
Environmental liabilities - ending	28	11	39
Less: current portion	(10)	(4)	(14)
	18	7	25

Year ended December 31, 2019 *(millions of dollars)*	PCB	LAR	Total
Environmental liabilities - beginning	45	16	61
Interest accretion	1	—	1
Expenditures	(12)	(3)	(15)
Revaluation adjustment	(1)	(1)	(2)
Environmental liabilities - ending	33	12	45
Less: current portion	(8)	(6)	(14)
	25	6	31

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:

As at December 31, 2020 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	29	11	40
Less: discounting environmental liabilities to present value	(1)	—	(1)
Discounted environmental liabilities	28	11	39

As at December 31, 2019 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	36	13	49
Less: discounting environmental liabilities to present value	(3)	(1)	(4)
Discounted environmental liabilities	33	12	45

At December 31, 2020, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2021	14
2022	13
2023	5
2024	5
2025	2
Thereafter	1
	40

The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution 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 Distribution Business' 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.

At December 31, 2020, the Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations was $29 million (2019 - $36 million). These expenditures are expected to be incurred over the period from 2021 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2020 to increase the PCB environmental liability by $4 million (2019 - decrease by $1 million).

LAR

At December 31, 2020, the Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program was $11 million (2019 - $12 million). These expenditures are expected to be incurred over the period from 2021 to 2027. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2020 to increase the LAR environmental liability by $3 million (2019 - decrease by $1 million).

19. 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 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution 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. As a result of its annual review of asset retirement obligations, the Distribution Business recorded a revaluation adjustment in 2020 to increase the assets retirement liability by $1 million (2019 - $nil).

At December 31, 2020, Hydro One Networks had recorded asset retirement obligations of $6 million (2019 - $5 million) related to the Distribution 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.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and seven years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. 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. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Distribution Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2020**	**2019**
Lease expense	6	4
Lease payments made	5	3

As at December 31	**2020**	**2019**
Weighted-average remaining lease term[1] *(years)*	7	8
Weighted-average discount rate	2.6 %	2.7 %

[1] Includes renewal options that are reasonably certain to be exercised.

At December 31, 2020, future minimum operating lease payments were as follows:

(millions of dollars)	
2021	6
2022	6
2023	5
2024	5
2025	5
Thereafter	13
Total undiscounted minimum lease payments	40
Less: discounting minimum lease payments to present value	(4)
Total discounted minimum lease payments	36

At December 31, 2019, future minimum operating lease payments were as follows:

(millions of dollars)	
2020	5
2021	6
2022	5
2023	5
2024	5
Thereafter	16
Total undiscounted minimum lease payments[1]	42
Less: discounting minimum lease payments to present value	(5)
Total discounted minimum lease payments	37

[1] Excludes committed amounts of $3 million for leases that have not yet commenced.

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2020**	**2019**
Right-of-Use assets	34	36
Accounts payable and other current liabilities *(Note 12)*	5	4
Other long-term liabilities *(Note 13)*	32	33

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2020 and 2019, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2020, Hydro One Networks declared common share dividends in the amount of $1 million (2019 - $1 million) and made a return of stated capital of $607 million (2019 - $738 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends and return of stated capital was $274 million (2019 - $496 million).

22. 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 Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (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 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 Initial Public Offering (IPO). 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, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution 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 Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 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 2020, 218,368 common shares of Hydro One Limited were issued under the Share Grant Plans (2019 - 228,916) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2020 was $4 million (2019 - $4 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during the years ended December 31, 2020 and 2019 is presented below:

Year ended December 31, 2020	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,019,966	$20.50
Vested and issued[1]	(227,462)	—
Transfers to Hydro One Remote Communities[2]	(1,518)	$20.50
Transfers to Transmission Business[3]	(126,429)	$20.50
Forfeited	(40,454)	$20.50
Share grants outstanding - ending	1,624,103	$20.50

[1] In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] These transfers relate to share grants allocated to the Transmission Business for PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

[3] These transfers relate to share grants allocations between Hydro One Networks' Transmission and Distribution Businesses.

Year ended December 31, 2019	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,295,874	$20.50
Vested and issued[1]	(228,916)	—
Forfeited	(46,992)	$20.50
Share grants outstanding - ending	2,019,966	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

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 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 Board of Directors.

During 2020 and 2019, Directors' DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2020	2019
DSUs outstanding - beginning	42,688	41,107
Granted	5,975	7,993
Settled	(31,958)	(6,412)
DSUs outstanding - ending	16,705	42,688

For the years ended December 31, 2020 and 2019, the expense related to the Directors' DSU Plan was less than $1 million. At December 31, 2020 and 2019, the liability related to Directors' DSUs was less than $1 million.

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 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 Board of Directors.

During 2020 and 2019, Management DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	**2020**	**2019**
DSUs outstanding - beginning	13,485	33,902
Granted	2,354	5,308
Paid	(5,095)	—
Other [1]	—	(25,725)
DSUs outstanding - ending	10,744	13,485

[1] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended December 31, 2020, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

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 2020, Company contributions made under the ESOP and allocated to the Distribution Business were $1 million (2019 - $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 which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. 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 Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, 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.

<u>PSUs and RSUs</u>

During 2020 and 2019, LTIP awards granted by Hydro One Limited that related to the Distribution Business were as follows:

	PSUs		**RSUs**	
Year ended December 31 *(number of units)*	**2020**	**2019**	**2020**	**2019**
Units outstanding – beginning	41,750	232,132	36,692	156,215
Vested and issued [1]	(9,698)	(10,837)	(1,601)	(21,717)
Forfeited	(2,408)	(4,750)	(2,374)	(4,075)
Other [2]	—	(174,795)	—	(93,731)
Units outstanding – ending	29,644	41,750	32,717	36,692

[1] In 2020 and 2019, Hydro One Limited issued from treasury common shares to eligible Distribution Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the year ended December 31, 2020, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

No awards were granted in 2020 or 2019. The compensation expense related to the PSU and RSU awards recognized by the Distribution Business during 2020 and 2019 was not significant. At December 31, 2020 and 2019, the payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant.

23. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2020. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. Hydro One Telecom Inc. (Hydro One Telecom) is a subsidiary of Hydro One Limited. The following is a summary of the Distribution Business' related party transactions during the years ended December 31, 2020 and 2019:

Year ended December 31 *(millions of dollars)* Related Party	Transaction	2020	2019
IESO	Power purchased	2,454	1,808
	Amounts related to electricity rebates	1,581	689
	Distribution revenues related to rural rate protection	242	240
	Funding received related to Conservation and Demand Management programs	24	42
OPG	Power purchased	6	8
	Revenues related to supply of electricity	6	6
	Costs related to the purchase of services	1	—
OEFC	Power purchased from power contracts administered by the OEFC	1	2
OEB	OEB fees	5	5
Hydro One	Payments to finance dividends and return of stated capital	274	496
	Interest expense on long-term debt	185	181
	Stock-based compensation costs	5	5
	Interest expense on inter-company demand facility	2	6
	Services received - costs expensed	1	2
Hydro One Networks' Transmission Business	Services received - costs expensed	2	3
	Capital contributions received	3	6
Hydro One Telecom	Services received - costs expensed	5	6
Hydro One Limited and its other subsidiaries	Revenues for services provided	7	4
	Services received - costs recovered	3	1

The amounts due to and from related parties at December 31, 2020 and 2019 are as follows:

As at December 31 *(millions of dollars)*	2020	2019
Inter-company demand facility	107	(303)
Due from related parties	183	278
Due to related parties	(321)	(302)
Accrued interest	(45)	(42)
Long-term inter-company payable	(17)	(15)
Long-term debt, including current portion	(4,750)	(4,235)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2020	2019
Accounts receivable	6	(32)
Due from related parties	95	(153)
Other assets	(4)	(5)
Accounts payable	9	11
Accrued liabilities	(110)	63
Due to related parties	19	218
Accrued interest	3	4
Long-term accounts payable and other liabilities	—	1
Post-retirement and post-employment benefit liability	24	19
	42	126

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2020 and 2019. The reconciling items include net change in accruals and capitalized depreciation.

Year ended December 31, 2020 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(634)	(73)	(707)
Reconciling items	20	3	23
Cash outflow for capital expenditures	(614)	(70)	(684)

Year ended December 31, 2019 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(560)	(60)	(620)
Reconciling items	20	1	21
Cash outflow for capital expenditures	(540)	(59)	(599)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2020	2019
Net interest paid	182	177
Income taxes paid	21	17

25. 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 Distribution Business' financial position, results of operations or cash flows.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

26. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

27. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 23, 2021, Hydro One Networks declared a dividend of $149 million. The amount allocated to the Distribution Business to finance this payment was $68 million.

Deferred Tax Asset Sharing

On April 8, 2021, the OEB rendered the Implementation Decision. In its decision, the OEB approved recovery of the deferred tax asset amounts allocated to ratepayers for the 2018 to 2021 period plus carrying charges over a two-year period commencing on July 1, 2021. In addition, Hydro One shall adjust the base distribution rates beginning January 1, 2022 to eliminate any further amounts of future tax savings flowing to customers. The impact of the Implementation Decision will be reflected prospectively in the Distribution Business' financial statements.

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 S&P Global Ratings.

- Attachment 1: Moody's Investor Service, Credit Opinion, dated: December 21, 2020
- Attachment 2: S&P Global Ratings Research, dated: March 11, 2021
- Attachment 3: DBRS Report, dated: April 21, 2021

This page left blank intentionally.

Filed: 2021-08-05
EB-2021-0110
Exhibit A-6-3
Attachment 1
Page 1 of 10

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
21 December 2020

Update

Rate this Research

RATINGS

Hydro One Inc.

Domicile	Toronto, Ontario, Canada
Long Term Rating	A3
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.

Contacts

Gavin MacFarlane +1.416.214.3864
VP-Sr Credit Officer
gavin.macfarlane@moodys.com

Natividad Martel, CFA +1.212.553.4561
VP-Senior Analyst
natividad.martel@moodys.com

Gajendra Mandal +1.416.214.3861
Associate Analyst
gajendra.mandal@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Hydro One Inc.

Update to credit analysis

Summary

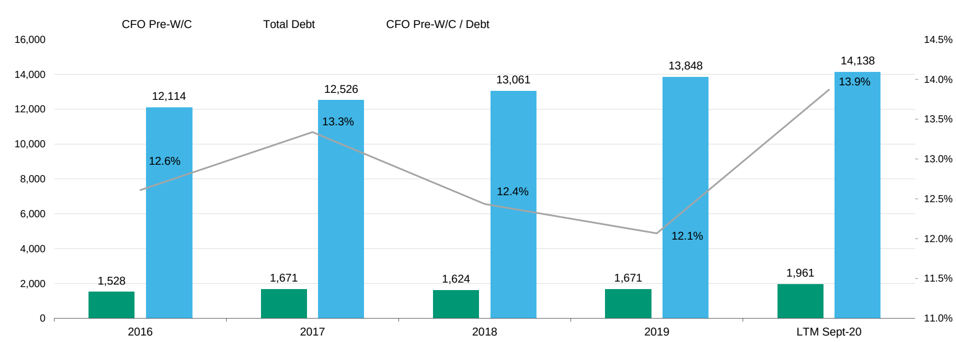
Hydro One Inc.'s (HOI) credit profile reflects its baseline credit assessment (BCA) of baa1 with a one notch uplift attributable to the moderate probability of extraordinary support from the Province of Ontario (Aa3 stable), which indirectly owns 47.3% of HOI. HOI's credit quality is analyzed under our Regulated Electric and Gas Utilities rating methodology, and reflects the regulated nature of its operations and its low business risk profile. The utility's rate base consists of roughly 61% transmission and 39% distribution, and it benefits from a credit supportive regulatory environment under the Ontario Energy Board (OEB).

We expect cash flow from operations to be predictable but financial metrics to remain weak. HOI's relatively low financial metrics are primarily the result of its existing allowed return on equity (currently set at 8.52% for transmission and 9% for distribution) and authorized equity layer in the capital structure (currently 40%) that are established by the OEB, as well as low depreciation rates that are a function of long-life T&D assets.

Recent Developments

The rapid spread of the coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework given the substantial implications for public health and safety. However, we expect HOI will be relatively resilient to recessionary pressures because of its rate regulated business model and supportive regulatory mechanisms.

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

» Moderate probability of extraordinary support from the Province

Credit challenges

» High leverage

» Incentive rate regulation marginally increases risk

Rating outlook

The stable outlook reflects the company's renewed focus on the credit supportive Ontario regulatory jurisdiction and our expectation of weak but consistent financial metrics including CFO pre-W/C to debt in the 11-13% range.

Factors that could lead to an upgrade

» Key financial metrics increase, including CFO/debt forecast to be sustained above 14%

» An improvement in regulatory outcomes

» A strengthening of the relationship with the Province

Factors that could lead to a downgrade

» Key financial metrics decline, including CFO/debt forecast to be sustained below 11%

» A deterioration in regulatory outcomes

» A lower probability of extraordinary support from the Province

Key indicators

Exhibit 2

Hydro One Inc.

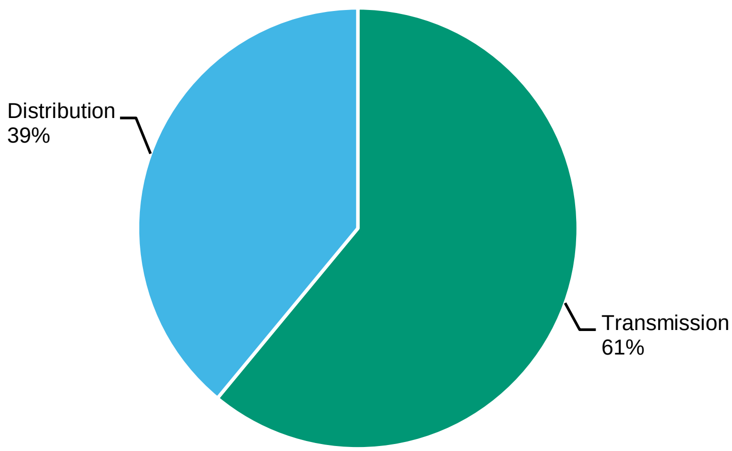
	Dec-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
CFO Pre-W/C + Interest / Interest	4.3x	4.4x	4.2x	4.2x	4.6x
CFO Pre-W/C / Debt	12.6%	13.3%	12.4%	12.1%	13.9%
CFO Pre-W/C – Dividends / Debt	7.5%	8.9%	8.2%	6.6%	9.8%
Debt / Capitalization	55.0%	55.4%	57.9%	58.8%	56.7%

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 47.3% indirectly owned by the Province of Ontario. Hydro One Limited (HOL unrated) is the publicly traded vehicle that owns 100% of HOI. In recent years, HOI has had its rates set by the OEB under cost of service and inflation based frameworks. Currently both segments have rates set using incentive rate frameworks. The transmission business owns and operates virtually all of Ontario's electricity transmission system representing 54% of HOI's total assets of CAD28.4 billion as of 30 September 2020. The distribution business serves about 1.4 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 $20.7 billion 2019 rate base by segment



Source: HOL's presentation

Detailed credit considerations

Supportive regulatory environment

The supportive Ontario regulatory environment is a key driver of HOI's credit quality. 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, with legislative and judicial underpinnings that are well developed and we expect them to remain unchanged. 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 low 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.

The year 2020 was the first in which both transmission and distribution rates have been established based on an incentive rate mechanisms. In March 2019, the company received a custom incentive rate decision for the distribution business for the period 2018-2022. Prior to that decision, rates had been set under a 3 year incentive rate model. Rates for the transmission business are being set using custom incentive rate regulation for the first time. In April 2020, an OEB decision established rates under an incentive rate making model for the period 2020-2022. Rates for the transmission business for 2019 were established using inflation based principles, where inflation rates are a key driver of rate setting and the OEB set the revenue index at 1.4% for 2019. Prior to 2019 rates for the transmission business were established using cost of service principles with frequent rate resets. We expect HOI to file a joint transmission and distribution rate application for the period 2023-2027 in 2021. While we have noted some lag in the timeliness of decisions, this has been somewhat mitigated by interim rates that are generally established at levels requested by the company.

Incentive rate regulation marginally increases risk compared to a cost of service regulatory model because of the potential for higher cash flow volatility over time, particularly towards the end of a longer duration period between rate cases. Annual revenue growth is driven by an inflation factor, a productivity factor and a capital factor. This is a custom incentive rate framework because both the productivity factor and capital factor contain elements specific to the company. This provides predictability in rate setting and HOI revenues through 2022.

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 established by the regulator, the allowed return on equity currently set at 8.52% for transmission and 9% for distribution, and depreciation. We have assumed that the company continues to perform broadly in line with the levels established by the regulator and forecast CFO pre-W/C to debt in the 11-13% range.

Exhibit 4
Summary of key regulatory elements

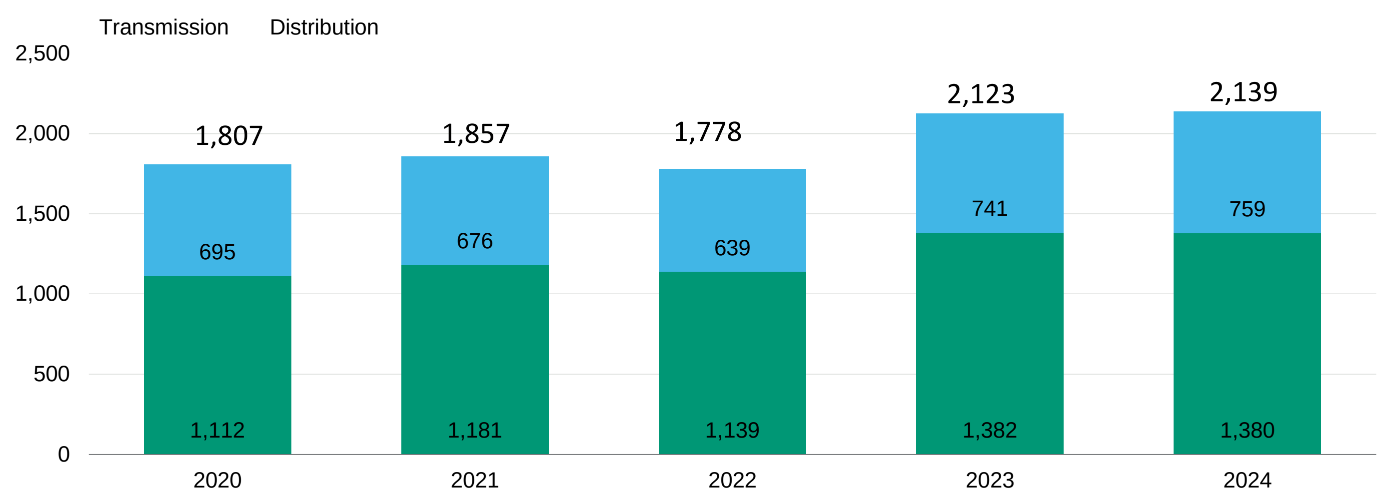
Segment	2020 Rate base, CAD million	Equity Thickness	Allowed ROE	Regulatory Update
Transmission	12,360	40%	8.5%	April 2020 decision for 2020-2022
Distribution	8,175	40%	9.0%	March 2019 decision for 2018-2022

Source: Company filings

HOI continues to move forward with a large capital program of about CAD9.5 billion over the period 2020-2024 with about CAD6 billion of investment in transmission and about CAD3.5 billion in the distribution business. Both business segments benefit from a capital factor rate adjustment that provides cash flow support to the capital program between rate cases. In the absence of the capital factor, financial metrics would be much weaker as capital expenditures are more than double annual depreciation. 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.

On July 16, 2020, the company received a favorable decision from the Ontario Divisional Court resolving an ongoing dispute relating to sharing a tax asset with customers that stemmed from the company's IPO in 2015. This led to an income tax recovery in the first 9 months of 2020 of CAD812 compared to an income tax expense of CAD48 million in the first 9 months of 2019. The annual impact on cash flow is likely in the CAD50-60 million range. However, since the 2017 OEB decision, some benefits have previously been shared with customers that HOI may recover and this may have a modestly larger cash flow impact in the next few years.

Exhibit 5
Projected capital expenses by segment
(CAD million)



Source: Company filings

Relationship with and support from the Province of Ontario

HOI completed a strategic review in Q4 2019 and determined that it will remain focused exclusively on its businesses in Ontario for at least the next 5 years. A key outcome of the strategic review is that Hydro One and its parent Hydro One Limited (unrated) will have a long-term focus on doing business in the Province of Ontario, which is a key consideration in our determination that Hydro One is a Government Related Issuer (GRI).

In accordance with Moody's GRI methodology, HOI's A3 rating reflects the following:

» Aa3/stable local currency rating of the Province of Ontario.

» Very high default dependence as a result of HOI and the Province deriving the vast majority of their revenues from within the government's territory and sharing some political risks.

» Moderate probability of extraordinary support from the Province reflecting the strategic importance of HOI to the provincial economy as an essential service provider and the current 47.3% indirect ownership interest that the Province has in HOI.

We believe the Province will continue to have effective control over HOI. For example, the Province exercised this control when it removed the board and CEO of HOI and HOL in July of 2018. Following HOL's partial privatization in 2015, although the Province reduced its stake to 47.3%, it is required by legislation to maintain a 40% equity interest in HOL. In addition, limitations have been placed on other shareholders that restrict their equity interest in HOL to less than 10%. HOI is restricted from selling a large portion of its regulated transmission or distribution business and will continue to be regulated by the Ontario Energy Board (OEB).

Mitigating its control somewhat, the government has implemented a predefined set of criteria to promote an independent, professional board with relevant expertise and a commercial orientation. These changes have been made in a stated attempt to improve the efficiency of HOI and they also reduce the government ties to the company. HOL has CAD425 million of term debt outstanding and its own CAD250 million committed credit facility that is typically undrawn and expires in June 2024. HOL's credit profile does not constrain the credit profile of HOI.

ESG considerations

As an electric transmission and distribution utility, HOI has low carbon transition risk. The company benefits from favorable billing practices whereby customers are charged a fixed rate for T&D costs and a separate volumetric charge for volumes consumed. The company is exposed to moderate social risks that primarily relate to health and safety. The company's strategic review completed in November 2019 lists its strategic priorities as efficiency and safety and building on existing relationships with indigenous communities and partners. The company has relatively complex governance owing to the government's ownership and intervention while at the same time positioning itself as an arm's length investor.

Liquidity analysis

HOI has an adequate liquidity profile as demonstrated by its sources of capital exceeding its uses over the next 12 months. In addition, we believe that the company continues to have strong access to the debt capital markets.

HOI's sources of capital include estimated operating cash flow of around CAD1.8-2.0 billion over the next 12 months and CAD2.3 billion of bank syndicated committed facilities that expire in June of 2024 that backstop its commercial paper program which had CAD985 million outstanding at September 30, 2020. We also include debt issuances of CAD1.2 billion of long term debt issued on October 9, 2020, just after quarter end as a source of liquidity in our analysis. These sources are more than sufficient to cover capex of around CAD1.9 billion, dividends of about CAD700 million and CAD800 million of debt maturities.

HOI and HOL have a single financial covenant requiring that they maintain a debt to capitalization ratio of no more than 75%. As of September 30, 2020, both companies were in compliance.

Rating methodology and scorecard factors

Exhibit 6

Rating Factors

Hydro One Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 9/30/2020		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)	4.4x	Baa	4x - 4.5x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	12.8%	Baa	11% - 13%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	8.1%	Baa	7% - 9%	Baa
d) Debt / Capitalization (3 Year Avg)	57.0%	Baa	55% - 60%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Government-Related Issuer	**Factor**
a) Baseline Credit Assessment	baa1
b) Government Local Currency Rating	Aa3
c) Default Dependence	Very High
d) Support	Moderate
e) Actual Rating Assigned	A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2020(L)
[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

	Hydro One Inc. A3 (Stable)			FortisBC Inc. Baa1 (Stable)			Newfoundland Power Inc. Baa1 (Stable)			FortisAlberta Inc. Baa1 (Stable)		
(In CAD millions)	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-19	FYE Dec-19	LTM Sept-20
Revenue	6,110	6,442	7,098	391	404	407	664	684	710	623	650	662
CFO Pre-W/C	1,624	1,671	1,961	114	108	107	117	111	125	315	353	341
Total Debt	13,061	13,848	14,138	1,160	1,233	1,218	629	638	677	2,251	2,279	2,446
CFO Pre-W/C + Interest / Interest	4.2x	4.2x	4.6x	3.6x	2.5x	2.5x	4.2x	4.0x	4.4x	4.1x	4.4x	4.3x
CFO Pre-W/C / Debt	12.4%	12.1%	13.9%	9.8%	8.8%	8.8%	18.7%	17.4%	18.5%	14.0%	15.5%	13.9%
CFO Pre-W/C – Dividends / Debt	8.2%	6.6%	9.8%	6.1%	5.1%	5.2%	14.3%	13.0%	14.3%	10.9%	12.2%	10.7%
Debt / Capitalization	57.9%	58.8%	56.7%	55.1%	56.0%	54.0%	48.8%	48.1%	49.4%	56.2%	55.8%	56.7%

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-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
As Adjusted					
FFO	**1,455**	**1,584**	**1,600**	**1,651**	**1,896**
+/- Other	73	87	24	20	65
CFO Pre-WC	**1,528**	**1,671**	**1,624**	**1,671**	**1,961**
+/- ΔWC	95	-24	-74	7	116
WC	1,623	1,647	1,550	1,678	2,077
WC	1,528	1,671	1,624	1,671	1,961
CFO	**1,623**	**1,647**	**1,550**	**1,678**	**2,077**
- Div	620	556	558	760	576
- Capex	1,610	1,489	1,486	1,584	1,780
FCF	**-607**	**-398**	**-494**	**-666**	**-279**
(CFO Pre-W/C) / Debt	12.6%	13.3%	12.4%	12.1%	13.9%
(CFO Pre-W/C - Dividends) / Debt	7.5%	8.9%	8.2%	6.6%	9.8%
FFO / Debt	12.0%	12.6%	12.3%	11.9%	13.4%
RCF / Debt	6.9%	8.2%	8.0%	6.4%	9.3%
Revenue	6,502	5,947	6,110	6,442	7,098
Interest Expense	464	487	507	522	538
Net Income	636	587	-234	814	1,723
Total Assets	25,296	25,598	25,556	26,869	28,414
Total Liabilities	15,498	15,639	16,183	17,294	17,698
Total Equity	9,798	9,959	9,373	9,575	10,716

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 9

Hydro One Inc. Moody's - Adjusted Debt Breakdown

(CAN Millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-19	LTM Sept-20
As Reported Debt	**10,198.0**	**11,149.0**	**10,996.0**	**11,961.0**	**12,618.0**	**12,907.0**
Pensions	952.0	900.0	981.0	547.0	1,125.0	1,125.0
Operating Leases	34.4	40.0	40.0	40.0	74.0	72.0
Hybrid Securities	0.0	0.0	486.0	486.0	0.0	0.0
Non-Standard Adjustments	0.0	25.0	23.0	27.0	31.0	34.0
Moody's Ajusted Debt	**11,184.4**	**12,114.0**	**12,526.0**	**13,061.0**	**13,848.0**	**14,138.0**

Based on consolidated financial data of Hydro One Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics

Exhibit 10

Hydro One Inc. Moody's - Adjusted EBITDA Breakdown

(CAN Millions)	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-19	LTM Sept-20
As Reported EBITDA	**1,850.0**	**1,929.0**	**1,957.0**	**2,056.0**	**2,228.0**	**2,265.0**
Pensions	17.0	-28.0	-59.0	-101.0	-104.0	-77.0
Operating Leases	6.0	10.0	10.0	10.0	9.0	13.0
Moody's Adjusted EBITDA	**1,873.0**	**1,911.0**	**1,908.0**	**1,965.0**	**2,133.0**	**2,201.0**

Based on consolidated financial data of Hydro One Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
HYDRO ONE INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper -Dom Curr	P-2

Source: Moody's Investors Service

REPORT NUMBER 1255912

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

S&P Global
Ratings

Research

Hydro One Inc.

Primary Credit Analyst:
Mayur Deval, Toronto (1) 416-507-3271; mayur.deval@spglobal.com

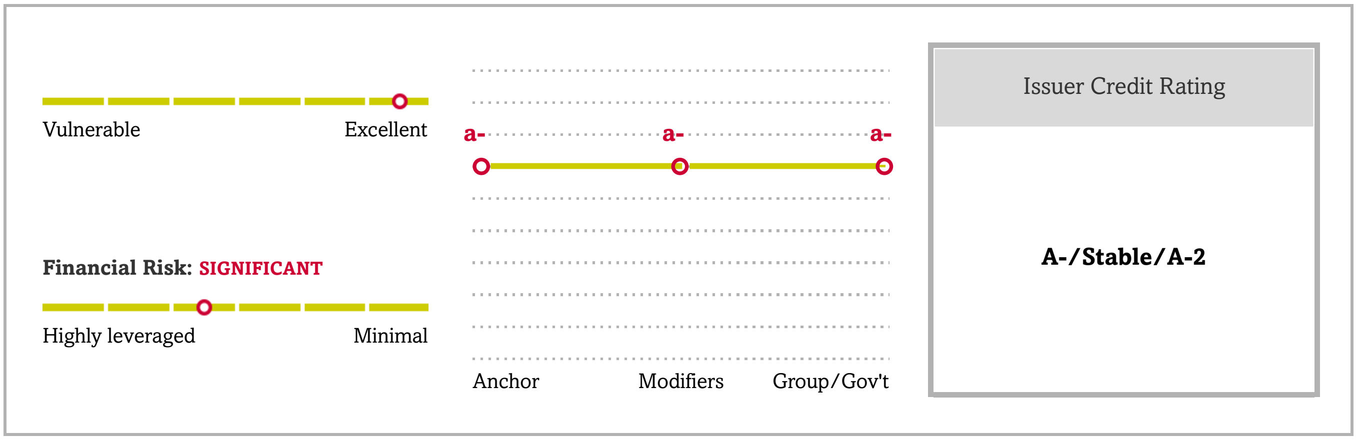
Secondary Contact:
Andrew Ng, Toronto + 1 (416) 507 2545; andrew.ng@spglobal.com

Research Contributor:
Jesal Gandhi, CRISIL Global Analytical Center, an S&P Global Ratings affiliate, Mumbai

Table Of Contents

Table Of Contents (cont.)

Hydro One Inc.



Credit Highlights

Overview	
Key strengths	**Key risks**
A relatively strong regulatory structure that supports stable cash flows for the low-risk electricity transmission and distribution (T&D) business	Elevated capital spending to replace aging infrastructure over the next several years could lead to weaker financial measures.
Company operates in Ontario only but has a large footprint across the province.	Low likelihood of extraordinary government support.
No exposure to commodity costs.	

The Ontario Energy Board (OEB) established deferral accounts to record costs and losses arising from the COVID-19 pandemic. The OEB, Ontario's regulator, acknowledged that utility distributors, including those of Hydro One Inc. (HOI), may incur incremental costs related to the ongoing COVID-19 pandemic. As a result, the OEB established deferral accounts for utilities to track incremental costs and lost revenues related to the COVID-19 pandemic. This provides HOI the authority to recover potential lost revenue, incremental expenses, or costs relating to bad debt expenses subject to OEB approval. We expect rate recovery of deferred costs will partly mitigate lost revenues and cash flow volatility due to the pandemic.

HOI is a fully regulated utility with a large footprint across Ontario. HOI is a fully regulated electric transmission and distribution (T&D) intermediate holding company of utilities. Although the utility operates only in Ontario, it owns 98% of the province's transmission capacity, serves about 1.4 million distribution customers through its distribution operations , and covers approximately 75% of the region.

HOI has an elevated capital-spending plan over the outlook period. HOI continues its elevated capital spending through 2023, averaging about C$2 billion per year. This is a little more than twice the company's annual depreciation expense, which will pressure credit metrics and can lead to higher execution risks such as completing key projects on time and within budget.

HOI's operating environment has stabilized but the risk of government intervention still exists. HOI's operating environment has stabilized with the ongoing reform of the OEB that promotes transparency, regulatory independence, and efficiency. With these reforms, we believe that the government currently is unlikely to intervene again with Hydro One Ltd. (HOL), the parent of HOI. However, the risk of government intervention still exists given the government still has the authority to exercise legislative power to override HOL's board decisions. Over the past few years, we have witnessed improved governance with no political intervention.

Outlook: Stable

The stable outlook on HOI reflects that of the outlook on parent company HOL. We expect HOL will continue to focus on regulated operations in Ontario and we do not expect the utility to expand outside of Ontario. During our two-year outlook period, we expect HOL's funds from operations (FFO) to debt to range between 10.7%-11.7%.

Downside scenario

We could take a negative rating action on HOI over the next 18 to 24 months if we downgrade the parent holding company HOL. This could happen if HOL's financial measures deteriorate such that FFO to debt consistently remains below 11% with no prospect for improvement.

Alternatively, we could lower the ratings if HOL decides to pursue growth outside of Ontario or in other business opportunities that have higher business risks or if the Ontario government intervenes further in HOL's business or operating decisions, resulting in additional governance deficiencies that we consider severe.

Upside scenario

Although unlikely, we could raise the ratings on HOL and HOI over the next 18 to 24 months if the utility improves its financial measures, including FFO to debt consistently above 16%.

Our Base-Case Scenario

Assumptions

- HOL and HOI will continue to focus on regulated electricity T&D businesses in Ontario.
- HOI will not experience material adverse regulatory decisions from the OEB which will continue to operate in a predictable and transparent manner.
- HOI will continue to earn close to its allowed return on equity based on the authorized capital structure.
- Capital expenditures averaging about C$2 billion per year from 2021-2023.
- Dividend payments averaging about C$690 million per year from 2021-2023.
- We did not factor in the pending deferred tax decision in the base case scenario.

Key Metrics

Hydro One Inc.--Key Metrics

	2021f	2022f	2023f
FFO to debt (%)	11.2-11.6	11.5-11.9	11.7-12.1
FFO to cash interest (x)	3.9-4.3	3.9-4.3	3.9-4.3

Hydro One Inc.--Key Metrics (cont.)			
	2021f	**2022f**	**2023f**
Debt to EBITDA (x)	6.2-6.8	6.1-6.7	6-6.6

f--forcast. FFO--Funds from operations.

Company Description

HOI is an intermediate holding company of HOL, and owns operating electricity transmission and distribution utilities in Ontario. HOI, through its operating subsidiary Hydro One Networks Inc., owns and operates virtually all of Ontario's electricity transmission network, and approximately 124,000 circuit kilometers of primary low-voltage distribution lines. HOI's utilities deliver electricity to approximately 1.4 million residential customers, as well as to industrial customers and municipal utilities, in the province.

Peer Comparison

Table 1

Hydro One Inc.--Peer Comparison

Industry Sector: Electric

	Hydro One Inc.	**Toronto Hydro Corp.**	**CU Inc.**	**AltaLink L.P.**	**ITC Holdings Corp.**
Ratings as of March 5, 2021	A-/Stable/A-2	A/Stable/--	A-/Stable/A-2	A/Stable/--	A-/Negative/A-2
	--Fiscal year ended Dec. 31, 2019--				
(Mil. Mix curr.)	C$	C$	C$	C$	$
Revenue	6,442.0	3,673.3	2,787.0	932.2	1,327.0
EBITDA	2,316.0	584.8	1,557.0	721.9	999.0
Funds from operations (FFO)	1,807.0	461.8	1,178.5	527.4	765.8
Interest expense	503.0	96.6	389.7	194.2	232.2
Cash interest paid	488.0	85.7	384.5	194.5	236.2
Cash flow from operations	1,678.0	507.7	1,155.5	698.0	621.8
Capital expenditure	1,577.0	568.1	936.0	315.6	857.0
Free operating cash flow (FOCF)	101.0	(60.4)	219.5	382.4	(235.2)
Discretionary cash flow (DCF)	(1,145.0)	(160.8)	(171)	92.0	(485.2)
Cash and short-term investments	7.0	0.0	71.0	1.3	7.0
Debt	14,920.1	2,567.3	8,371.4	4,927.6	5,862.5
Equity	9,723.0	1,887.5	4,853.0	3,350.9	2,232.0
Adjusted ratios					
EBITDA margin (%)	36.0	15.9	55.9	77.4	75.3
Return on capital (%)	6.0	7.7	8.3	5.4	10.1
EBITDA interest coverage (x)	4.6	6.1	4.0	3.7	4.3
FFO cash interest coverage (x)	4.7	6.4	4.1	3.7	4.2
Debt/EBITDA (x)	6.4	4.4	5.4	6.8	5.9
FFO/debt (%)	12.1	18.0	14.1	10.7	13.1

Table 1

Hydro One Inc.--Peer Comparison (cont.)

Industry Sector: Electric

	Hydro One Inc.	Toronto Hydro Corp.	CU Inc.	AltaLink L.P.	ITC Holdings Corp.
Cash flow from operations/debt (%)	11.2	19.8	13.8	14.2	10.6
FOCF/debt (%)	0.7	(2.4)	2.6	7.8	(4.0)
DCF/debt (%)	(7.7)	(6.3)	(2.0)	1.9	(8.3)

Source: S&P Global Ratings and company data.

Business Risk: Excellent

Our assessment of HOI's business risk profile largely reflects its low-risk electricity T&D operations and our view of its management of regulatory risk.

The utility continues to operate under a supportive regulatory environment. The OEB is the provincial regulator and provides a generally transparent, consistent, and independently operated regulatory framework that supports a stable and predictable cash flow model. We view this as a key credit strength. In addition, local distribution companies in Ontario, including HOI, do not have power procurement obligations, reducing operating risk. Furthermore, HOI has limited exposure to commodity risk since the Independent Electricity System Operator (IESO) procures power and distribution companies (acting as billing agents) collect these costs from ratepayers.

Further supporting the business risk profile is HOI's monopoly position in its service territories and the asset-intensive nature of its electric T&D operations, both of which limit risk from competition. Additionally, HOI has a large footprint in Ontario (owning 98% of transmission capacity and serves about 1.4 million customers through its distribution utilities). We believe the company's customer base supports the overall stability of revenues and greatly limits exposure to any particular customer segment. In the transmission business, municipally owned investment-grade electricity local distribution companies collect transmission revenues and forward them to HOI through the IESO. The company's distribution business collects revenues from a relatively stable base of residential and commercial customers. We view the economy of Ontario, which the transmission business services, as large, wealthy, and well diversified. We do not expect the utility's customer composition to change materially over the next two years.

Financial Risk: Significant

Under our base-case scenario, which includes capital spending averaging about C$2 billion per year and dividend payments averaging about C$690 million per year from 2021-2023, we expect HOI's adjusted FFO to debt of about 11.3%-12% during this period. Our base-case scenario excludes the potential impact from the Ontario Divisional Court's (ODC) order on the deferred tax asset decision. The ODC has ordered HOI to submit its proposal for the recovery of the deferred tax asset. Once implemented, this has a potential upside to the HOI's cash flows. We expect HOI's discretionary cash flow will remain negative and will require external funding, including debt. We also anticipate minimal EBITDA growth and adjusted debt to EBITDA to be elevated and above 6x over the next few years.

We base our assessment on our low-volatility financial benchmarks, which are the most relaxed when compared to those used for a typical corporate issuer. This reflects the company's focus on low-risk, regulated electric T&D operations and strong management of regulatory risk.

Financial summary

Table 2

Hydro One Inc. Financial Summary

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2019	2018	2017	2016	2015
(Mil. C$)					
Revenue	6,442.0	6,110.0	5,947.0	6,502.0	6,529.0
EBITDA	2,316.0	2,140.0	2,099.5	2,102.5	1,972.5
Funds from operations (FFO)	1,807.0	1,641.3	1,610.6	1,652.5	1,174.2
Interest expense	503.0	492.7	489.9	443.0	429.3
Cash interest paid	488.0	483.7	477.9	420.0	470.3
Cash flow from operations	1,678.0	1,533.3	1,621.6	1,621.5	(1,304.8)
Capital expenditure	1,577.0	1,478.0	1,480.0	1,601.0	1,480.0
Free operating cash flow (FOCF)	101.0	55.3	141.6	20.5	(2,784.8)
Discretionary cash flow (DCF)	(1,145.0)	(487.7)	(390.4)	(599.5)	(3,677.8)
Cash and short-term investments	7.0	492.0	0.0	48.0	89.0
Gross available cash	7.0	492.0	0.0	48.0	89.0
Debt	14,920.1	13,577.5	13,526.1	12,958.1	12,205.6
Equity	9,723.0	9,512.0	10,102.0	9,941.0	9,825.0
Adjusted ratios					
EBITDA margin (%)	36.0	35.0	35.3	32.3	30.2
Return on capital (%)	6.0	5.5	5.5	5.8	6.3
EBITDA interest coverage (x)	4.6	4.3	4.3	4.7	4.6
FFO cash interest coverage (x)	4.7	4.4	4.4	4.9	3.5
Debt/EBITDA (x)	6.4	6.3	6.4	6.2	6.2
FFO/debt (%)	12.1	12.1	11.9	12.8	9.6
Cash flow from operations/debt (%)	11.2	11.3	12.0	12.5	(10.7)
FOCF/debt (%)	0.7	0.4	1.0	0.2	(22.8)
DCF/debt (%)	(7.7)	(3.6)	(2.9)	(4.6)	(30.1)

N.M.--Not meaningful

Reconciliation

Table 3

Hydro One Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2019--							
Hydro One Inc. reported amounts (mil. C$)								
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	12,618.0	9,644.0	2,340.0	1,469.0	449.0	2,316.0	1,719.0	1,625.0
S&P Global Ratings' adjustments								
Cash taxes paid	--	--	--	--	--	(21.0)	--	--
Cash interest paid	--	--	--	--	--	(438.0)	--	--
Reported lease liabilities	74.0	--	--	--	--	--	--	--
Operating leases	--	--	9.0	2.0	2.0	(2.0)	7.0	--
Postretirement benefit obligations/deferred compensation	2,124.2	--	(37.0)	(37.0)	--	--	--	--
Accessible cash and liquid investments	(7.0)	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	48.0	(48.0)	(48.0)	(48.0)
Asset-retirement obligations	111.0	--	4.0	4.0	4.0	--	--	--
Nonoperating income (expense)	--	--	--	(11.0)	--	--	--	--
Noncontrolling interest/minority interest	--	79.0	--	--	--	--	--	--
Total adjustments	2,302.1	79.0	(24.0)	(42.0)	54.0	(509.0)	(41.0)	(48.0)
S&P Global Ratings' adjusted amounts								
	Debt	**Equity**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Capital expenditure**
	14,920.1	9,723.0	2,316.0	1,427.0	503.0	1,807.0	1,678.0	1,577.0

Source: S&P Global Ratings and company data.

Liquidity: Adequate

We assess HOI's stand-alone liquidity as adequate because we believe its sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. We believe HOI has sound banking relationships, the ability to absorb high-impact, low-probability events without refinancing, and a satisfactory standing in the credit markets. Update latest

Principal liquidity sources

- Estimated cash balance of about C$712 million;
- Credit facilities availability of about C$2.3 billion; and
- Estimated cash FFO of about C$1.9 billion.

Principal liquidity uses

- Debt maturities of about C$1.6 billion;
- Capital spending of about C$1.9 billion; and
- Dividends of about C$655 million.

Debt maturities

- 2021: $803 million
- 2022: $604 million
- 2023: $731 million
- 2024: $700 million
- 2025: 750 million

Environmental, Social, And Governance

Although we do not expect the Ontario government to further intervene with parent HOL and HOI, we believe their credit quality is more negatively influenced by its ownership and governance structure than peers, resulting in our assessment of their management and governance as fair only. Specifically, HOL is partly owned by the government of Ontario and the government could potentially exercise legislative power to promote its own interests and priorities above those of other stakeholders, as we have seen in the past. In 2018, the Ontario government passed an amendment to the Ontario Energy Board Act 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 government 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.

HOI's environmental and social risk is not materially different from that of regulated electric utility network peers.

Group Influence

Under our group rating methodology, we consider HOI a core subsidiary of HOL, reflecting our view that HOI is highly unlikely to be sold, is integral to the group's overall strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. We assess the issuer credit rating for HOI to be in line with the group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

- Our 'A-2' short-term rating on HOI is based on our long-term issuer credit rating.
- We also rate HOI's CP program at 'A-2' on the global scale or 'A-1 (Low)' on the Canadian National Scale based on our long-term issuer credit rating of HOI.

Capital structure

- HOI's capital structure includes roughly C$13.1 billion of debt including about C$13 billion of senior unsecured debt.

Analytical conclusions

- We rate HOI's senior unsecured debt at the same level as our long-term issuer credit rating because priority debt does not exceed 50% of the company's consolidated debt, after which point HOI's debt could be considered structurally subordinated.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/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-
- **Entity status within group:** Core (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- 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
- Criteria | Corporates | General: The Treatment Of Non-Common Equity Financing In Nonfinancial Corporate Entities, April 29, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of March 11, 2021)*

Hydro One Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Issuer Credit Ratings History	
08-Nov-2019	A-/Stable/A-2

Ratings Detail (As Of March 11, 2021)*(cont.)	
10-Dec-2018	A-/Negative/A-2
13-Sep-2018	A-/Watch Neg/A-2
15-Jun-2018	A/Watch Neg/A-1
19-Jul-2017	A/Negative/A-1

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Rating Report
Hydro One Inc.

DBRS Morningstar
April 21, 2021

Contents

Tom Li
+1 416 597-7378
tom.li@dbrsmorningstar.com

Ram Vadali, CFA, CPA
+1 416 597-7526
ram.vadali@dbrsmorningstar.com

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 14, 2021, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Debentures rating of Hydro One Inc. (HOI or the Company) at A (high) and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings are based on the stability of HOI's regulated transmission and distribution businesses which operate under reasonable regulation by the Ontario Energy Board (OEB).

HOI's business risk assessment has remained steady. In April 2020, the OEB approved the Company's first transmission Custom Incentive Rate-setting (IR) application for 2020 to 2022. Like the 2018 to 2022 distribution Custom IR decision, revenues were set using cost-of-service (COS) for the first year, then escalating annually by inflation, capital, productivity, and stretch factors for the remaining term. DBRS Morningstar notes the Custom IR decisions will provide further stability for HOI as well as certainty of funding for its large capital expenditures (capex) program (around $2 billion annually).

In July 2020, the Ontario Divisional Court set aside the OEB's decision on the treatment of HOI's deferred tax asset. The court found that the OEB's decision was incorrect in law that the deferred tax asset should be shared with ratepayers; the court agreed with the Company that it should be allocated entirely to shareholders. In April 2021, the OEB approved a refund of misallocated future tax savings of $257 million from ratepayers to shareholders over a two-year period beginning July 1, 2021. Additionally, DBRS Morningstar expects the deferred tax asset treatment to increase the Company's cash flows by $50 million to $60 million annually and lead to a modest improvement in its key credit metrics.

HOI's key credit metrics remained supportive of the A (high) rating, although the cash flow-to-debt ratio did weaken for the year because of the timing of a $1.2 billion notes issuance in October 2020. The Company was largely able to mitigate the impact from the Coronavirus Disease (COVID-19) pandemic through cost control and efficiency gains throughout the year. DBRS Morningstar will continue to monitor any impact the pandemic has on HOI's operations and financial results. DBRS Morningstar considers a positive rating action to be unlikely given the Company's key credit metrics and the current regulatory framework, as well as uncertainty with the ongoing coronavirus pandemic. A negative rating action may occur if HOI's key credit metrics weaken to a level no longer commensurate with the current rating category for a sustained period, such as if the cash flow-to-debt ratio falls below 12.5% and the debt-to-capital ratio increases above 60%.

Financial Information

	For the year ended December 31				
	2020	**2019**	**2018**	**2017**	**2016**
Cash flow/Total debt (%)[1]	12.7	13.7	13.0	13.2	13.5
Total debt in capital structure (%)[1, 2]	56.1	56.6	56.7	53.3	53.0
EBIT gross interest coverage (times)[1]	2.98	2.96	2.87	2.65	2.77

1 Adjusted for operating leases.
2 Adjusted for accumulated other comprehensive income.

Issuer Description

HOI is a fully owned subsidiary of Hydro One Limited (HOL; rated "A" with a Stable trend by DBRS Morningstar) and is the largest electricity transmission and distribution company in Ontario. The Company owns and operates more than 30,000 circuit kilometres (km) of high-voltage transmission lines and approximately 124,000 circuit km of low-voltage distribution lines, serving nearly 1.4 million customers.

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 the Company a reasonable opportunity to recover operating and capital costs and earn the approved rates of return. HOI's deemed capital structure (debt-to-equity of 60%:40%) has remained unchanged for several years. DBRS Morningstar 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, and is connected to 38 local distribution companies (including HOI’s own distribution business) and 82 large directly connected industrial customers. The Company’s transmission system is also interconnected to systems in Manitoba, Michigan, Minnesota, New York, and Québec through interties. Load growth is expected to be modest and in line with economic growth in the province. The distribution business serves nearly 1.4 million customers, or approximately 26% of the province’s customers.

3. Reasonable financial profile

HOI continues to maintain a reasonably healthy balance sheet. Although the cash flow-to-debt metric has been pressured in recent years, overall key credit metrics have remained reasonable for the current rating category (debt-to-capital ratio at 56.1%, cash flow-to-debt at 12.7%, and EBIT interest coverage at 2.98 times (x) for 2020).

Challenges

1. High level of planned capex

The Company has a large capital program that is expected to continue over the next several years and could pressure credit metrics. Capex was approximately $1.8 billion for 2020 (approximately $1,157 million for transmission and approximately $712 million for distribution), with a plan for approximately $10.0 billion in the next five years. A major part of HOI's capital program is for essential replacement of aging infrastructure to maintain the reliability of aging transmission and distribution assets.

2. High dividend payouts

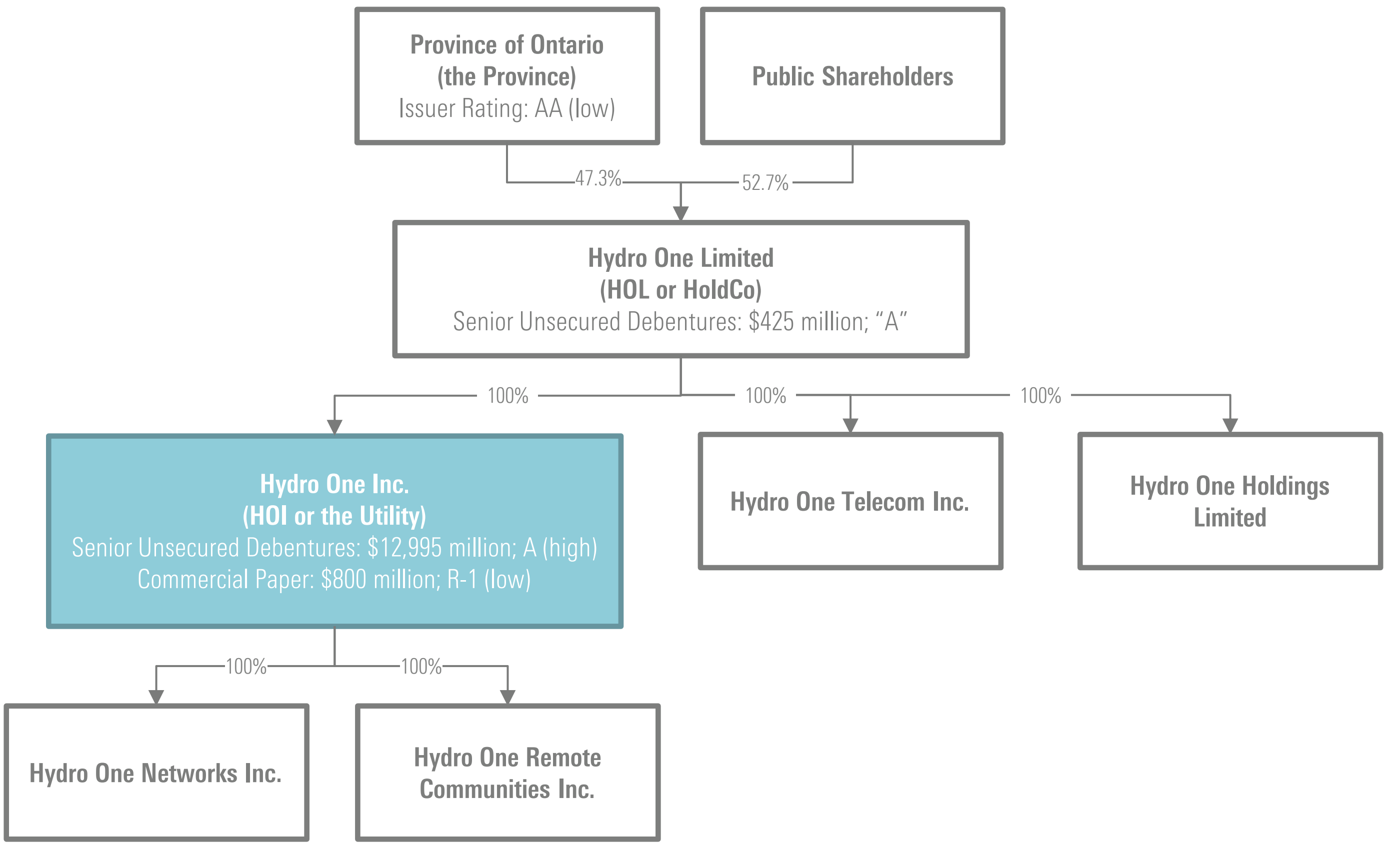
HOI's dividend payout ratio (dividends relative to net earnings) is high in order to support HOL's dividend policy (payout approximately 70% to 80% of consolidated net income). DBRS Morningstar expects the Company's dividend payout ratio to remain high in order to meet HOL's dividend objectives; consequently, 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

HOI's earnings can be affected by weather patterns, seasonality, and economic conditions. The OEB approves the Company's transmission and distribution rates based on forecast electricity load and consumption levels. Cooler summers and warmer winters could reduce demand for electricity below forecast levels and negatively affect revenues. 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 to offset the financial impacts of unanticipated changes in electricity demand or in costs. However, this risk is expected to be partially mitigated as the OEB has implemented a fixed monthly distribution charge for residential customers and HOI is currently phasing in a fixed monthly rate for all its residential customers by 2024. However, some seasonality will remain because a major part of the Company's earnings are generated from transmission revenues.

Ownership Structure

Simplified Organizational Structure



As at December 31, 2020.
Source: HOL.

- 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.
    - In May 2017, the Province completed a further secondary offering of 120 million common shares of HOL.
- HOI is 100% owned by HOL, which is in turn 47.3% owned by the Province, with the remainder held by public shareholders.
- HOI's major subsidiaries include two regulated utilities, Hydro One Networks Inc. (HONI) and Hydro One Remote Communities Inc. (Remotes).
    - HONI carries out the rate-regulated transmission and distribution businesses.
    - Remotes generates and supplies electricity to remote communities in northern Ontario. This segment is 100% debt-financed and operates as a breakeven company with no return on equity (ROE).

- HOI also owns Hydro One Sault Ste. Marie Limited Partnership (HOSSM), Bruce to Milton Limited Partnership (B2M LP), and Niagara Reinforcement Limited Partnership (NRLP).
    - HOSSM owns transmission infrastructure in the East Lake Superior area.
    - HOI has a 66% interest in B2M LP, which operates a transmission line that runs from the Bruce Nuclear Generation Complex to HOI's Milton Switching Station.
    - HOI has a 55% interest in NRLP, which operates a transmission line in the Niagara area.
- Hydro One Telecom Inc. carries out a nonregulated telecommunications business.
- Hydro One Holdings Limited was established to hold Avista Corporation (Avista). In January 2019, HOL and Avista called off the acquisition.

Earnings and Outlook

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Net revenues	3,396	3,331	3,211	3,072	3,075
EBITDA	2,275	2,239	2,066	1,968	1,926
EBIT	1,500	1,469	1,326	1,248	1,247
Gross interest expense	503	497	461	468	448
Net income before nonrecurring items	944	952	854	711	714
Reported net income	1,792	952	(31)	711	730
Return on equity (%)	9.2	9.7	8.3	7.9	9.6
Segmented Reported EBIT					
Transmission	878	823	829	770	787
Distribution	613	653	520	502	496
Other	(5)	(7)	(23)	(24)	(20)
Total EBIT	**1,486**	**1,469**	**1,326**	**1,248**	**1,263**
Transmission rate base[1]	13,185	12,609	11,870	11,251	10,775
Approved return on equity - Transmission (%)[2]	8.52	9.00	9.00	8.78	9.19
Actual return on equity - Transmission (%)[2]	9.30	9.50	11.08	9.03	10.02
Distribution rate base	8,505	8,101	7,852	7,389	7,056
Approved return on equity - Distribution (%)	9.00	9.00	9.00	8.78	9.19
Actual return on equity - Distribution (%)	11.30	10.90	8.07	7.94	8.41

1 Includes HONI, B2M LP, and HOSSM.
2 HONI only.

2020 Summary

- HOI's earnings are relatively stable, supported by a reasonable regulatory environment, extensive franchise area, and a diverse customer base that is growing at a steady rate.
- The Company's earnings in 2020 were stable compared with 2019 results.
    - EBIT for the transmission segment increased because of higher rates approved by the OEB.

  - EBIT for the distribution segment decreased as earnings in 2019 had included 2018 foregone revenue following the OEB's decision on HOI's 2018 to 2022 Custom IR application. This was partly offset by higher rates approved for the year.
  - Operating, maintenance, and administrative expenses also increased because of costs related to the coronavirus pandemic, including the temporary stand-down of the workforce.
- Actual net income included the reversal of a $867 million impairment for the deferred income tax asset as well as $14 million of bad debt expense related to the coronavirus pandemic.

2021 Outlook

- DBRS Morningstar expects HOI's earnings to remain relatively steady in 2021.
  - Revenues for transmission and distribution operations should benefit from annual increases as part of the Custom IR plans. This will be largely offset by inflationary increases for operating costs and higher depreciation from the growing rate base.
- DBRS Morningstar notes there is uncertainty on how the ongoing coronavirus pandemic will affect the Company's earnings for 2021.
  - DBRS Morningstar does not expect a significant increase in bad debt expense or for throughputs to be substantially affected for the year. However, higher-than-expected expenses related to the coronavirus pandemic could negatively affect HOI's earnings.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Net income before nonrecurring items	944	952	854	711	714
Depreciation & amortization	775	770	740	720	679
Deferred income taxes and other	51	18	25	88	123
Cash flow from operations	**1,770**	**1,740**	**1,619**	**1,519**	**1,516**
Dividends[1]	(608)	(751)	(559)	(550)	(611)
Capital expenditures	(1,835)	(1,622)	(1,524)	(1,527)	(1,634)
Free cash flow (bef. working cap. changes)	**(673)**	**(633)**	**(464)**	**(558)**	**(729)**
Changes in non-cash work. capital	159	27	(50)	63	168
Changes in regulatory assets	68	(48)	35	112	(16)
Net free cash flow	**(446)**	**(654)**	**(479)**	**(383)**	**(577)**
Acquisitions & long-term investments	(126)	0	0	0	(224)
Net equity change	0	(486)	0	0	0
Net debt change[1]	1,284	661	970	344	776
Other	(7)	(6)	1	(9)	(16)
Change in cash	**705**	**(485)**	**492**	**(48)**	**(41)**
Total debt	13,984	12,692	12,447	11,482	11,149
Cash flow/Total debt (%)[2]	12.7	13.7	13.0	13.2	13.5
Total debt in capital structure (%)[2, 3]	56.1	56.6	56.7	53.3	53.0
EBIT gross interest coverage (times)[2]	2.98	2.96	2.87	2.65	2.77
Dividend payout ratio (%)	64.7	78.9	65.5	77.4	85.1

1 Includes preferred shares of $486 million in 2017 that DBRS Morningstar has treated as debt because the shares were redeemed in 2019.
2 Adjusted for operating leases.
3 Adjusted for accumulated other comprehensive income.

2020 Summary

- HOI's key credit metrics remained supportive of the current ratings.
    - The Company's cash flow-to-debt ratio weakened because of the timing of debt issuances during the year. The debt-to-capital and EBIT-interest coverage ratios were steady.
- Cash flow from operations was in line with 2019 results.
- Capex increased as HOI continued investing in maintaining and reinforcing the grid.
- Acquisitions of $126 million reflects the purchase of Peterborough Distribution Inc. and Orillia Power Distribution Corporation.
- Dividends were to maintain the regulatory capital structure broadly in line with the regulatory construct.
- The Company issued $2.3 billion of long-term debt during the year to pay down CP, repay $653 million of note maturities, prefund $500 million of notes maturing in February 2021, and fund the capex program.

2021 Outlook

- DBRS Morningstar expects HOI's key credits to remain reasonable for the A (high) rating.
- Cash flow from operations is expected to remain steady, in line with earnings.
    - DBRS Morningstar notes the Company's cash flows should increase by $50 million to $60 million annually following the approval of its application with the OEB on the deferred tax asset.
- HOI has forecast capex of $1.9 billion for the year, with the majority for sustainment projects.
- DBRS Morningstar 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 Morningstar expects dividends to remain high.

Debt and Liquidity

Liquidity

(CAD millions - as at December 31, 2020)	Amount	Draw	Available	Maturity
Cash & cash equivalents	712	-	**712**	
Revolving standby credit facility	2,300	800	**1,500**	June 2024
Total	**3,012**	**800**	**2,212**	

- The Company's liquidity profile remains reasonable and adequate for its normal operating requirements.
- HOI has a revolving credit facility of $2.3 billion maturing in June 2024. The CP program is backstopped by the revolving credit facility. As of December 31, 2020, approximately $800 million of CP was outstanding.

Long-Term Debt Maturities

(CAD millions - as at December 31, 2019)	2021	2022	2023	2024	2025	Thereafter	Total
Principal repayments	803	604	731	700	750	9,545	**13,133**
% of total	6	5	6	5	6	73	**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.
    - In 2020, the Company issued $2.3 billion under its Medium Term Note program, the proceeds of which were used to repay long- and short-term debt, and to fund the capex program.
- HOI has credit 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, 2020, the Company was in compliance with all of the covenants and limitations.

Major Projects and Acquisitions

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2020 (CAD millions)	In-Service Target Date
Richview Transmission Station Circuit Breaker Replacement	118	115	2021
Bruce A Transmission Station	146	144	2021
East-West Tie Station Expansion	160	129	2022
Beck #2 Transmission Station Circuit Breaker Replacement	136	89	2023
Bruce B Switching Station Circuit Breaker Replacement	146	50	2024
Middleport Transmission Station Circuit Breaker Replacement	123	71	2025
Lennox Transmission Station Circuit Breaker Replacement	152	91	2026
Leamington Area Transmission Reinforcement	525	54	2026

- Most of HOI's capex is for sustainment purposes (60% for 2021).
- Development projects include the East-West Tie Station Expansion, which involves expanding a transformer station in order to connect the new East-West Tie transmission line to the station, and the Leamington Area Transmission Reinforcement, which involves a new transmission station and 13 km transmission line.
- In April 2020, the OEB approved for HONI to acquire the business and distribution assets of Peterborough Distribution Inc. The acquisition closed in August 2020 for $105 million.
- In April 2020, the OEB approved for HONI to acquire Orillia Power Distribution Corporation. The acquisition closed in September 2020 for $41 million.

Regulation

Regulation Overview

- HOI is regulated by the OEB and operates under a supportive regulatory environment. The Company has a good track record of prudently managing its regulatory risk.
- Both of HONI's transmission and distribution businesses operate under Custom IR.
    - The Custom IR framework is a hybrid between COS and an incentive rate mechanism (IRM). The rate setting for the term is based on the Company's forecasts and the OEB's incentive rate analysis using productivity benchmarking.

- Custom IR is suited to utilities with large, broad, multiyear investment needs that require certainty of funding several years in advance.
- Both the transmission and distribution segments operate with a deemed capital structure of 60% debt (56% long term and 4% short term) and 40% equity.
- Going forward, HOI is expected to file a single five-year rate application (2023 to 2027) for both the transmission and distribution businesses, as required by the OEB.
- In July 2020, the Ontario Divisional Court set aside the OEB's decision that the deferred tax asset that resulted from the transition from the payments in lieu of tax program to the federal and provincial tax regimes should be shared with ratepayers. The Ontario Divisional Court agreed with the Company that the deferred tax asset should have been allocated entirely to shareholders.
  - Following the decision, HOI reversed the $867 million impairment it had recorded in 2018.
  - In April 2021, the OEB approved a refund of misallocated future tax savings of $257 million from ratepayers to shareholders over a two-year period beginning July 1, 2021. The OEB also acknowledged that no future tax savings from the sale of HOL shares should be allocated to ratepayers. DBRS Morningstar expects the Company's cash flows should increase by $50 million to $60 million annually.

Transmission

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Transmission rate base[1]	13,185	12,609	11,870	11,251	10,775
Deemed equity (%)	40.00	40.00	40.00	40.00	40.00
Allowed ROE - Transmission (HONI) (%)	8.52	9.00	9.00	8.78	9.19
Allowed ROE - Transmission (B2M LP) (%)	8.52	8.98	9.00	8.78	9.19
Allowed ROE - Transmission (HOSSM) (%)	9.19	9.19	9.19	9.19	9.19
Allowed ROE - Transmission (NRLP) (%)	8.52	N/A	N/A	N/A	N/A
Actual ROE - Transmission (HONI) (%)	9.30	9.50	11.08	9.03	10.02

1 Includes HONI, B2M LP, and HOSSM.

- In April 2020, the OEB approved HONI's 2020–22 transmission Custom IR application.
  - Revenues for 2020 were based on COS while subsequent years will increase by an Revenue Cap Index (RCI) based on inflation, productivity, stretch, and capital factors.
  - The productivity factor was set at 0% while the stretch factor was set at 0.30%. An additional 0.15% stretch factor will be applied to the capital factor.
  - The OEB also approved an earnings sharing mechanism (ESM) that provides for 50% of the savings that result in an actual regulatory ROE in excess of 100 basis points (bps) over the OEB-approved ROE to be shared with customers.
  - For 2020, the OEB approved a revenue requirement of $1,586 million effective January 1, 2020, based on an ROE of 8.52%.
  - The OEB also approved a capex budget of $3.5 billion over the three-year term.

- In December 2020, the OEB approved HONI's 2021 transmission revenue requirement of $1,660 million based on an RCI of 4.58%, with inflation of 2.0%, productivity and stretch factor of 0.3%, and a capital factor of 3.03% less a 0.15% incremental capital stretch factor.
- In January 2020, the OEB approved B2M LP's 2020 to 2024 transmission revenue requirement.
    - The OEB approved the 2020 revenue requirement of $33.2 million.
    - For 2021 to 2024, revenue will increase annually by an RCI based on inflation less a Settlement Capital Adjustment Factor (SCAF) of 0.6%.
    - The application also includes an ESM that allows customers to share 50% of earnings that exceed the regulatory ROE by more than 100 bps in any year.
    - In November 2020, the OEB approved B2M LP's 2021 revenue requirement of $33.0 million based on an RCI of 1.4% (inflation of 2.0% less a SCAF of 0.6%).
- HOSSM currently operates under a 10-year deferred rebasing period until 2026. Rates are adjusted annually by an RCI based on inflation less a productivity and stretch factor.
    - In December 2019, the OEB approved HOSSM's 2020 revenue requirement of $40.8 million based on an RCI of 1.5% (inflation of 1.8% less a stretch factor of 0.3%).
    - In December 2020, the OEB approved HOSSM's 2021 revenue requirement of $41.5 million based on an RCI of 1.7% (inflation of 2.0% less a stretch factor of 0.3%).
- In April 2020, the OEB approved NRLP's 2020 to 2024 transmission revenue requirement.
    - The OEB approved 2020 revenue requirement of $8.7 million.
    - For 2021 to 2024, revenue will increase annually by an RCI based on 50% of inflation less a SCAF of 0.6%.
    - The application also includes an ESM that allows customers to share 50% of earnings that exceed the regulatory ROE by more than 100 bps in any year.
    - In December 2020, the OEB approved NRLP's 2021 revenue requirement of $8.2 million based on an RCI of 0.4% (50% of inflation at 1.0% less a SCAF factor of 0.6%).

Distribution

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Distribution rate base	8,505	8,101	7,852	7,389	7,056
Deemed equity (%)	40.00	40.00	40.00	40.00	40.00
Allowed ROE - Distribution (%)	9.00	9.00	9.00	8.78	9.19
Actual ROE - Distribution (%)	11.30	10.90	8.07	7.94	8.41

- In March 2019, the OEB approved HONI's Custom IR application for 2018 to 2022 distribution rates.
    - Revenues for 2018 were based on COS while subsequent years will increase by an RCI based on inflation, productivity, stretch, and capital factors.
    - The OEB also approved an ESM that provides for 50% of the savings that result in an actual regulatory ROE in excess of 100 bps over the OEB-approved ROE to be shared with customers.

- For 2020, the OEB approved the revenue requirement of $1,539 million based on an RCI of 2.76% with inflation of 2.0%, a productivity factor of 0%, a stretch factor of 0.45%, and a capital factor of 1.21% (1.36% less an additional stretch factor of 0.15%).
- For 2021, the OEB approved the revenue requirement of $1,596 million based on an RCI of 3.70% with inflation of 2.2%, a productivity factor of 0%, a stretch factor of 0.45%, and a capital factor of 1.95% (2.10% less an additional stretch factor of 0.15%).

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows HOI's transmission and distribution businesses to have a deemed equity of 40%, which has been consistent historically.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	ROE for the distribution businesses was set at 9.00% for 2018 to 2022. ROE for the transmission business was set at 8.52% for 2020 to 2022.
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 preapproved 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	HONI's distribution business operates under Custom IR for 2018–22. The transmission business operates under Custom IR for 2020–22.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The government of Ontario plays a significant role in the electricity sector in Ontario, given that the majority of the utilities are government owned (HOI is 47% owned by the Province). Furthermore, stakeholders, such as the Independent Electricity System Operator, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
7. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	HOI has a limited history of stranded costs. All 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 provincewide rate freezes.

Balance Sheet

(CAD millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2020**	**2019**	**2018**	**Liabilities & Equity**	**2020**	**2019**	**2018**
Cash & equivalents	712	7	492	Short-term borrowings	811	1,151	1,252
Accounts receivable	719	699	625	Accounts payable	789	787	749
Inventories	23	21	20	Current portion long-term debt	806	653	731
Prepaid expenses & other	580	593	403	Other current liabilities	554	480	316
Total Current Assets	**2,034**	**1,320**	**1,540**	**Total Current Liabilities**	**2,960**	**3,071**	**3,048**
Net fixed assets	22,619	21,489	20,605	Long-term debt	12,367	10,888	9,978
Future income tax assets	16	643	964	Deferred income taxes	56	61	55
Goodwill & intangibles	885	780	734	Regulatory liabilities	231	167	326
Regulatory assets	4,571	2,676	1,721	Provisions and other liabilities	3,621	3,007	2,164
Investments & others	8	9	5	Minority interest	94	79	70
				Preferred shares	0	0	486
				Common equity	10,804	9,644	9,442
Total Assets	**30,133**	**26,917**	**25,569**	**Total Liabilities & Equity**	**30,133**	**26,917**	**25,569**

Ratios

For the year ended December 31					
Balance Sheet & Liquidity & Capital Ratios	**2020**	**2019**	**2018**	**2017**	**2016**
Current ratio	0.69	0.43	0.51	0.40	0.53
Cash flow/Total debt (%)	12.7	13.7	13.0	13.2	13.5
Cash flow/Total debt (%)[1]	12.7	13.7	13.0	13.2	13.5
Total debt in capital structure (%)	56.1	56.6	56.7	53.3	53.0
Total debt in capital structure (%)[1, 2]	56.1	56.6	56.7	53.3	53.0
Cash flow/Total debt (%)[1]	12.7	13.7	13.0	13.2	13.5
(Cash flow-dividends)/Capex (times)	0.63	0.61	0.70	0.63	0.55
Dividend payout ratio (%)	64.7	78.9	65.5	77.4	85.1
Coverage Ratios (times)					
EBIT gross interest coverage	2.98	2.96	2.87	2.65	2.77
EBIT gross interest coverage[1]	2.98	2.96	2.87	2.65	2.77
EBITDA gross interest coverage	4.52	4.51	4.48	4.21	4.30
Fixed-charge coverage	2.98	2.96	2.87	2.65	2.77
Profitability Ratios					
EBITDA margin (%)	57.0	67.2	64.3	64.1	62.6
EBIT margin (%)	44.2	44.1	41.3	40.6	40.6
Profit margin (%)	27.8	28.6	26.6	23.1	23.2
Return on equity (%)	9.2	9.7	8.3	7.9	9.6
Return on capital (%)	4.7	4.9	4.5	4.5	5.1

1 Adjusted for operating leases.
2 Adjusted for accumulated other comprehensive income.

Rating History

	Current	2020	2019	2018	2017	2016
Issuer Rating	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)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $2.3 billion.

Related Research

- "DBRS Morningstar Finalizes Provisional Rating on Hydro One Limited's Senior Unsecured Debentures at "A," Stable Trend," October 15, 2020.
- "DBRS Morningstar Assigns Ratings of "A" With Stable Trends to the Issuer Rating and Senior Unsecured Debentures of Hydro One Limited," September 21, 2020.

Previous Actions

- "DBRS Morningstar Assigns Ratings of A (high) with Stable Trends to Hydro One Inc.'s $1.2 Billion Medium-Term Notes Issues," October 9, 2020.
- "DBRS Morningstar Confirms Ratings of Hydro One Inc. at A (high)/R-1 (low), Stable Trends," April 9, 2020.

Previous Report

- Hydro One Inc.: Rating Report, April 16, 2020.

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.dbrsmorningstar.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.

About DBRS Morningstar

DBRS Morningstar is a full-service global credit ratings business with approximately 700 employees around the world. We're a market leader in Canada, and in multiple asset classes across the U.S. and Europe.

We rate more than 3,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

DBRS Morningstar is empowering investor success as the go-to source for independent credit ratings. And we are bringing transparency, responsiveness, and leading-edge technology to the industry.

That's why DBRS Morningstar is the next generation of credit ratings.

Learn more at dbrsmorningstar.com.

The DBRS Morningstar group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings GmbH (Frankfurt, Germany)(EU CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings Limited (England and Wales)(UK CRA, NRSRO affiliate, DRO affiliate). For more information on regulatory registrations, recognitions and approvals of the DBRS Morningstar group of companies, please see: https://www.dbrsmorningstar.com/research/225752/highlights.pdf.

The DBRS Morningstar group of companies are wholly-owned subsidiaries of Morningstar, Inc.

RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2020)

Transmission:

$M	**Total per Exhibit A-06-02-02**	**Adjustments**	**Regulated Results**
	(a)	**(b)**	**(c)**
REVENUE			
Transmission Tariff	1,619	(23)	1,596
Other	62		62
COSTS			
Operation, maintenance, and administration	414		414
Depreciation, amortization, and asset removal costs	441		441
Income before financing charges and income tax expense	826		803
Financing charges	264	56	320
Income tax expense (recovery)	(54)	77	23
NET INCOME	**616**		**460**

Certain adjustments are required to reconcile from the audited financial statements to regulated net income. These adjustments are consistent with those presented in the annual RRR Regulated ROE Filing (section 3.1.4). The accounting treatment of any non-utility business has segregated activities from rate regulated activities.

<u>Distribution</u>

$M	**Total per Exhibit A-06-02-04**	**Adjustments**	**Utility Income**
REVENUE			
Energy sales	5,109		5,109
Rural rate protection	242		242
Other	35		35
TOTAL REVENUE	**5,386**		**5,386**
COSTS			
Purchased power	3,796		3,796
Operation, maintenance & administration	571		571
Depreciation, amortization and asset removal costs	417		417
TOTAL COSTS	**4,784**		**4,784**
Income before financing charges & income tax expense	**602**		**602**
Financing charges	188	28	216
Income before income taxes	**414**		**386**
Income tax expense (recovery)	(1)	40	39
NET INCOME	**415**		**347**

Certain adjustments are required to reconcile from the audited financial statements to regulated net income. These adjustments are consistent with those presented in the annual RRR Regulated ROE Filing (section 3.1.5.6). The accounting treatment of any non-utility business has segregated activities from rate regulated activities.

PROSPECTUS FOR MOST RECENT FINANCING

This Exhibit includes copies of the prospectus for recent public debt offerings.

- Attachment 1: Short Form Base Shelf Prospectus, dated: April 14, 2020

This page left blank intentionally.

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

<u>New Issue</u> April 14, 2020

hydroOne

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 April 14, 2020, 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.

TABLE OF CONTENTS

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 February 12, 2020 (the "AIF");

(b) the statement of executive compensation dated March 26, 2020 incorporated by reference in the AIF (the "Statement of Executive Compensation");

(c) the comparative audited consolidated financial statements of the Company, and the notes thereto, as at and for the fiscal years ended December 31, 2019 and 2018, together with the report of the auditors thereon dated February 11, 2020 (the "Annual Financials"); and

(d) management's discussion and analysis of financial results for the year ended December 31, 2019.

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 (d) 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 (excluding any statement of executive compensation incorporated by reference therein), 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. Upon a new statement of executive compensation being filed by the Company with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this short form prospectus and incorporated by reference in the Company's then current annual information form, the previous statement of executive compensation 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 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 and capital expenditures, 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; no unfavourable changes in environmental regulation; the continued use and availability of U.S. GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; no significant changes to the Company's current credit ratings; no unforeseen impacts of new accounting pronouncements; 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 Ontario's largest electricity transmission and distribution utility. 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 segments: (i) transmission business; (ii) distribution business; and (iii) other.

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 approximately 66% interest in B2M Limited Partnership, a limited partnership between the Company and the Saugeen Ojibway Nation with respect to the Bruce-to-Milton transmission line and the Company's approximately 55% interest in Niagara Reinforcement Limited Partnership ("**NRLP**"), a limited partnership formed for the purpose of operating a new 230 kV transmission line in the Niagara region. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that are subject to approval by the Ontario Energy Board. The Company's transmission business represented approximately 56% of its total assets as at December 31, 2019, and approximately 50% of its total revenue, net of purchased power, in 2019. 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 and NRLP, which the Company controls.

The Company's distribution business consists of owning, operating and maintaining its distribution system, which the Company owns primarily through Hydro One Networks Inc., the largest local distribution company in Ontario. The Company's distribution system is also the largest in Ontario, and services a predominantly rural territory. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are subject to approval by the Ontario Energy Board. The Company's distribution business represented approximately 37% of its total assets as at December 31, 2019 and approximately 50% of its total revenues, net of purchased power, in 2019.

The Company's other 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 segment represented approximately 7% of the Company's total assets as at December 31, 2019, and 0% of its total revenues, net of purchased power, in 2019.

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.

RECENT DEVELOPMENTS

On February 28, 2020, the Company closed an offering of $1.1 billion of medium term notes consisting of $400 million aggregate principal amount of 1.76% Notes due 2025 (Series 45), $400 million aggregate principal amount of 2.16% Notes due 2030 (Series 46) and $300 million aggregate principal amount of 2.71% Notes due 2050 (Series 47). The Company intends to use the proceeds from the offering to repay maturing long term and short term debt and for general corporate purposes. The medium term notes were offered pursuant to the short form base shelf prospectus of the Company dated March 8, 2018.

CREDIT RATINGS

As of the date of this short form prospectus, the Notes have been rated A- with a stable outlook by S&P Global Ratings ("S&P") and A (high) with a stable trend by DBRS Limited ("DBRS") and have been provisionally rated A3 with a stable outlook by Moody's Investors Service ("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" or "low" 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 1 indicates a ranking in the higher end of that generic rating category and a 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. 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. 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").

Notwithstanding the foregoing, the holder of a TFSA or RDSP, the annuitant under an RRSP or RRIF or the subscriber of an RESP may be subject to a penalty tax if the Notes are "prohibited investments" (as defined in the Tax Act) for the TFSA, RDSP, RRSP, RRIF or RESP, as applicable. 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, as the case may be, (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

Except as described below, 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.

Since December 31, 2019, the Company has issued $1.1 billion of debt in the form of medium term notes. See "Recent Developments".

EARNINGS COVERAGE RATIOS

For the twelve months ended December 31, 2019, the Company's consolidated income before provision for corporate income taxes and interest expense (net of capitalized interest) was $1.469 billion. Interest expense (net of capitalized interest) for this period was $460 million, and including capitalized interest, was $508 million.

The following table sets forth the earnings coverage ratio for the Company for the twelve month period ended December 31, 2019, based on audited information, without giving effect to any Notes to be issued under this short form prospectus:

	December 31, 2019
Earnings coverage on long-term debt obligations(1)(2)	2.87

(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, 2019 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.

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".

Negative Pledge

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 April 14, 2020, 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 April 14, 2020, 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

In the 12-month period prior to the date hereof, the Company has issued the following tranches of medium term notes under its short form prospectus dated March 8, 2018:

Notes	Date of Issuance	Principal Amount	Sale Price (per $100 principal amount)	Gross Proceeds
1.76% Notes due 2025 (Series 45)	February 28, 2020	$400,000,000	99.976	$399,904,000
2.16% Notes due 2030 (Series 46)	February 28, 2020	$400,000,000	99.982	$399,928,000
2.71% Notes due 2050 (Series 47)	February 28, 2020	$300,000,000	99.918	$299,754,000

TRADING PRICE AND VOLUME

The Company’s 4.59% Notes due 2043 (Series 29) (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 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 the Dealers, 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 any other federal tax legislation or considerations or any 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 or any of the Dealers 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 a purchaser (i) an interest in which is a "tax shelter investment", (ii) 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) 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.

In the event the Notes are issued at a discount from their face value, and generally depending on the amount of such discount, a Resident Holder may be required to include an additional amount in computing income, either in accordance with the deemed interest accrual rules contained in the Tax Act or in the taxation year in which the discount is received or receivable by the Resident Holder. A Resident Holder should consult its tax advisor in these circumstances, as the treatment of the discount will vary with the facts and circumstances giving rise to the discount.

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 that taxation 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 that taxation 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 taxation 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 (i) is not, and is not deemed to be, resident in Canada, (ii) 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 (iii) 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:

Risks Related to the Company

COVID-19 Pandemic

The recent COVID-19 pandemic could materially adversely impact the Company. The extent of any such adverse impact on the Company is uncertain at this time, and may depend on the length and severity of the pandemic, as well as any resultant government regulations, guidelines and actions. The COVID-19 pandemic, the resultant government regulations, guidelines and actions, and related adverse changes in general economic and market conditions could impact, in particular: the Company's operations and workforce, including its ability to complete planned operating and capital work programs within scope and budget; certain financial obligations, including pension contributions and other post-retirement benefits, as a result of changes in prevailing market conditions; expected revenues; reductions in overall electricity consumption and load, both short term and long term; overdue accounts and bad debt increases as a result of changes in the ability of the Company's customers to pay; liquidity and the Company's ability to raise capital; the timing of increased rates; the ability to recover incremental costs linked to the pandemic; the Company's ability to file regulatory filings on a timely basis; timing of regulatory decisions and the impacts those decisions may have on the Company or its ability to implement them; and customer and stakeholder needs and expectations.

The Company also faces risks and costs associated with implementation of business continuity plans and modified work conditions, including the risks and costs associated with maintaining or reducing its workforce, making the required resources available to its workforce to enable them to continue essential work, including remotely where possible, and to keep its workforce healthy, as well as risks and costs associated with recovery of normal operations. Furthermore, the Company is dependent on third party providers for certain activities, and relies on a strong international supply chain, which may also be adversely impacted, and which, in turn, could materially adversely impact the Company.

Risks Related to the Notes

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. The Company cannot predict what actions rating agencies may take in the future, positive or negative, including in response to government action or inaction relating to or impacting the Company. In addition, negative changes in the Company's credit rating may affect the credit ratings of the Notes and can affect the cost at which the Company can access the debt market and increase the Company's cost of debt.

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.

EXEMPTION

Pursuant to a decision of the *Autorité des marchés financiers*, on March 31, 2020, the Company was granted temporary relief from the requirement to file with the preliminary short form base shelf prospectus the French language version of the Statement of Executive Compensation, which document is incorporated by reference in this short form base shelf prospectus, provided that such document in the French language is filed no later than the time of filing of this short form base shelf prospectus. The French language version of the Statement of Executive Compensation has now been filed on SEDAR.

AUDITORS, REGISTRAR AND TRANSFER AGENT

KPMG LLP, Chartered Professional Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario M5H 2S5, is the auditor of the Company and has confirmed with respect to the Company, that it is independent 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

Anne Giardini, a director of the company, resides outside of Canada. Ms. Giardini 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: April 14, 2020

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) Mark Poweska President and Chief Executive Officer	(Signed) Chris Lopez Chief Financial Officer

On behalf of the Board of Directors:

(Signed) Timothy Hodgson Director	(Signed) Russel Robertson Director

CERTIFICATE OF DEALERS

Dated: April 14, 2020

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) Roger Casgrain	By: (Signed) Sean Gilbert
DESJARDINS SECURITIES INC.	LAURENTIAN BANK SECURITIES INC.	NATIONAL BANK FINANCIAL INC.
By: (Signed) Ryan Godfrey	By: (Signed) Jean-François Gauthier	By: (Signed) John Carrique
RBC DOMINION SECURITIES INC.	SCOTIA CAPITAL INC.	TD SECURITIES INC.
By: (Signed) Rob Brown	By: (Signed) Fanny Doucet	By: (Signed) Andrew Becker

HYDRO ONE LIMITED - HISTORICAL YEAR ANNUAL REPORT (2019 AND 2020)

Included in this exhibit are Hydro One Limited's Annual Reports:

- Attachment 1: 2019 Annual Report
- Attachment 2: 2020 Annual Report

This page left blank intentionally.

Filed: 2021-08-05
EB-2021-0110
Exhibit A-6-6
Attachment 1
Page 1 of 28

Energizing Life

Contents

The Power of Connection.
Energizing Life.

Hydro One energizes life for people and communities, helping Ontarians live a better and brighter future. Through our network of businesses, we are growing and evolving to meet the expectations of the shareholders, regulators, Indigenous peoples and customers we serve.

85.7%

Residential & small business customer satisfaction

$1.7billion

In capital investments to our grid to ensure safe and reliable power for communities across Ontario

A Network Built for the Possibilities of Tomorrow

Who We Are

Hydro One Limited (TSX: H)

Hydro One Limited, through its wholly owned subsidiaries, is Ontario's largest electricity transmission and distribution provider with approximately 1.4 million valued customers, approximately $27.1 billion in assets as at December 31, 2019, and annual revenues in 2019 of approximately $6.5 billion.

Our team of approximately 8,800 skilled and dedicated employees proudly build and maintain a safe and reliable electricity system which is essential to supporting strong and successful communities. In 2019, Hydro One invested approximately $1.7 billion in its transmission and distribution networks and supported the economy through buying approximately $1.5 billion of goods and services.

We are committed to the communities where we live and work through community investment, sustainability and diversity initiatives. We are designated as a Sustainable Electricity Company by the Canadian Electricity Association.

Hydro One Limited's common shares are listed on the TSX and certain of Hydro One Inc.'s medium term notes are listed on the NYSE. Additional information can be accessed at www.hydroone.com; www.sedar.com or www.sec.gov)

$6.5billion
2019 annual revenue

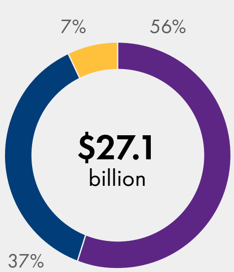
8,800
Skilled and dedicated employees

Financial Highlights

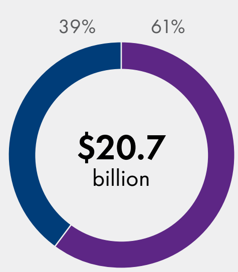
Year ended December 31 (millions of dollars, except as otherwise noted)	**2019**	2018
Revenues	**6,480**	6,150
Purchased power	**3,111**	2,899
Revenues, net of purchased power[1]	**3,369**	3,251
Operation, maintenance and administration (OM&A) costs	**1,181**	1,105
Depreciation, amortization and asset removal costs	**878**	837
Financing charges	**514**	459
Income tax expense (recovery)	**(6)**	915
Net income (loss) to common shareholders of Hydro One	**778**	**(89)**
Adjusted net income to common shareholders of Hydro One[1]	**918**	**807**
Basic earnings per common share (EPS)	**$1.30**	($0.15)
Diluted EPS	**$1.30**	($0.15)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$1.54**	$1.35
Diluted Adjusted EPS[1]	**$1.53**	$1.35
Net cash from operating activities	**1,614**	1,575
Funds from operations (FFO)[1]	**1,532**	1,572
Capital investments	**1,667**	1,575
Assets placed in-service	**1,703**	1,813
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,896**	20,485
Distribution: Electricity distributed to Hydro One customers (GWh)	**27,536**	27,338
Debt to capitalization ratio[2]	**56.3%**	55.6%

1. See section "Non-GAAP Measures" for description and reconciliation of adjusted net income, basic and diluted Adjusted EPS, FFO and revenues, net of purchased power.
2. Debt to capitalization ratio is a non-GAAP measure and has been presented as at December 31, 2019 and 2018, and has been calculated as total debt (including 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. Management believes that the debt to capitalization ratio is helpful as a measure of the proportion of debt in the Company's capital structure.

Total Assets

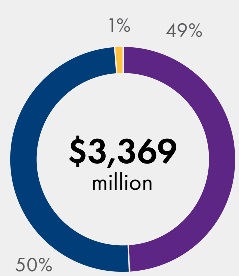


Rate Base



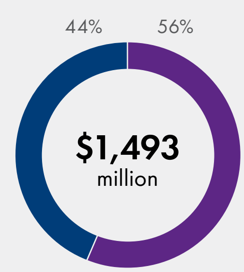
Revenues

(Net of purchased power costs)



Regulated Earnings

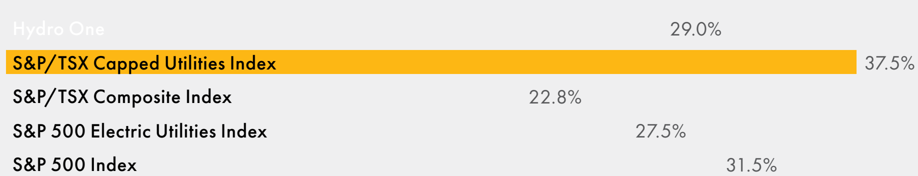
(Before financing charges and income taxes)



● Transmission ● Distribution ● Other

Total Shareholder Return (TSR)

January 1, 2019 to December 31, 2019



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 includes 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.

All figures in this document are approximate figures that are rounded to the nearest decimal place.

Hydro One's Business Network

Our Regulated Business

Transmission

Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to distribution companies and industrial customers across Ontario. Our system accounts for approximately 98%[1] of Ontario's transmission capacity with approximately 30,000 circuit kilometres of high-voltage transmission lines. We also own and operate 25 cross-border interconnections with neighbouring provinces and the United States, which allow electricity to flow into and out of Ontario.

Distribution

Our distribution system is the largest[2] in Ontario. It consists of approximately 123,000 circuit kilometres of primary low-voltage power lines serving approximately 1.4 million customers, mostly in rural areas. As well, Hydro One Remote Communities Inc. serves customers in one grid-connected and 21 off-grid communities in Ontario's far north.

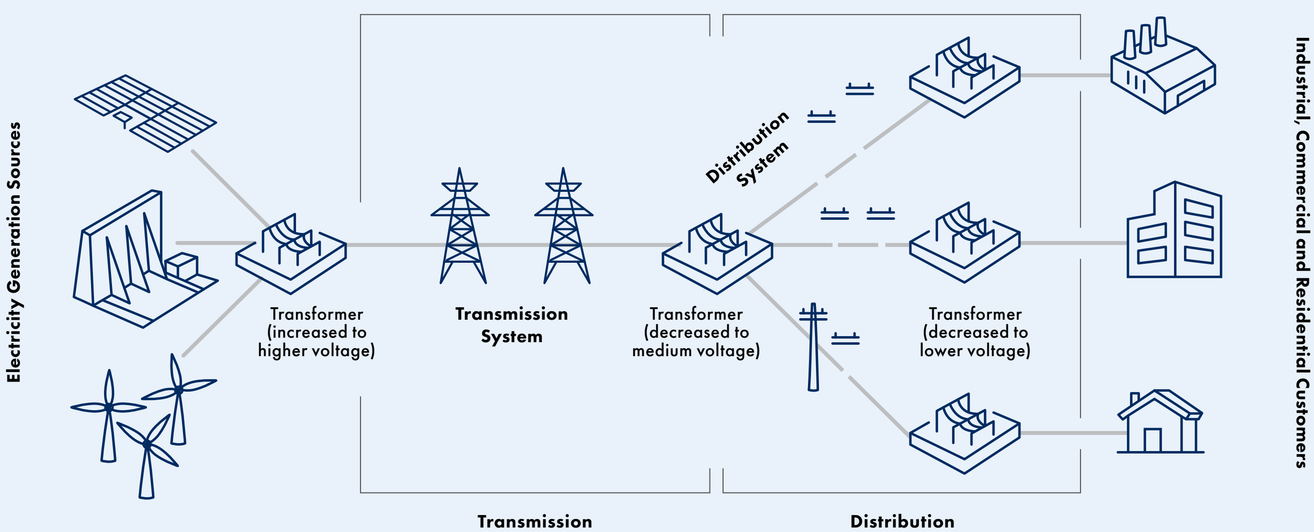
Our Unregulated Business

Our other segment consists principally of our telecommunications business, Hydro One Telecom Inc. (HOT), which provides telecommunications support for Hydro One's transmission and distribution businesses. HOT offers comprehensive communications and information technology services and solutions (cloud services, managed services and security-based services) that extend beyond the core fibre and connectivity services it has traditionally offered.

1. based on revenue approved by the OEB
2. based on customers (per OEB yearbook)

Hydro One's Role in the Ontario Electric Power System

Our transmission and distribution systems safely and reliably serve communities throughout Ontario. Our customers are suburban, rural and remote homes and businesses across the province. Our communities are proudly and safely serviced by a team of skilled and dedicated employees.



Key Highlights

1

High Customer Satisfaction

Across all lines of business including 87.2% transmission customer satisfaction, 85.7% residential and small business customer satisfaction, 89.5% First Nations customer satisfaction and 90.0% Hydro One Telecom Inc. customer satisfaction. We also earned two customer service awards from the Ontario Energy Association.

2

Leadership in Power Restoration

Recognized by the Edison Electric Institute (EEI) Emergency Assistance Award for our response efforts following the deadly California wildfires in 2018 and for helping Manitoba Hydro after a severe storm in October 2019. This complements response times within our own borders – Hydro One's Customer Average Interruption Duration Index (CAIDI), a key measure of success in delivering reliable power, improved by 9.7% in 2019.

3

Supporting Local Businesses

Remaining a substantial contributor to Ontario's economy through the purchase of local goods and services, including $41.3 million spent with Indigenous businesses in 2019.

4

Productivity Savings

A 49.3% increase in year-over-year productivity savings with $202.3 million saved in 2019 as compared to $135.5 million in 2018.

5

Reducing Costs

A 4.7%, or $51 million, reduction in annual operating costs adjusted for Avista related costs in 2019 from 2018.

6

Capital Investments

Approximately $1.7 billion in capital investments to expand the electricity grid and renew and modernize existing infrastructure.

7

Best Employer, 5th Year

For the fifth consecutive year, Hydro One has been recognized by Forbes in its list of Canada's Best Employers for 2020, underscoring our commitment to creating an engaged workforce and positive working environment.

Hydro One partnered with government and industry stakeholders, Indigenous peoples, customers, unions and other stakeholders throughout the year to achieve a number of key performance milestones.

Hydro One Drives Ontario's Economy

98%[1]
Of Ontario's transmission capacity

38
Electric utilities companies (including Hydro One's own distribution business) that are Hydro One's transmission customers

~1.4 million
Residential and business customers served by our local distribution business

83
Large industrial customers connected directly to the transmission network

1. based on revenue approved by the OEB

Timothy Hodgson
Chair

A Message From Our Chair

I am honoured to serve as Chair of this historic company, with its 115-year legacy of adding economic value through transmitting and distributing electricity to Ontario. Hydro One has an incredibly important mandate in serving the people of our province and in delivering outstanding and cost-efficient service to approximately 1.4 million customers in communities across Ontario. The Board of Directors fully supports Hydro One's focus on delivering greater value for its customers, employees, communities and shareholders.

Confident leadership, clear vision

In May, following a thorough and competitive international search process, the Board officially welcomed Mark Poweska as Hydro One's President and CEO. The Board sought a highly regarded leader in the electricity utility sector, one with a proven record in building a strong safety culture, exceeding customer expectations and improving operational performance – along with the ability to develop enduring relationships with Indigenous communities, our stakeholders, and government.

We found all of the above in Mark, whose 25-year career has included responsibility for all aspects of electricity generation, transmission and distribution operations at a major North American integrated utility. Mark's extensive experience in the electricity sector will help ensure Hydro One is strong now and even better positioned into the future.

To that end, the Board of Directors approved and fully endorses the corporate strategy that Mark and his team developed in 2019. The five-year Ontario-focused strategy sets a clear vision for Hydro One to: build a grid for the future, be the safest and most efficient utility, be a trusted partner, be an advocate for customers, as well as innovate and grow the business.

Sustainable practices, best-in-class performance

Safety remains a priority of the Board of Directors and we support management's renewed and intensified commitment to continually enhancing Hydro One's culture of safety. The Board of Directors is equally committed to supporting management's initiatives to further develop the company's sustainable business practices.

In 2019, Hydro One achieved a total return to shareholders of 29%, reflecting strong sector fundamentals and stable growth, as well as the company's ability to capture efficiencies and reduce operating costs. The Board of Directors fully supports company initiatives that have reduced its cost of capital. We are encouraged that equity market investors have re-rated our company upward relative to our publicly traded competitors and our publicly traded debt pricing has improved with the positive rating actions of key credit rating agencies.

Strong governance, diverse viewpoints

I want to thank all Board members for their oversight and deliberations this past year. On their behalf, I welcome Susan Wolburgh Jenah to Hydro One's Board of Directors. This is a timely appointment of a highly qualified individual and I know we all will benefit from Susan's exceptional experience, both leading and serving on boards of publicly traded, regulated companies.

Hydro One values diversity at all levels of the organization and our commitment extends to ensuring a gender-diverse Board of Directors. With the announcement of Susan, the composition of our Independent Non-Executive Board is 50% women and 50% men, reflecting best practices in board diversity and surpassing our Catalyst Accord commitment to maintaining at least 30% female board members. Additionally, our commitment to Indigenous representation at the Board level reflects Hydro One's understanding that it is a strategic imperative to be a best-in-class trusted partner of Indigenous communities and to be inclusive of the many customers and stakeholders we serve across the province.

Enhancing value, delivering results

Our success is due to the diligence and passion of our leaders and employees. First, on behalf of the entire Board of Directors, I want to thank all Hydro One employees for their extraordinary efforts this past year – our employees' record of service in times of need continues to be exemplary. Secondly, I wish to thank my predecessor Chair, Tom Woods, for his tireless dedication and steady leadership. Finally, the entire Board of Directors would like to recognize the past leadership of our Acting President and CEO Paul Dobson, who led Hydro One through an important period of transition.

In the coming year Hydro One will remain focused on enhancing shareholder value and on delivering safe, cost-efficient and reliable power to customers. On behalf of the Board of Directors, I appreciate your ongoing trust, confidence and investment in Hydro One.

Timothy Hodgson
Chair of the Board of Directors

Mark Poweska
President & CEO

A Message From Our President & CEO

Since joining the company in May, I have had the opportunity to witness first-hand the expertise and dedication of Hydro One's team members and leadership in carrying out the company's crucial role of delivering the power that drives Ontario's economy and energizes every corner of this province. It is an exciting time to lead this organization and I thank employees and the Board of Directors for the trust they have placed in me as we charted a course for the future of Hydro One.

Over the first weeks and months at Hydro One, I had many discussions to better understand what our customers, investors, stakeholders and Indigenous peoples need and expect from Hydro One.

These conversations, along with a substantial amount of research to understand our customers' priorities, guided the direction of Hydro One's new five-year corporate strategy, which was developed under the direction of our Board of Directors.

Our new strategy outlines five priorities:

- Plan, design, and build a grid for the future
- Be the safest and most efficient utility
- Be a trusted partner
- Advocate for our customers and help them make informed decisions
- Innovate and grow the business

These priorities focus on what really matters to customers, Indigenous peoples, communities, stakeholders and investors: an unwavering commitment to exceptional customer service, safety, efficiency and sustainability. You will find more details on these later in this report.

In 2019, we made good progress on improving Hydro One's financial and operating performance, capturing efficiencies and reducing our operating costs adjusted for Avista related costs by 4.7% during the year.

We improved the reliability of Hydro One's network while focusing on becoming safer, more customer-driven, sustainable and efficient.

Enhancing safety culture, improving safety reporting

We are deeply committed to continually enhancing Hydro One's culture of safety. In March, we tragically lost one of our colleagues who sustained a fatal injury during a forestry incident in the Minden area. While Hydro One's reportable injuries rates have declined in recent years and are considered industry leading, we have seen an increase in serious injuries. This is not acceptable to me and I personally will not rest until we have eliminated serious injuries from our organization.

In 2019, I created a new role on my executive team, a Chief Safety Officer, dedicated to leading our safety program and driving improvements. Our renewed focus on safety includes the introduction of a new, frontline-led Safety Improvement Team to help us determine the actions we need to take to eliminate injuries at Hydro One. We are also making headway on major improvements to our safety reporting and analytics.

Leading emergency response, building resilience

In 2019, we continued to experience storms and weather events, which impacted our customers' families and businesses. Our entire team – including highly trained crews, grid control centre operators and customer service agents – responded to these emergencies and through careful planning, assessed damage and safely restored power in challenging conditions. In 2019, Hydro One employees travelled out of the province to assist Manitoba Hydro when it experienced a severe winter storm with major impacts to its grid. We will always be proud to support our partners in their time of need.

Hydro One is rightly seen as a North American leader in power restoration. In 2019, our leadership was recognized by the Edison Electric Institute (EEI), which presented Hydro One with an Emergency Assistance Award for our response efforts following the deadly California wildfire in 2018; as well as our 10th EEI Award for helping Manitoba Hydro restore power.

Over the next five years, we plan to invest approximately $10 billion in our transmission and distribution systems to ensure a reliable grid for the future. As we make these investments, we will modernize our grid through the introduction of new technologies to prevent outages, increase resiliency, and protect against physical and cyber threats – while allowing us to restore power faster when we experience outages.

As we prepare for more severe storms, we will continue to incorporate considering climate change into our planning to increase resilience and reduce our environmental footprint.

Good neighbour, trusted partner

Our success depends on our ability to build trust as a reliable partner to Indigenous peoples, communities, customers and the many stakeholders we serve across Ontario.

In 2019, we strengthened our ties with Indigenous leaders and communities across the province, increasing our procurement spending to $41.3 million with Indigenous businesses – Hydro One's highest spend ever. In recognition of our work, the Canadian Council for Aboriginal Business selected Hydro One as an Indigenous Procurement Champion. The Canadian Energy Association also recognized us for our efforts in increasing our procurement from Indigenous-owned companies.

In 2019, we completed the Niagara Reinforcement Line (NRL), a new, major transmission project, with our equity partners, the Six Nations of the Grand River Development Corporation, and Mississaugas of the Credit First Nation. This 76-kilometre transmission line was brought to completion by A6N, an Indigenous-owned contractor.

We are also focusing our efforts on partnering with communities and customers to champion economic development opportunities. In southwestern Ontario, we worked with community leaders and customers in Leamington to bring more power to support the region's booming greenhouse sector. We worked collaboratively with the Independent Electricity System Operator to advocate for a new, major transmission line to provide 400 additional megawatts of power, which will have the added benefit of putting downward pressure on electricity rates. We will continue to work closely with our customers to better understand their emerging needs and ensure we have a power grid that continues to support local economic growth.

Through our community investment program, Building Safe Communities, I'm proud to say that we provided training to about 200,000 youth across Ontario to teach them life-saving skills and how to play safe. We also provided 125 donations and sponsorships to over 70 communities across the province.

Exceptional service, reducing costs

Since 2015, Hydro One has been on a journey to serve our customers better and we made great strides in the last year. In 2019, we achieved a score of 85.7% – the highest residential and small business customer satisfaction score in over a decade. We also earned two customer service awards from the Ontario Energy Association. However, we believe we can do better and we will do better.

As the needs and expectations of our customers evolve, we will continue to find ways to introduce new services that meet their needs and make it easier to do business with us.

Our customers not only depend on us to supply reliable electricity, they expect us to run an efficient company and to look for ways to drive costs out of the system.

In 2019, Hydro One achieved productivity savings of $202.3 million and operating cost reductions of $51 million adjusted for Avista related costs. We will continue to focus on improving our efficiency, while never compromising safety.

In 2020, we will continue to be a champion for our customers and the electricity sector in Ontario. We will create a brighter, sustainable future for Ontarians by building strong partnerships, delivering operational excellence and enhancing shareholder value.

Last year we further solidified our executive team by welcoming some industry leaders to Hydro One and through several internal appointments. In 2019, Paul Harricks joined Hydro One as our Chief Legal Officer and we announced David Lebeter would be joining us as our new Chief Operating Officer. Internal appointments included Chris Lopez as Chief Financial Officer, Saylor Millitz-Lee as Chief Human Resources Officer, Brad Bowness as Chief Information Officer and Darlene Bradley as Chief Safety Officer. I have full confidence in this executive team to deliver on our strategic plan over the coming years.

I want to thank all Hydro One employees for their dedication and service this past year and I look forward to what the future holds as together, we build a better and brighter future for all.

Mark Poweska
President & CEO

A Sustainable Future for All

STRONG ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG) PERFORMANCE

50%
Board of Directors diversity (Independent Non Executive)

$1.7 billion
In capital investments to expand electricity grid and renew and modernize existing infrastructure

Selected by the Canadian Council for Aboriginal Business as an Indigenous Procurement Champion

$41.3 million
Total procurement spending with Indigenous businesses – our highest ever spend

104
First Nations communities served by Hydro One Networks Inc. and Hydro One Remote Communities Inc.

$2.8 million
In sponsorships and donations in communities where we live and work

Designated as a Sustainable Electricity Company by the Canadian Electricity Association

Recognized as one of the Best 50 Corporate Citizens in Canada by Corporate Knights

Our Indigenous Partner Network

Hydro One held our first-ever provincial Indigenous Business Fair in downtown Toronto this past September. The event showcased over 40 Indigenous businesses from across the province, and offered Hydro One employees – as well as many of our non-Indigenous business partners – the opportunity to network with these businesses, improve overall awareness of their capabilities, and foster relationships. The Indigenous Business Fair was also a great opportunity for attendees to learn about Hydro One's purchasing needs and showcase Indigenous products, services and solutions; liaise with our lines of business including environment, transmission, distribution, station construction and forestry; and underscore Hydro One's commitment to increase our Indigenous procurement by pursuing mutually beneficial relationships.

A Safer Future for Families

Hydro One and Scouts Canada announced a new partnership to launch Head Safe – a new hands-on program aimed at educating families on the impacts of head injuries, the importance of prevention and safe return to play. Launched in the fall of 2019, with Scouts Canada groups, the program will provide youth, volunteers and families in over 25,000 households with essential educational tools – head injury first aid, how to recognize the early symptoms of a concussion, important safety measures to protect against head injuries and role play on how to respond to real-life scenarios.

Why Invest in Hydro One

1. Everyone Uses Electricity

One of the largest electric utilities in North America with significant scale and leadership position across Canada's most populated province.

2. Strong Balance Sheet

One of the strongest investment grade balance sheets in the North American utility sector.

3. Pure-play Transmission and Distribution

Unique combination of pure-play electric power transmission and local distribution, with no generation or material exposure to commodity prices.

4. Stable Operations

Stable and growing cash flows with 99% of business fully rate-regulated in a constructive, transparent and collaborative regulatory environment.

5. Financial Performance

Predictable self-funding organic growth profile with expanding rate base and strong cash flows, together with broad support for refurbishment of aging infrastructure and with ~5% expected five year rate base CAGR. No external equity required to fund planned growth.

6. Attractive Dividend

Annualized dividend of $0.966 per share with attractive 70% – 80% target payout ratio.

7. Rate Base Expansion

Opportunity for continued dividend growth with rate base expansion, continued consolidation and efficiency realization.

"Our commitment to safety goes beyond the workplace to building safe communities where we live, work and play. Our partnership with Scouts Canada will make a difference by providing young people with the tools and training to prevent and treat head injuries."

Mark Poweska, President & CEO

Our New Corporate Strategy

"Hydro One is a champion for our customers and the electricity sector in Ontario. We are a leader in our sector here in Ontario and across Canada. Our ability to build enduring relationships and strong partnerships is helping us create a brighter, sustainable future for Ontarians. We are steadfast in improving the safety, reliability and environmental performance of our operations. We will remain focused on delivering operational excellence as we drive performance, reduce costs and enhance shareholder value."

Mark Poweska, President & CEO

Enhancing the Value of Hydro One

Hydro One has a responsibility to provide safe, reliable power to Ontarians now and into the future. Our new five year corporate strategy focuses on what really matters to customers, communities, stakeholders and investors an unwavering commitment to safety, exceptional customer service, efficiency and sustainability.

Enabling Success

Successfully executing our strategy will require a people focus that inspires employees and prepares the workforce for our evolving needs; a regulatory focus to support our strategic vision; and a technology focus to enhance the efficiency of our workforce and better enable our customers.

By 2024, our corporate strategy is expected to enhance shareholder value by delivering an improved safety culture, a more reliable grid for our customers, high customer satisfaction, sustainable business practices and a lower environmental footprint.

STRATEGIC PRIORITY	AREAS OF FOCUS
PLAN, DESIGN AND BUILD A GRID FOR THE FUTURE	• Plan, design and build a reliable grid for today and tomorrow and embrace new technology, such as distributed energy resources, to enable customer choice. • Increase focus on grid resilience in order to reduce the frequency and duration of outages. Consider climate change and sustainability factors in our planning to increase resilience and lower our environmental footprint.
BE THE SAFEST AND MOST EFFICIENT UTILITY	• Transform and improve our safety culture through robust safety analytics and grass-roots employee engagement. • Empower field operation teams to drive efficiency, productivity and reliability. • Focus on efficient capital delivery to support our ongoing growing work program.
BE A TRUSTED PARTNER	• Build and grow relationships with Indigenous peoples, government and industry partners. • Proactively address community concerns and establish strong partnerships with our customers through local investment and economic development for the benefit of all Ontarians.
ADVOCATE FOR OUR CUSTOMERS AND HELP THEM MAKE INFORMED DECISIONS	• Enrich the customer experience by acting as their trusted energy advisor, helping them save money, and offering new products and services to meet their energy needs. • Help our customers make informed decisions with deeper insights and leverage our position as energy experts.
INNOVATE AND GROW THE BUSINESS	• Invest responsibly in our core transmission and distribution business. • Pursue incremental regulated and unregulated business opportunities through innovation and our focused presence in Ontario.

Plan, Design and Build a Grid for the Future

We will plan, build and design a grid that meets the needs of Ontarians today and into the future. This means improving reliability by investing in technology that will allow us to modernize our grid. Sustainability is also central to our strategy. As we prepare for more severe storms, we will consider climate change in our planning to increase resilience and lower our environmental footprint.

Our Focus

We are pursuing various strategic initiatives to build a grid for our customers that is reliable, resilient and flexible while balancing our environmental responsibility in pursuit of these goals:

- **Planning, designing and building a reliable grid for the future:** Providing safe and reliable power to customers is our top priority. We will continue to invest in our existing infrastructure to maintain a reliable and resilient grid, while embracing new technology for tomorrow.
- **Increasing grid resiliency and sustainability to quickly recover from events:** We will continue to automate the grid and deploy NextGen solutions to ensure the grid can withstand more extreme storms and weather events. We will focus on installing technologies that improve outage response times and minimize impacts.
- **Improving grid flexibility to integrate and operate Distributed Energy Resources (DERs) enabling customer choice:** We will incorporate distributed energy resources to enable customer choice while delivering exceptional value to customers through best-in-class asset management practices.
- **Reducing our environmental footprint:** Hydro One strives to continue reducing greenhouse (GHG) emissions as a part of its commitment to environmental, social, and corporate governance (ESG).
- **Delivering value through great planning:** A robust and efficient planning process ensures the prudent use of every dollar entrusted to us, whether for capital investments or operations.

Our Performance

In 2019, we improved the overall reliability of our distribution network, while also improving restoration times. Contributing to this performance was $1.2 billion in expenditures to expand our distribution grid and renew and modernize existing infrastructure, as well as the positive impact of our new storm prediction tools and vegetation management program. Hydro One's Customer Average Interruption Duration Index (CAIDI), a key measure of success in delivering reliable power, improved by 9.7% in 2019 from 2018.

We continued to invest in technology to improve grid resiliency and to modernize cybersecurity protection of our core assets – important not only for Ontario's economy, but for other provinces and the United States with whom we share North America's interconnected grid system. As part of our Distribution Modernization program, we installed 1,188 devices to better determine the location of a fault on the distribution

HELPING OUR COMMUNITIES RECOVER QUICKLY FROM STORMS

Our new storm prediction tool allows us to take a proactive approach to preparing for bad weather by positioning our crews and equipment in areas expected to be the most impacted by storms. Our leadership in power restoration recently earned us our 10th EEI Emergency Assistance Award for helping Manitoba Hydro restore power after a severe snowstorm hit the province in October 2019.

system and quickly dispatch a crew to repair it, as well as to remotely isolate the problem and restore power in some cases. We also continued to build our Distributed Energy Resource Management System (DERMs), which is a technology that enables real-time control of generation and load on the system. In addition, we lowered our environmental footprint by continuing to green and rationalize our fleet of approximately 7,000 vehicles.

Our Future

In 2020, we will focus on efficiently deploying capital to meet Ontario's needs while reducing customer service interruptions; make incremental investments to modernize, harden and protect our assets; and develop and implement a GHG emissions reduction plan.

Our grid is critical to powering Ontario and the broader Canadian economy. It is our responsibility to plan for the future, to ensure the delivery of reliable and safe power in the years to come.

2019 Highlights

17.4%[1]

SAIDI (System Average Interruption Duration Index) for Transmission improvement in 2019 over 2018

16.7%[2]

SAIFI (System Average Interruption Frequency Index) for Transmission improvement in 2019 over 2018

9.7%

CAIDI improvement in 2019 over 2018

1,2. 2018 figure excludes the impact of the Ottawa tornado

Be the Safest and Most Efficient Utility

Safety is a core value at Hydro One and something to which we are deeply committed. Each one of our employees must go home safely after a fulfilling day of work. We believe that a safe utility is an efficient utility and that a healthy safety culture fosters accountability and discipline across all aspects of our business.

Our Focus

We are pursuing a number of strategic initiatives to engage with employees in driving productivity, reliability and efficiency, while eliminating on-the-job injuries:

- **Transforming and improving our safety culture:** In a healthy safety culture, there is a high-degree of accountability across every level of the organization. Through discipline and grassroots employee engagement, we will improve our safety culture and increase safety reporting and accountability.
- **Enabling field operations to drive productivity and reliability:** We firmly believe in continuous improvement to enhance the efficiency, productivity, and reliability of our field operations. People are most productive when they are empowered with the right tools and the right work in a safe environment free from unnecessary burden.
- **Optimizing corporate support:** New ways of thinking and working, both traditional approaches and digital capabilities, will help us create efficiencies in our corporate support functions. We are exploring everything from centralizing functions and employing lean process improvements, to automating business processes and analytics-enabled decision-making.
- **Driving efficient capital delivery:** We are building an efficient end-to-end capital process to ensure we can deliver on our work program to build a safe and reliable grid for our customers. Rigorous capital planning and execution are key to successfully delivering efficient capital on behalf of all stakeholders.

Our Performance

In March 2019, we experienced a tragic loss when a Hydro One employee sustained a fatal injury during a forestry incident in the Minden area. The memory of our lost colleague only strengthens our commitment to an injury-free workplace. We have appointed Darlene Bradley to the newly created role of Chief Safety Officer to lead the transformation of our safety culture. She has established a Safety Improvement Team, comprised of a diverse cross-section of employees, which is dedicated to eliminating incidents from the workplace that result in injuries.

We purchased four electric vehicles (EVs) during 2019 and are on track to purchase 16 more EVs in 2020. As we continue to green out fleet, we are planning on converting 50% of our fleet of sedans and SUVs to electric vehicles or hybrids by 2025. Additionally, we continued to optimize our fleet, leveraging GPS fleet tracking to more efficiently deploy and manage our vehicles on the road, support safer and more energy-efficient driver behaviour and reduce fuel and maintenance costs, while also extending the life of Hydro One vehicles. These measures helped us achieve $29 million in fleet productivity savings.

Approximately 500 members of our forestry team began using mobile tablets in the field to efficiently plan their work and to realize the full potential of our vegetation

MAKING THINGS BETTER FOR OUR CUSTOMERS AND COMMUNITIES

Our state of the art vegetation management program (OCP) has been welcomed by our customers and community partners alike, while delivering major efficiencies and savings. With a three year maintenance cycle, OCP trims problem trees and vegetation more often to improve the overall safety and reliability of the system. In 2019 our forestry teams completed approximately 31,600 kilometres of work along power lines – with the volume of trees managed at an all time high. But perhaps the biggest benefit is that OCP has proved to be less disruptive to our community stakeholders, removing less vegetation while being more aesthetically pleasing; being better for the environment with less bio disruption; creating less noise and improving overall reliability for our customers.

management program – Optimal Cycle Protocol (OCP). In support of our growing capital work programs, we partnered with contractors to improve the predictability of our project pipeline, with more upfront focus on risk assessment and project planning.

We continued to optimize our shared services portfolio – which includes our supply chain and real estate functions – pursuing opportunities to monetize our land holdings and continue to increase efficiencies in procurement of materials and services.

Our Future

In 2020, we plan to develop an integrated reporting system that accounts for near misses; a safety analytics program to gain better insight into safety incidents and mitigate future incidents; and enhance our process to ensure effective response to safety investigation reporting. We will also empower our field operators to focus on the work that matters and streamline their activities in order to improve overall grid reliability.

"Safety is good for business. A company that's more careful, systematic and driven by proven, repeatable processes will lead to being a better-managed and more efficient business."

Mark Poweska, President & CEO

2019 Highlights

29.6%

Total Annual Recordable Injury Rate improvement in 2019 over 2018

49.3%

Increase in annual total productivity savings (capital and OM&A) in 2019 over 2018

Be a Trusted Partner

Hydro One will be a trusted partner to Indigenous peoples, industry stakeholders, government, communities, customers and all Ontarians. Our goal is to build and grow relationships to deliver greater value for our customers and shareholders.

Our Focus

We are pursuing various strategic initiatives to foster trust and improve relationships with our key partners:

- **Growing relationships with government and industry partners:** We want to enhance our relationships with industry and government and to advocate for our customers on matters of affordability and innovation. As a trusted leader in the energy sector, we will continue to advance energy-related innovations and policies that benefit all Ontarians.
- **Building strong partnerships with Indigenous peoples:** We are committed to building respectful and positive relationships with Indigenous communities. We firmly believe that this proactive approach will benefit all communities, as well as enable growth across the province.
- **Building trust with customers, communities, and all Ontarians:** We are committed to serving all Ontarians – now and into the future. Our shared success depends on our ability to build trust as a reliable partner and good neighbour.

Our Performance

We consulted with the government on the modernization of the Ontario Energy Board (OEB), advocating for structure and system reforms that will reduce red tape while improving overall transparency, the efficient delivery of capital and the environmental assessment process. We also advocated with government on behalf of our customers and advanced a number of critical transmission projects during the year, including the Leamington Area Transmission project.

In recent years the greenhouse industry in southwestern Ontario has been booming in and around Leamington. We heard from local government and business leaders that this community needed significantly more power to support the growth it was experiencing. Through a collaborative process, we worked together with the IESO and local community leaders to understand needs in the area so that new infrastructure could be built to support the growing demand for electricity. This work together was a success: in June of this year the IESO directed us to build a new transmission line from Chatham to Lakeshore, to support growing demand for electricity in this area.

We advanced various procurement and employment opportunities with the 104 First Nations communities served by Hydro One Networks Inc. and Hydro One Remote Communities Inc. In 2019, we increased our procurement spending with Indigenous businesses by 4.8% over 2018 to $41.3 million – our highest ever annual spend. We held our first Hydro One Indigenous Fair as well as nine Indigenous procurement workshops. In recognition of our outreach, the Canadian Council for Aboriginal Business selected Hydro One as an Indigenous Procurement Champion.

At the community level, we proudly returned as a presenting sponsor of the 2019 Little Native Hockey League tournament – an annual gathering that brings together over 2,500 competitors from Indigenous communities across Ontario to compete in a

safe environment. With our partner Indspire we awarded Leonard S. (Tony) Mandamin Scholarships to 20 Indigenous students enrolled in electricity-related programs at colleges and universities across Ontario, who also have the opportunity to apply for paid work placements with Hydro One.

Through our community investment program, Building Safe Communities, Hydro One provided training to about 200,000 youth across Ontario to teach them life-saving skills and how to play safe. We also provided 125 donations and sponsorships to over 70 communities across the province.

Our Future

We will continue to implement our multi-year Indigenous hiring plan and to develop a comprehensive Indigenous community engagement plan for guiding Indigenous equity partnerships, procurement and employment opportunities.

SUPPORTING LONG TERM ECONOMIC OPPORTUNITIES FOR FIRST NATIONS COMMUNITIES

Hydro One operates on traditional territories and as such, we have a responsibility to grow the Indigenous economy while building meaningful relationships based on mutual respect. In 2019 Hydro One completed a major transmission project, the Niagara Reinforcement Line, with two First Nations equity partners, Mississaugas of the Credit First Nation and Six Nations of the Grand River Development Corporation, a community owned corporation of the Six Nations of the Grand River First Nation. This 76 kilometre transmission line was brought to completion by A6N, an Indigenous owned contractor, and placed in service in August 2019. This partnership model enables the delivery of critical infrastructure that delivers economic value to the people of Ontario, while ensuring key benefits flow to local First Nation communities such as overall capacity building, along with direct and indirect job opportunities. "The Niagara Reinforcement Line will not only generate millions of dollars of benefit for the Six Nations community, it s also a step forward for Indigenous participation in the economy," said Matt Jamieson, President and Chief Executive Officer, Six Nations of the Grand River Development Corporation. We have proven our ability to partner and have demonstrated unprecedented capacity to leverage our skilled labour to drive economic development, not only within our community, but across Ontario."

2019 Highlights

$41.3 million

Indigenous procurement Hydro One's highest ever spend

104

First Nations communities served by Hydro One Networks Inc. and Hydro One Remote Communities Inc.

Advocate for Our Customers

The electricity industry is evolving and so are the needs of our customers. We will continue to advocate for our customers and help them make informed decisions. To enrich the customer experience, we will build and enhance our digital capabilities and offer new products and services to meet their energy needs.

Our Focus

We are pursuing key strategic initiatives to improve the customer experience and enhance customer satisfaction:

- **Making it easier to do business with Hydro One:** More and more, customers are relying on mobile technology and self-service options to simplify their lives and improve their customer experience. We are expanding our use of digital tools and channels to ensure we remain a trusted and cost competitive business partner for our customers.
- **Helping customers make informed decisions:** As their trusted energy resource, Hydro One is committed to providing its customers with deeper insights and tailored solutions for their energy needs. We also help our customers by advocating for them to meet their needs by offering a fresh perspective on the most efficient and reliable solutions the market offers.
- **Being our customers' provider of choice:** Our residential, small business, and commercial/industrial customers are increasingly concerned about affordability, reliability, and power quality. As a large electric utility, we are uniquely positioned to expand their access to third-party products and services.

Our Performance

In 2019, we achieved a residential and small business customer satisfaction score of 85.7% – our highest in over a decade. The increase can be attributed to: improved customer experience, reliability, rates, and the strength of the Hydro One brand. Transmission customer satisfaction was 87.2%, reflecting a new approach to the delivery of customer service to this customer group. During the year, we increased the number of new connections for our distribution customers, responding to high volumes and requests for more load, bringing a second transmission station into service in Leamington. Capping the year, Hydro One earned two customer service awards from the Ontario Energy Association (OEA) – the 2019 OEA Customer Service Award to the Hydro One Networks Inc. Business Customer Service Team and the 2019 OEA Contributor Award to Ryan Boudreau, our Manager of Protection and Automation.

We are continuing to make it easier to do business with us by modernizing our Customer Contact Centre and launching a dedicated web portal for our commercial and industrial customers, improving their ability to access and manage their usage and billing information. Digital technology is helping us deliver more effectively on key customer interactions. We have enrolled approximately 500,000 customers for proactive outage alerts, allowing them to stay informed with the latest information during outages, providing convenience for customers.

CONNECTING OUR CUSTOMERS WITH REAL TIME INFORMATION

In February, we updated Hydro One s new customer Outage Map and App, which includes advanced features, such as a weather radar and street level detail. We know our customers need real time information when the lights go out and our new Outage Map will make it easier to get the latest information while our crews work to get the power back on," said Imran Merali, Vice President of Customer Service, Hydro One. The Outage Map now provides customers with enhanced features to track outages in Hydro One s service area along with the ability to bookmark multiple locations for easy reference. Other new features include: the ability to view outage information for individual homes, cottages or businesses; a weather radar overlay that allows customers to view current weather; updates every 10 minutes as information comes in from crews on site; and improvements to be compliant with AODA (Accessibility for Ontarians with Disabilities).

In March, we hosted an energy conference for our large industrial customers, helping them keep pace with changes in the province's energy landscape. Our dedicated account managers continued to provide these customers with detailed information on their consumption patterns, while we continued to advocate for their needs and provide guidance on the most efficient and reliable solutions the market offers.

Our Future

We will explore opportunities for building access to third-party services for residential customers and creating offerings customized to our commercial and industrial customers' needs, while providing commercial and industrial customers with the tools and technology they need to make informed decisions.

Hydro One is on a multi-year journey to transform the customer experience by creating digital channels that enhance existing services, introduce new services, and offer innovative solutions to better anticipate and meet the needs of customers.

2019 Highlights

85.7%

Residential and small business customer satisfaction

87.2%

Transmission customer satisfaction

90.0%

Hydro One Telecom Inc. customer satisfaction

Innovate and Grow the Business

Growth and innovation are central to providing value for our customers and our shareholders. With change comes opportunity and Hydro One will innovate to compete in our evolving marketplace. While we will continue to invest responsibly in our core transmission and distribution business, we will pursue regulated and unregulated business opportunities in Ontario.

Our Focus

We are pursuing various strategic initiatives to drive the sustainable financial growth of our business and provide innovate offerings to our customers:

- **Responsibly investing in rate base assets:** We will continue to invest responsibly in our core transmission and distribution business to ensure grid safety, efficiency and reliability – and to deliver the services our customers depend on for their electricity needs. With many transmission and distribution assets aging and degrading, investment in grid modernization remains critical to the long-term health of the system.
- **Pursuing new regulated opportunities:** We plan to actively pursue growth opportunities in the regulated portion of our business that can benefit ratepayers and shareholders alike – through acquisitions of local distribution companies (LDCs) and competitive transmission projects within Ontario. Ontario currently has 58 LDCs, making this a significant opportunity to find efficiencies to drive costs out of the system.
- **Pursuing innovative unregulated opportunities:** Unregulated opportunities are critical to ensuring our long-term sustained growth in an evolving market. We will pursue these growth opportunities in order to diversify our portfolio and respond to the changing needs of the market, as well as to foster a culture of entrepreneurship and innovation at Hydro One.

Our Performance

In 2019, we invested approximately $1.7 billion to expand the electricity grid and renew and modernize existing infrastructure – $624 million in our distribution business and $1 billion in our transmission business. Some of the largest transmission capital additions included: $73 million on the replacement of transmission line insulators and $40 million on the replacement of transmission line wood poles across the province; $28 million each on the new Leamington TS #2 (transmission station) and the rebuild of Hanmer TS in northeastern Ontario; $27 million to refurbish Bronte TS in the western GTA; $26 million on the refurbishment of the D2L circuit in northeastern Ontario; $26 million to build the new Enfield TS in the Durham region; $25 million as part of a project to rebuild one of the switchyards serving Bruce Power's nuclear generating stations; and finally, $119 million in capital additions with the completion of the Niagara Reinforcement Line. We continued to focus on replacing aging priority assets using a disciplined approach to capital investments, with a goal to deliver greater value for both our customers and shareholders.

We pursued new regulated opportunities, mainly through the ongoing consolidation of Ontario's electricity distributors. Hydro One remains committed to its

HYDRO ONE TELECOM INC. TRUSTED ENTERPRISE BUSINESS PARTNER

In 2019, HOT began pivoting from a focus of providing businesses with commoditized fibre connectivity to offering a suite of value added services to meet customers connectivity and data management needs. These new services complement Hydro One Telecom Inc. s province wide fibre optic network and include an expansion of connectivity options with Secure SD WAN, as well as cloud based offerings of Backup as a Service (BaaS) and Infrastructure as a Service (IaaS). HOT now provides an enhanced suite of cloud services, data backup tools and secure data storage options for our customers to choose from, ultimately providing managed services and adding to net income growth.

$105-million purchase of Peterborough's electrical utility, pending approval from the Ontario Energy Board. We also continued to move through the regulatory process to acquire Orillia Power Distribution Corp – a $41.3-million purchase, which is expected to bring long-term economic value to businesses and residents in Simcoe County. Additionally, we announced an investment of approximately $150 million to build a state-of-the-art grid control centre in Orillia, which will serve as one of our innovative technology hubs and will ensure the safe, reliable delivery of electricity to communities across all of Ontario for years to come.

Our pursuit of unregulated growth opportunities is mainly through our telecom subsidiary. With approximately 9,000 route kilometers in fiber optic lines, HOT is seeking to expand on its success, as well as to identify new opportunities for innovative growth within Ontario.

We have entered into a partnership with Ontario Power Generation to provide an easier charging experience for Ontario's EV drivers. By the end of 2021, the Ivy Charging Network is expected to have 73 fast-charger stations across Ontario.

Our Future

In 2020, we plan to invest approximately $1.9 billion in our rate base assets while pursuing opportunities to participate in competitive processes for pursuing LDCs and transmission lines within Ontario. We also plan to accelerate the growth of the telecom business.

Highlights

7.3%

Adjusted EPS CAGR since IPO

$10.1 billion

In regulated capital investments in the next 5 years

Corporate Governance

Strong corporate governance practices are at 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 ensures 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 maintaining best corporate governance practices. 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 the Province of Ontario.

To learn more about the Directors, committee mandates and composition, go to **www.HydroOne.com/Investors**

Board of Directors and Committees (as at January 1, 2020)

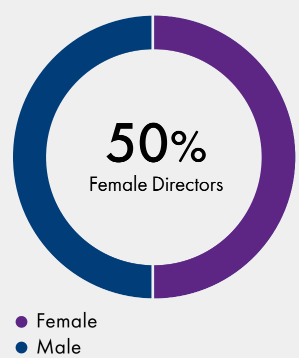
Committees	Audit	Governance	Human Resources	Health, Safety, Environmental and Indigenous Peoples
Timonthy Hodgson (Chair)				
Mark Poweska (President & CEO)				
Cherie Brant		•		•
Blair Cowper-Smith		★	•	
Anne Giardini	•			★
David Hay	•			•
Jessica McDonald	•		•	
Russel Robertson	★		•	
William Sheffield	•			•
Melissa Sonberg		•	★	
Susan Wolburgh Jenah[2]	Pending Appointment			

★ Chair • Committee Member

Hydro One's Progressive, Gender-Diverse and Independent Board of Directors

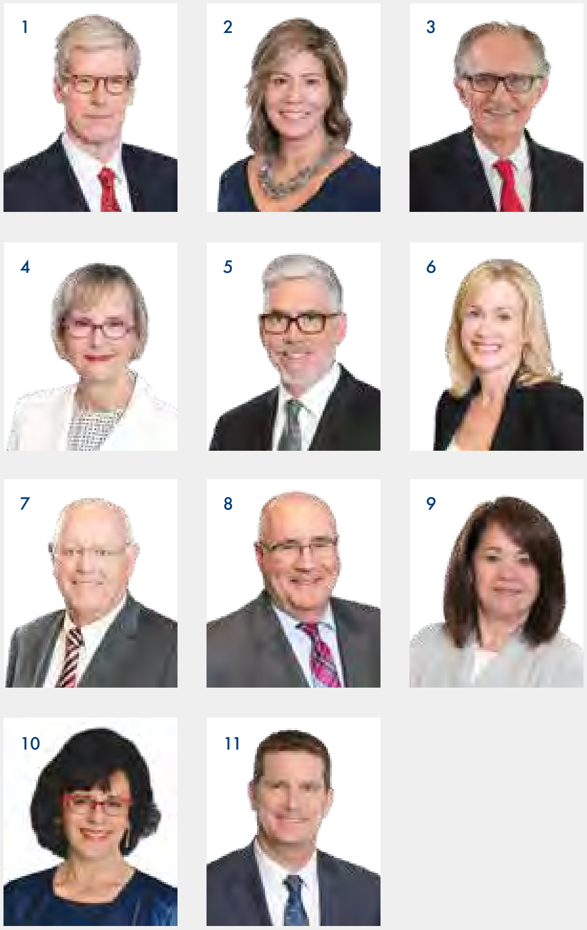
We value diversity at all levels of Hydro One and its commitment extends to ensuring a gender-diverse Board of Directors. With the announcement of Susan Wolburgh Jenah in 2019, the composition of our Independent Non-Executive Board is five women (50%) and five men (50%), making us one of the most gender progressive boards in North America. It also reflects best practices in board diversity and surpasses our Catalyst Accord commitment to maintaining at least 30% female board members. The Catalyst Accord is a global non-profit organization dedicated to gender parity in the workplace.

Board Gender Diversity[1]



1. Hydro One's Independent Non-Executive Board of Directors
2. Became a director on January 1, 2020

Board of Directors



1. **Timothy Hodgson**, MBA, FCPA, ICD.D
Corporate Director, Chair of Hydro One Ltd, Chair of Sagicor Financial Corporation Limited, Director Public Sector Pension Investment Board (PSP Investments), Director Alignvest Acquisition II Corporation, retired Managing Partner Alignvest Management Corporation, Former Special Advisor to Bank of Canada Governor Mark Carney, Former CEO Goldman Sachs Canada

2. **Cherie Brant**, JD
Partner, Borden Ladner Gervais LLP, Director Anishnawbe Health Foundation, Member Canadian Council for Aboriginal Business, Research Advisory Board, Aboriginal Energy Working Group-IESO

3. **Blair Cowper-Smith**, LLM, ICD.D
Principal and founder Erin Park Business Solutions, Former Chief Corporate Affairs Officer OMERS

4. **Anne Giardini**, O.C., O.B.C, Q.C, LLM
Chancellor, Simon Fraser University, Former Canadian President Weyerhaeuser Company Limited, Former Director Nevsun Resources LTD

5. **David Hay**, LLB, ICD.D
Managing Director Delgatie Incorporated, Former CEO New Brunswick Power Corporation, Former Vice-Chair and Managing Director of CIBC World Markets Inc., Director EPCOR, Council Member of the Council for Clean and Reliable Energy

6. **Jessica McDonald**, ICD.D
Corporate Director, Chair, Canada Post Corporation, Former President & CEO BC Hydro & Power Authority, Director Coeur Mining Inc., Chair Trevali Mining Corporation, Member Council of Sustainable Development Technology Canada

7. **Russel Robertson**, FCPA, FCA, ICD.D
Corporate Director, Former EVP and Head, Anti-Money Laundering, BMO Financial Group, Former Vice-Chair, Deloitte & Touche LLP, Director Bausch Health Companies Inc., Director Turquoise Hill Resources

8. **William Sheffield**, BSC, MBA, ICD.D
Corporate Director, Former CEO Sappi Fine Papers, Director Houston Wire & Cable Company, Director Velan Inc., Former Board Member OPG

9. **Melissa Sonberg**, BSC, MHA, ICD.D
Adjunct Professor and Executive-in-Residence, McGill University, Desautel Faculty of Management, Director Exchange Income Corporation, Former Senior Vice President, Human Resources & Corporate Affairs and Senior Vice President, Global Brands, Communications and External Affairs at AIMIA

10. **Susan Wolburgh Jenah J.D.**, ICD.D
Corporate Director, Director Laurentian Bank, Director Aecon Group Inc, and Humber River Hospital. Governor of the Financial Industry Regulatory Authority (FINRA), and member of the Independent Review Committee of Vanguard Investments Canada

11. **Mark Poweska**, President and CEO of Hydro One Ltd, Former Executive Vice President, Operations at BC Hydro, Director and Chair of the Operations Committee of the Western Energy Institute, Board Advisor to Yukon Energy Corporation

Executive Leadership Team

11. **Mark Poweska**
President and Chief Executive Officer

12. **Brad Bowness**
Chief Information Officer

13. **Darlene Bradley**
Chief Safety Officer

14. **Jason Fitzsimmons**
Chief Corporate Affairs & Customer Care Officer

15. **Paul Harricks**
Chief Legal Officer

16. **David Lebeter**
Chief Operating Officer, January 2020

17. **Chris Lopez**
Chief Financial Officer

18. **Saylor Millitz-Lee**
Chief Human Resources Officer

For detailed biographical information of Hydro One Limited Board members, go to www.HydroOne.com/Investors.

The biographical information of Hydro One Limited Board members is based on information available to management as of January 15, 2020.

Building a better and brighter future

2020 Annual Report

Corporate Profile

Hydro One Limited (TSX: H) through its wholly-owned subsidiaries, is Ontario's largest electricity transmission and distribution provider with approximately 1.4 million valued customers, approximately $30.3 billion in assets as of December 31, 2020, and annual revenues in 2020 of approximately $7.3 billion.

Our team of approximately 8,700 skilled and dedicated employees proudly build and maintain a safe and reliable electricity system which is essential to energizing life in communities across the province. In 2020, Hydro One invested approximately $1.9 billion in its transmission and distribution networks and supported the economy through buying approximately $1.7 billion of goods and services. We are committed to the communities where we live and work through community investment, sustainability and diversity initiatives. We are designated as a Sustainable Electricity Company by the Canadian Electricity Association. Hydro One Limited's common shares are listed on the TSX and certain of Hydro One Inc.'s medium term notes are listed on the NYSE. Additional information can be accessed at www.hydroone.com; www.sedar.com or www.sec.gov.

Contents

1

Higher Customer Satisfaction

Our focus on customers and customer advocacy helped achieve high customer satisfaction scores, with residential and small business customer satisfaction increasing to 87% from 86%, and Hydro One Telecom customer satisfaction increasing to 91% from 90%.

6

Reducing Costs

A 9.4% or approximately $111 million reduction in annual operating costs since 2019.

2020 Highlights

Guided by our purpose of energizing life in Ontario, we are living up to our deep responsibility to put people first as we navigate COVID 19. Throughout the pandemic, our decisions and actions were continuously guided by two priorities – protecting our employees and maintaining the safe and reliable supply of electricity to our valued customers.

2

Stronger Safety Culture

We launched our Safety Improvement Team, which made concrete recommendations to improve the safety culture of our organization to eliminate serious injuries at Hydro One. We will put these recommendations to work in the coming years.

3

Standing Up for Communities

Our community partnerships supported Ontarians through the pandemic, helping local and Indigenous communities respond to emerging and urgent needs for critical food, medical, safety and other supplies.

4

Reliable Electricity Supply

We improved the System Average Interruption Duration Index (SAIDI) of our transmission network by approximately 41.8%[1] over 2019, successfully delivering reliable power to our electricity utility customers.

5

More Productivity Savings

A 41.4% increase in year-over-year productivity savings with $286.0 million saved in 2020 as compared to $202.3 million in 2019. Total productivity savings since 2015 amount to $738 million.

7

Critical Capital Investments

We invested approximately $1.9 billion in capital to expand the electricity grid and renew and modernize existing infrastructure.

8

Sustainability Leadership

Our sustainability progress was again recognized by our peers, with Corporate Knights ranking us 11th in its annual list of Best 50 Canadian Corporate Citizens and the Canadian Electricity Association re-designating Hydro One as a Sustainable Electricity Company.

9

Progressive Aboriginal Relations

We increased total procurement spending with Indigenous businesses to $42.0 million, our highest spend to date. In addition, the Canadian Council for Aboriginal Business advanced Hydro One to Silver level certification in Progressive Aboriginal Relations from our Bronze level in 2017.

10

Best Employer, 6th Year

For the sixth consecutive year, Hydro One has been recognized by Forbes in its list of Canada's Best Employers for 2021, reflecting our commitment to creating a diverse, inclusive and engaged workforce, both during these unprecedented times and into the future.

[1] Transmission SAIDI for multi circuit supplied delivery points

A message from our

Chair

I am incredibly proud of the resilience employees have shown this past year, doing everything possible to maintain the critical supply of electricity to customers across the province – keeping loved ones safe, hospitals running, protecting the most vulnerable in communities, and providing financial relief across Ontario.

18.5%
total shareholder return in 2020

50%
women on our Independent Non-Executive Board Members

This effort required strong leadership and a focused strategy as the COVID-19 pandemic fundamentally changed how we live and work. I know Mark and his team will retain the insights gained from the pandemic to help Ontario emerge stronger, as we work together to create a better and brighter future for all.

Our primary focus at the Board level has been to support Hydro One's executive team, ensuring they have the tools and capacity to achieve our two pandemic priorities – to protect our employees and to maintain the safe and reliable supply of electricity to Hydro One customers.

They have successfully delivered on these priorities, while simultaneously executing our corporate strategy and capital investment commitments. As a result, Hydro One added 18.5% in total returns to our shareholders and acquired the Orillia Power Distribution Corporation and the business and assets of Peterborough Distribution Inc. this past year.

Equally important in this time of great need, Hydro One has stood with our communities and charitable organizations across Ontario to respond to the urgent challenges presented by COVID-19, lending a helping hand to those making a lasting difference in the communities we serve.

As we move forward into the future, we will continue to fulfill our mission of energizing life for people and communities through a network built for the possibilities of tomorrow.

Our corporate strategy supports that mission, driving us to deliver an improved safety culture, a more reliable grid for our customers, high customer satisfaction, sustainable business practices and a lower environmental footprint.

In 2020, the Board revamped the structure and mandates of its committees to support Hydro One's new corporate strategy and further embed our vision across the organization. We established the Indigenous Peoples, Safety & Operations Committee[1] in order to elevate the importance of improving our safety culture and strengthening our partnerships with First Nations. We also elevated the review of Hydro One's annual sustainability report to the full Board, underscoring the improved transparency and accountability of our environmental, social and governance (ESG) disclosures. Finally, we recognized the importance of regulatory and public policy matters within the electricity sector by expanding our Governance & Regulatory Committee.[2]

[1] Previously the Health, Safety, Environment and Indigenous Peoples Committee
[2] Previously the Governance Committee

The Board met virtually and frequently throughout 2020 to ensure Mark and his team had the support they needed to execute Hydro One's corporate strategy and achieve our pandemic priorities. Technology allowed more people from more places to participate virtually in our annual general meeting. While we anticipate hosting a virtual AGM in 2021, we look forward to hosting our next in person gathering.

Throughout the pandemic, the Board has deepened our level of engagement with Hydro One stakeholders. We have been extremely supportive of Hydro One's Pandemic Relief Program, established in mid-March to assist customers affected by COVID. We applaud management for pledging its support for the anti-racism BlackNorth Initiative, as well as to Indigenous Peoples and People of Colour. We will continue to collectively work toward ending systemic racism and ensuring our organization reflects the communities we serve.

We welcomed Stacey Mowbray to the Board of Directors in July, who brings extensive CEO and public company board experience. Her strong track record in leading successful and high profile publicly traded consumer brands reinforces our Board and reaffirms our support of management's focus on delivering exceptional customer service in the digital age. The Board thanks Anne Giardini for her service and for spearheading our First Nations partnership strategy and our renewed commitment to safety. Our Independent Non-Executive Board Members remain composed of 50% women and 50% men, again reflecting best practices in board diversity and surpassing our Catalyst Accord commitment.

On behalf of my Board colleagues and all Hydro One stakeholders, I would like to thank Mark and his executive team for their steady leadership in these uncertain times. We also want to recognize the resilience and dedication of Hydro One's 8,700 employees, particularly those on the frontlines who continued to support our customers and communities across the province. Together, we are confident that Hydro One will continue to energize life for families, businesses and communities across Ontario.

T Hodgson

Timothy Hodgson
Chair

"As we move forward into the future, we will continue to fulfill our mission of energizing life for people and communities through a network built for the possibilities of tomorrow."

A message from our

President & CEO

Power is a lifeline connecting families, businesses and communities, especially during times of crisis. During this historic moment governments, companies, and individuals are being evaluated for their commitment to helping people and communities, standing up for equity and inclusion, and contributing to a more sustainable world.

We have stood by our customers, providing financial relief and flexibility during a period of great uncertainty. Hydro One was the first utility in Ontario to launch a Pandemic Relief Program, supporting customers experiencing hardship with financial assistance and increased payment flexibility. We also extended our Winter Relief Program to ensure our customers remained connected, suspended late fees for all customers, and returned approximately $5 million in security deposits to more than 4,000 businesses across the province. We will continue to put the needs of customers and communities first, advocating on their behalf to provide relief, flexibility and choice, now and in the future.

Our employees are our greatest asset and through their passion, determination and ingenuity, we came together, dug deep and emerged from 2020 even stronger. We have kept our colleagues and workplaces safe, and maintained the critical supply of electricity to the benefit of all Ontarians.

Hydro One achieved strong performance despite facing unprecedented challenges – we strengthened our customer advocacy, deepened our community partnerships, and increased our productivity savings by 41.4%, while never losing our focus on safety.

Hydro One teams worked around the clock to ensure an uninterrupted supply of power for every Ontarian – proactively patrolling power lines that feed hospitals, health care facilities and other critical infrastructure, prioritizing projects that enable our food supply, and connecting new homes to ensure people have shelter.

Living Our Strategy

More than simply aspirational words on paper, our new corporate strategy, along with our vision and mission, have been our guidepost in navigating our way through the pandemic. It has anchored us to our purpose, while providing us with the flexibility to quickly respond to evolving stakeholder needs. Despite a pause in our operations early in the pandemic to introduce new practices to ensure the safety of our crews on the front lines, we successfully executed Hydro One's 2020 workplan. This is not only vital to ensuring system safety and reliability for today, but also for longer-term work that will help restart and sustain the economy in the future.

Build a Grid for the Future: In 2020, we continued to invest in the reliability and performance of our transmission and distribution systems, renew aging infrastructure, connect new load customers and generation sources, and improve our service to customers. We made capital investments of approximately $1.9 billion, placed approximately $1.6 billion in projects into service and supported the economy through buying approximately $1.7 billion of goods and services.

While our restoration times were impacted by challenging weather, and the pandemic, we were still able to improve our transmission reliability and maintain the frequency of customer interruptions on our distribution network.

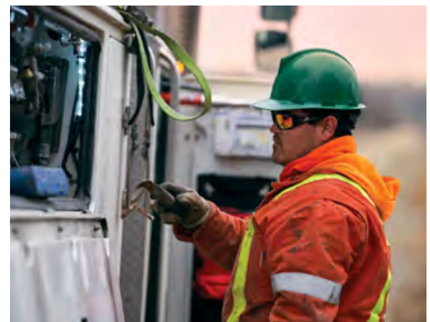
We continue to invest in infrastructure and technology to build a sustainable grid for the future – investments that harden and protect our assets against the changing climate. As part of our ESG commitments, we are working to align our climate-related disclosures with the Taskforce on Climate-related Financial Disclosures, reduce our carbon footprint, and manage the impacts of climate change on our business. For example, we remain on track to convert 50% of our fleet of sedans and SUVs to electric vehicles or hybrids by 2025 in order to reduce carbon emissions.

Safety & Efficiency: Protecting the health and safety of our employees has been our top priority throughout the pandemic. While we were successful in minimizing the impact of the pandemic on our employees, our success is muted because we sadly lost an employee during the year to a motor vehicle crash. Our entire executive team will continue to focus on transforming our safety culture and implement the concrete recommendations made by our Safety Improvement Team to improve our safety culture and eliminate serious injuries at Hydro One.

In 2020, we continued to engage with employees on transforming work processes to drive productivity, reliability and efficiency. Through this work and other initiatives, we achieved $286.0 million in annual total productivity savings and reduced our operating costs by approximately $111 million.

Trusted Partner: We continued to strengthen our community and Indigenous partnerships in 2020. We contributed $42 million to the Indigenous economy by sourcing goods and services from Indigenous businesses – this represents the highest spend to date. We also launched a new fund to support those who provide services to Ontarians, helping to strengthen community resiliency and safety.

Our ability to problem-solve and be nimble would not have been possible without the devotion and hard work of our employees and the partnership of our unions. We were pleased that despite COVID-19, we were able to renew two collective agreements with the Power Workers' Union, covering a large sector of our employees, which will be critical to our journey toward zero serious injuries.



$1.7b
supported economy by buying goods and services

$286m
in annual total productivity savings in 2020

41.4%
increase in annual total productivity savings (capital and OM&A) in 2020 over 2019

$111m
in reduced operating costs in 2020

"To us, energizing life doesn't just mean supplying safe and reliable power, it also means we are a company that puts people first, especially when they need it most."

On the regulatory front, we continued to work constructively with the Ontario Energy Board (OEB) and secured approval for our 2020-2022 transmission rate application.

We also collaborated with others in the electricity sector, including the Ontario Energy Association and the Electricity Distributors Association, to bring a united voice to government and to regulatory policy decisions.

Customer Advocacy: In addition to the Pandemic Relief Program, we undertook a number of initiatives that put people first and supported customers through COVID-19. Our customer advocacy efforts, for example, successfully led to residential customers – for the first time ever – having choice in their pricing plans.

We voluntarily deferred rate increases for our transmission customers and extended financial relief and flexibility to small businesses that have been experiencing hardship. We applaud the Ontario government's decision to help our commercial and industrial customers save between 14%-16%, enabling Ontario businesses to be competitive with other North American jurisdictions. We also supported the government's decision to introduce a temporary electricity relief rate for residential, small business and farm customers.

Customers responded to our efforts to keep them connected to safe and reliable power while helping them access financial relief programs and more flexible service options. We received a record high residential and small business customer satisfaction rate of 87%.

Innovate and Grow the Business: We are pursuing investments designed to energize life for Ontarians well into the future. As part of our strategy to be the provider of choice for Ontario communities, we successfully completed the acquisition of Orillia Power Distribution Corporation and the business assets of Peterborough Distribution Inc. Joining the Hydro One family are approximately 51,000 new customers and over 75 employees. This consolidation of our business benefits all Hydro One customers because it makes the provincial grid more efficient, while reducing costs across the system.

We officially launched our innovative joint venture Ivy Charging Network™ (Ivy) in 2020 to support a greener transportation sector. Ivy opened 23 fast charging sites across Ontario, and is on track to have over 160 fast chargers across approximately 60 locations in Ontario by the end of 2021.

Our IT team leveraged our secure technology environment to seamlessly transition a large portion of employees to work-from-home. Additionally, the substantial increase in Ontarians working from home increased demand for Hydro One Telecom's service, resulting in the expansion of its fibre connectivity options and more cloud services, data backup tools and secure data storage for business customers to choose from.

Strong Foundation, Sustainable Future

Looking forward, we are energized by the possibilities ahead. While COVID-19 has brought new challenges to Hydro One, our ability to quickly learn and adapt gives me great confidence that we will emerge from this pandemic as a stronger organization. To us, energizing life doesn't just mean supplying safe and reliable power, it also means we are a company that puts people first, especially when they need it most.

We stand ready to help power Ontario's economic recovery from this global pandemic. To that end, we are preparing for the upcoming joint rate application for both our transmission and distribution businesses. As a company that puts customers first we engaged in an extensive customer outreach to inform the development of our investment plan. This plan will inform our views and plans on affordability, service levels, and sustainability over the next five years, starting in 2023. We expect to file our application later this year, and we look forward to a regulatory decision that will provide clarity and stability in our transmission and distribution capital plans, allowing us to focus on executing our strategy.

On behalf of everyone at Hydro One, I thank Darlene Bradley and Saylor Militz-Lee for their service to our organization and I welcome Lyla Garzouzi, our new Chief Safety Officer and Megan Telford, our new Chief Human Resources Officer, to our leadership team. Finally, I want to thank Hydro One employees for the incredible passion, pride, ingenuity and resilience you have shown during these uncertain times. Your commitment has enabled us to deliver great results to our shareholders and proudly energize life for our customers and communities across Ontario.

Mark Poweska
President and Chief Executive Officer

Hydro One's Pandemic Response

Hydro One has played a critical role in energizing life in Ontario throughout the pandemic – supporting families, the economy and those on the frontlines fighting this virus. Our priorities have been to ensure the safety of our employees and customers, and to support the electricity grid to keep all essential services operating and the economy open and ready to grow again.

Easing Customer Hardship

Hydro One has a deep responsibility to support our customers as they navigate these challenging times. We are focused on keeping customers connected and advocating for the programs that help them avoid the stress of falling behind. Through our Pandemic Relief Program, we are providing financial assistance and increased payment flexibility to residential and small business customers experiencing hardship. We also extended our Winter Relief Program to ensure our residential customers stayed connected during this challenging time and suspended late payment fees for all our customers.

We introduced other measures to provide our customers with rate relief including the return of approximately $5 million in security deposits to more than 4,000 commercial businesses; and connecting customers with the government's enhanced COVID-19 Energy Assistance Program (CEAP) for residential and small business customers (as well as registered charities), which offers one-time credits on their bill.[3]

We will continue to stand with Ontarians, providing them with relief, flexibility and choice now and in the future.

Standing With Our Communities

Hydro One aspires to help build safe communities across Ontario. As a result of COVID-19, our community investment work has become more critical than ever. We focused on protecting society's most vulnerable during this period of uncertainty.

- We partnered with GlobalMedic, a registered Canadian charity specializing in disaster relief, to deliver 13,500 critical aid kits of food and safety supplies – including food staples, reusable face masks and soap – to Indigenous communities across the province during the COVID-19 pandemic.
- We supported the Métis Nation of Ontario's (MNO's) pandemic relief fund and its 31 community councils, helping them provide food, medical and pharmaceutical supplies to their vulnerable citizens.
- We supported Feed Ontario's COVID-19 Emergency Food Box Program, donating $300,000 worth of meals through customer, employee and social media campaigns. With the help of our community, we were able to donate an additional 51,000 meals to those in need.
- We fast-tracked $32.9 million in payments to small, medium and Indigenous suppliers in Ontario to help with much needed cash flow.

[3] In late December 2020, Hydro One offered enhanced CEAP and CEAP-Small Business (CEAP-SB) benefits for 2021 in recognition of the impact the second wave of COVID-19 was having on our customers.

13,500
food and safety kits provided to First Nations communities

$300,000
worth of meals through customer, employee and social media campaigns

A better & brighter future for all

Energizing Life

Hydro One has a critical role to play in helping Ontario emerge stronger from the COVID-19 global pandemic. We will achieve this by building a more sustainable business, supporting our communities, and contributing to a more inclusive and equitable society.

In 2020, we continued to execute the sustainability priorities of our corporate strategy – climate change and extreme weather, Indigenous and community partnerships and diversifying talent – in order to deliver on our vision of a better and brighter future for all.

Supporting the Environment: Hydro One's climate policy and climate change management plan guide our climate-related business activities.

In 2020, we made investments to increase the resiliency of our assets to better withstand the impact of climate change and extreme weather while simultaneously limiting the environmental impacts of our activities.

Responding to demand for greener transportation options, our joint venture Ivy opened 23 electric vehicle fast-charger locations, making charging on-the-go easy and convenient for Ontarians.

Making a Social Impact: COVID-19 brought serious challenges to many communities that worked tirelessly to meet critical and emerging local needs.

In response, we launched a new fund to support those who provide services to Ontarians – helping to strengthen community resiliency and safety. Charitable organizations, municipalities and Indigenous communities were able to apply for up to $25,000 toward pandemic response efforts and initiatives that improve physical and emotional safety. From supporting well-being through an outdoor skating trail or delivering meals to vulnerable populations, the fund helps local organizations build a better and brighter future for their communities.

An Inclusive Equitable Society: Hydro One is on a journey to better understand the experiences of Black, Indigenous Peoples, People of Colour and other marginalized employees at the company in order to address systemic racism and biases, while creating an inclusive environment. As part of this, our CEO Mark Poweska joined other Canadian CEOs in signing the BlackNorth Initiative Pledge – which aims to move Canada toward ending anti-Black systemic racism and creating opportunities for underrepresented groups. We are committed to listening, understanding, and examining our own assumptions in order to eliminate unconscious bias in the workplace and to promote racial equity. We are also committed to identifying systemic barriers and putting plans in place to remove and prevent them in the future, all in an effort to advance racial equity.

We established a new Diversity and Inclusion Council, which has a mandate to advocate for and drive change on diversity, inclusion and equity programming, initiatives, and policies.

Transparent Governance: Hydro One is committed to transparent disclosures in our ESG reporting. That is why we enhanced our sustainability reporting to align with the Global Reporting Initiative's (GRI) core standards and the Sustainability Accounting Standards Board (SASB) framework. We also committed to aligning our climate-related disclosures with the Taskforce on Climate-related Financial Disclosures (TCFD) over time.

$42m
total procurement spending with Indigenous businesses in 2020

50%
fleet conversion of sedans and SUVs to electric vehicles or hybrids by 2025

Corporate Governance

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. 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, supports strong corporate governance centered on independence, integrity and accountability which is in the best interests of shareholders, and promotes and strengthens relationships with our customers, employees, the communities where we operate and other stakeholders.

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 establishing and maintaining best corporate governance practices. The company's practices are fully aligned with the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange.

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 the Province of Ontario.

In 2020, the Board revised the structure and mandates of its committees to support Hydro One's new corporate strategy. The Board established the Indigenous Peoples, Safety & Operations Committee[4] (IPSO) in order to elevate the importance of an improved safety culture and strong First Nations partnerships. The IPSO Committee also oversees the company's sustainability and climate change strategies and major capital projects. The Board also recognized the importance of regulatory and public policy matters within the electricity sector by establishing the Governance & Regulatory committee[5].

Board of Directors and Committees (as of March 23, 2021)

★ Chair • Committee Member

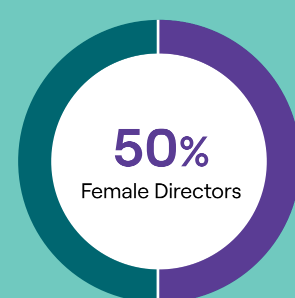
Committees	Audit	Governance & Regulatory	Human Resources	Indigenous Peoples, Safety & Operations[4]
Timothy Hodgson (Chair)				
Mark Poweska (President & CEO)				
Cherie Brant	•			•
Blair Cowper-Smith		★	•	
David Hay	•			★
Jessica McDonald			•	•
Stacey Mowbray[6]		•		•
Russel Robertson	★		•	
William Sheffield	•	•		
Melissa Sonberg	•		★	
Susan Wolburgh Jenah		•		•

[4] Previously the Health, Safety, Environment and Indigenous Peoples Committee
[5] Previously the Governance Committee
[6] Became a director on July 23, 2020

Hydro One's Gender Balanced Independent Board of Directors

Much work remains in advancing diversity and inclusion at all levels of Hydro One to better reflect where we work and the communities we represent across the province. However, we are pleased to note, that with the appointment of Stacey Mowbray, the current composition of our Independent Non Executive Board Members are five women (50%) and five men (50%). We believe this balance makes us one of the most gender progressive boards in North America, reflecting best practices in board diversity and surpassing our Catalyst Accord commitment to maintaining at least 30% female board members.

Board Gender Diversity[1]

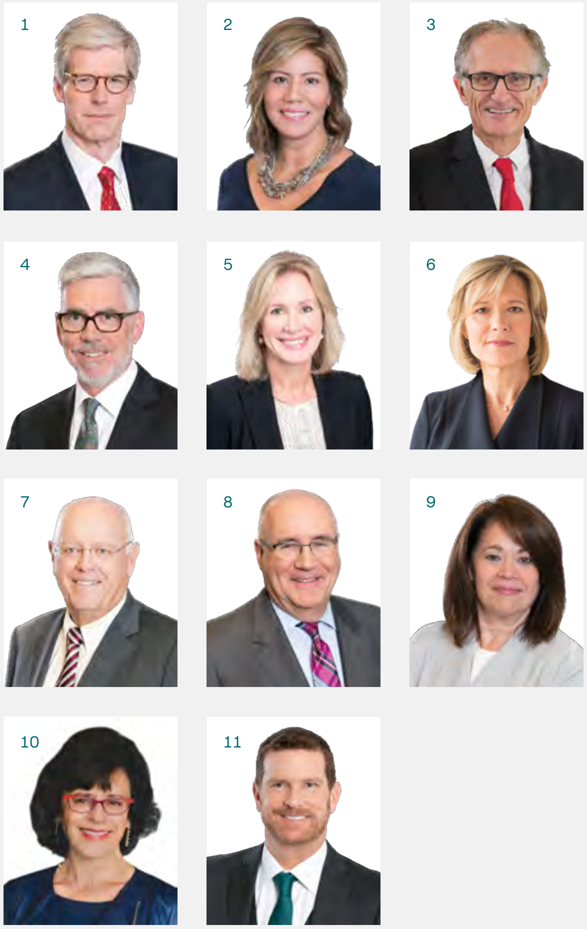


Male **50%** Female **50%**

[1] Hydro One s Independent Non Executive Board Members

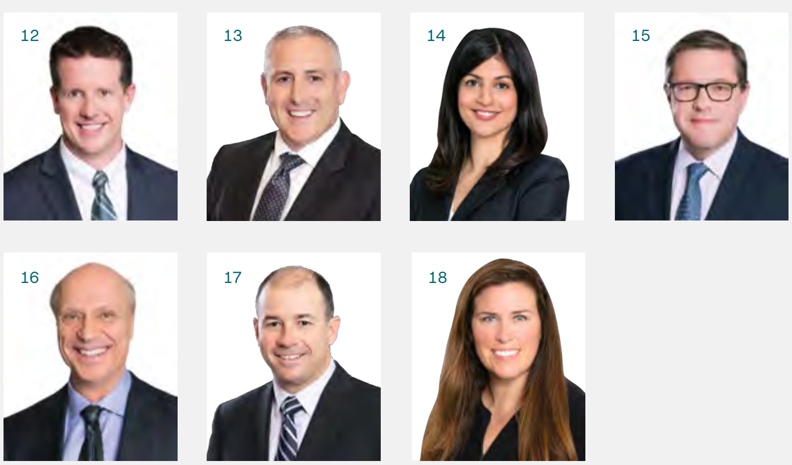
To learn more about the Directors, committee mandates and composition, go to www.HydroOne.com/Investors

Board of Directors



1. **Timothy Hodgson,** MBA, FCPA, ICD.D
Corporate Director, Chair of Hydro One Ltd, Chair of Sagicor Financial Company Limited, Director Public Sector Pension Investment Board (PSP Investments), Former Director Alignvest Acquisition II Corporation, retired Managing Partner Alignvest Management Corporation, Former Special Advisor to Bank of Canada Governor Mark Carney, Former CEO Goldman Sachs Canada
2. **Cherie Brant,** J.D.
Partner, Borden Ladner Gervais LLP, Director Anishnawbe Health Foundation, Director Canadian Council for Aboriginal Business, Aboriginal Education Council for Centennial College, Aboriginal Energy Working Group-IESO
3. **Blair Cowper-Smith,** LLB, LLM, ICD.D
Principal and founder Erin Park Business Solutions, Former Chief Corporate Affairs Officer OMERS
4. **David Hay,** LLB, ICD.D
Managing Director Delgatie Incorporated, Former President and CEO New Brunswick Power Corporation, Former Vice-Chair and Managing Director of CIBC World Markets Inc., Director EPCOR Utilities Inc., Council Member of the Council for Clean and Reliable Energy
5. **Jessica McDonald,** ICD.D
Corporate Director, Former Chair, Canada Post Corporation, Former President & CEO BC Hydro & Power Authority, Director Coeur Mining Inc., Member Council of Sustainable Development Technology Canada and Greater Vancouver Board of Trade
6. **Stacey Mowbray,** MBA, BBA
Corporate Director, Former President North America WW International (formerly Weight Watchers), Director Currency Exchange International, Director Sleep Country Canada Holdings Inc., Director Bonne O Holdings, Volunteer on the Operating Board of Trillium Health Partners
7. **Russel Robertson,** FCPA, FCA, ICD.D
Corporate Director, Former EVP and Head, Anti-Money Laundering, BMO Financial Group, Former Vice-Chair, Deloitte & Touche LLP (Canada), Director Bausch Health Companies Inc., Director Turquoise Hill Resources Ltd.
8. **William Sheffield,** BSC, MBA, ICD.D
Corporate Director, Former CEO Sappi Fine Papers, Director Houston Wire & Cable Company, Director Velan Inc., Former Board Member OPG
9. **Melissa Sonberg,** BSC, MHA, ICD.D
Professor in Practice, McGill University, Desautels Faculty of Management, Director Exchange Income Corporation, Director Athennian, Director Group Touchette, Director Canadian Professional Sales Association, Director Women in Capital Markets, Former Senior Vice President, Human Resources & Corporate Affairs and Senior Vice President, Global Brands, Communications and External Affairs at AIMIA
10. **Susan Wolburgh Jenah,** J.D., ICD.D
Corporate Director, Director Laurentian Bank of Canada, Director Aecon Group Inc, and Vice-Chair Humber River Hospital. Member of the Independent Review Committee of Vanguard Investments Canada, and Former Public Governor of the U.S. Financial Industry Regulatory Authority (FINRA)
11. **Mark Poweska,** President and CEO of Hydro One Limited, Former Executive Vice President, Operations at BC Hydro, Chair of Ontario Energy Association, Director Western Energy Institute

Executive Leadership Team



11. **Mark Poweska**
President and Chief Executive Officer
12. **Brad Bowness**
Chief Information Officer
13. **Jason Fitzsimmons**
Chief Corporate Affairs & Customer Care Officer
14. **Lyla Garzouzi**
Chief Safety Officer
15. **Paul Harricks**
Chief Legal Officer
16. **David Lebeter**
Chief Operating Officer
17. **Chris Lopez**
Chief Financial Officer
18. **Megan Telford**
Chief Human Resources Officer

For detailed biographical information of Hydro One Limited Board members, visit www.HydroOne.com/Investors.
The biographical information of Hydro One Limited Board members is based on information available as of March 23, 2021.

Hydro One's

Business Network

Our Regulated Business

Transmission: Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to distribution companies and industrial customers across Ontario. Our system accounts for approximately 98%[7] of Ontario's transmission capacity with approximately 30,000 circuit kilometres of high-voltage transmission lines. We also own and operate 25 cross-border interconnections with neighbouring provinces and the United States, which allow electricity to flow into and out of Ontario.

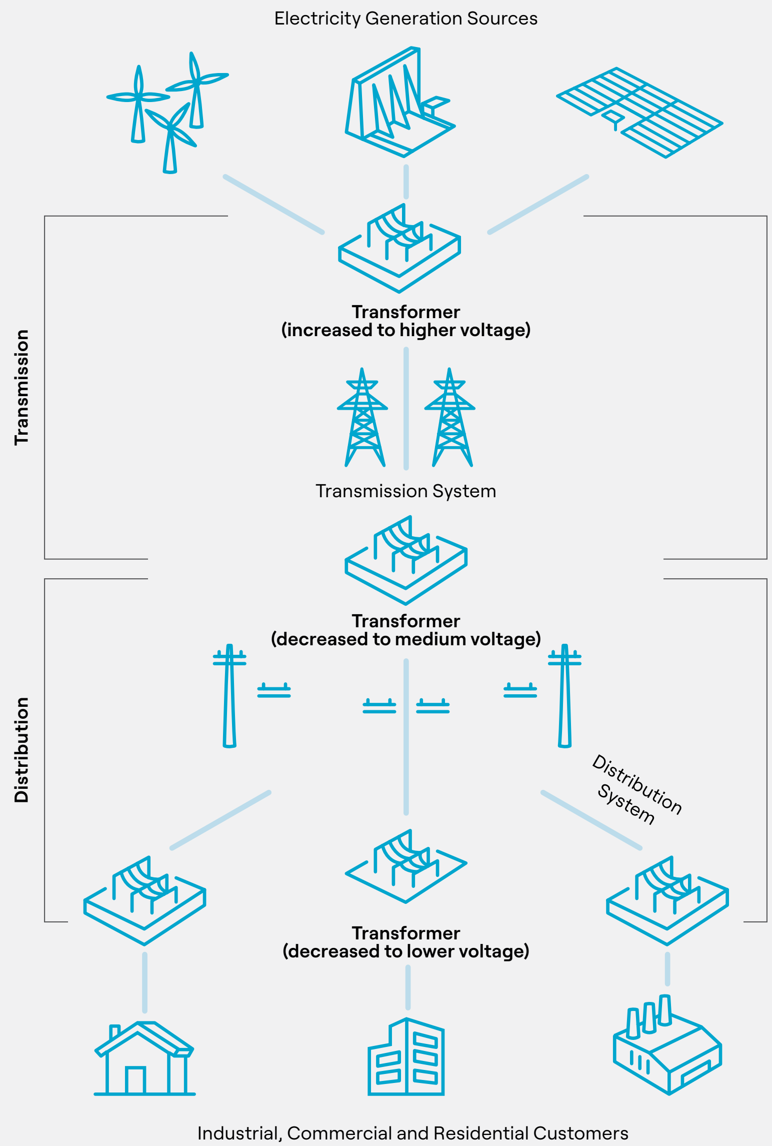
Distribution: Our distribution system is the largest[8] in Ontario. It consists of approximately 124,000 circuit kilometres of primary low-voltage power lines serving approximately 1.4 million customers, mostly in rural areas. As well, Hydro One Remote Communities Inc. serves customers in one grid-connected and 21 off-grid communities in Ontario's far north.

Our Unregulated Business

Our other segment consists principally of our telecommunications business, Hydro One Telecom Inc. (HOT), which provides telecommunications support for Hydro One's transmission and distribution businesses, as well as for its other business customers. HOT offers comprehensive communications and information technology services and solutions (cloud services, managed services and security-based services) to businesses that extend beyond the core fibre and connectivity services it has traditionally offered.

Hydro One's Role in the Ontario Electric Power System

Our transmission and distribution systems safely and reliably serve communities throughout Ontario. Our customers are suburban, rural and remote homes and businesses across the province. Our communities are proudly and safely serviced by a team of skilled and dedicated employees.



[7] Based on revenue approved by the OEB
[8] Based on customers (per OEB yearbook)

Why invest?

Hydro One is a unique low risk opportunity to participate in the transformation of a premium large scale electric utility.

1

Everyone Uses Electricity

One of the largest electricity utilities in North America, with significant scale and leadership position across Canada's most populated province.

2

Strong Balance Sheet

One of the strongest investment grade balance sheets in the North American utility sector.

3

Pure play Transmission and Distribution

Unique combination of electric power transmission and local distribution, with no power generation assets or material exposure to commodity prices.

4

Stable Operations

Stable and growing cash flows with 99% of business fully rate regulated in a constructive, transparent and collaborative regulatory environment.

5

Financial Performance

Predictable self funding organic growth profile with expanding rate base and strong cash flows, together with broad support for refurbishment of aging infrastructure and with ~5% expected rate base CAGR.[9] No external equity required to fund planned growth.

6

Transparent ESG Reporting

Transparency in our environmental, social and governance (ESG) reporting.

7

Attractive Dividend

Annualized dividend of $1.0144 per share with attractive 70% 80% target payout ratio.

8

Rate Base Expansion

Opportunity for continued dividend growth with rate base expansion, continued consolidation and efficiency realization.

[9] Compound Annual Growth Rate (CAGR)

Financial Highlights

Year ended December 31 (millions of dollars, except as otherwise noted)	**2020**	2019
Revenues	**7,290**	6,480
Purchased power	**3,854**	3,111
Revenues, net of purchased power[1]	**3,436**	3,369
Operation, maintenance and administration (OM&A) costs	**1,070**	1,181
Depreciation, amortization and asset removal costs	**884**	878
Financing charges	**471**	514
Income tax expense recovery	**(785)**	(6)
Net income (loss) to common shareholders of Hydro One	**1,770**	**778**
Adjusted net income to common shareholders of Hydro One[1]	**903**	**918**
Basic earnings per common share (EPS)	**$2.96**	$1.30
Diluted EPS	**$2.95**	$1.30
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$1.51**	$1.54
Diluted Adjusted EPS[1]	**$1.51**	$1.53
Net cash from operating activities	**2,030**	1,614
Funds from operations (FFO)[1]	**1,830**	1,532
Capital investments	**1,878**	1,667
Assets placed in-service	**1,639**	1,703
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**20,091**	19,896
Distribution: Electricity distributed to Hydro One customers (GWh)	**28,379**	27,536
Debt to capitalization ratio[2]	**56.3%**	56.3%

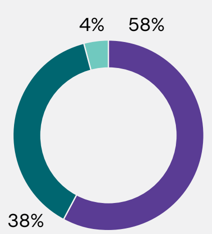
1. See section "Non-GAAP Measures" for description and reconciliation of adjusted net income, basic and diluted Adjusted EPS, FFO and revenues, net of purchased power.
2. Debt to capitalization ratio is a non-GAAP measure and has been calculated as total debt (including total long-term debt and short-term 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. Management believes that the debt to capitalization ratio is helpful as a measure of the proportion of debt in the Company's capital structure.

This report contains forward-looking information within the meaning of applicable Canadian securities laws that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and includes beliefs and assumptions made by the management of Hydro One. Such information includes, but is not limited to, statements relating to: Hydro One's investments in infrastructure and technology to build a sustainable grid, Hydro One's stable and growing cash flows, organic growth profile, expanding rate base and cash flows, expected rate base CAGR, and the elements of Hydro One's strategy, including expectations regarding the company's transmission and distribution rate applications and resulting decisions, rates and impacts. 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. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One Limited's and Hydro One Inc.'s filings with the securities regulatory authorities in Canada, which are available on SEDAR at www.sedar.com. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

All figures in this document are approximate figures that are rounded to the nearest decimal place.

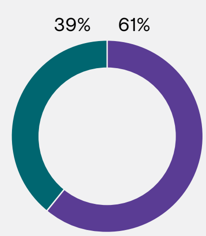
Total Assets

$30.3b



Rate Base

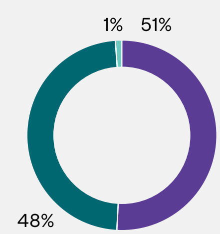
$21.7b



Revenues

(Net of purchased power costs)

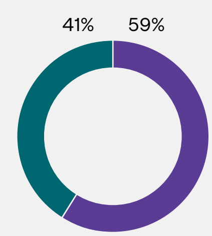
$3.44b



Regulated Earnings

(Before financing charges and income taxes)

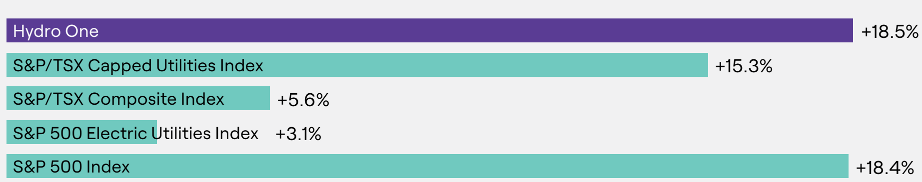
$1.5b



● Transmission ● Distribution ● Other

Total Shareholder Return (TSR)

January 1, 2020 to December 31, 2020



Financial Report

Contents

Management's Discussion and Analysis

For the years ended December 31, 2020 and 2019

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, 2020. The Consolidated Financial Statements 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. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canadian securities laws and regulations, which can vary from those of the US. This MD&A provides information as at and for the year ended December 31, 2020, based on information available to management as of February 23, 2021.

Consolidated Financial Highlights and Statistics

Year ended December 31 (millions of dollars, except as otherwise noted)	**2020**	2019	Change
Revenues	**7,290**	6,480	12.5%
Purchased power	**3,854**	3,111	23.9%
Revenues, net of purchased power[1]	**3,436**	3,369	2.0%
Operation, maintenance and administration (OM&A) costs	**1,070**	1,181	(9.4%)
Depreciation, amortization and asset removal costs	**884**	878	0.7%
Financing charges	**471**	514	(8.4%)
Income tax recovery	**(785)**	(6)	12,983%
Net income to common shareholders of Hydro One	**1,770**	**778**	**127.5%**
Adjusted net income to common shareholders of Hydro One[1]	**903**	**918**	**(1.6%)**
Basic earnings per common share (EPS)	**$ 2.96**	$ 1.30	127.7%
Diluted EPS	**$ 2.95**	$ 1.30	126.9%
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$ 1.51**	$ 1.54	(1.9%)
Diluted Adjusted EPS[1]	**$ 1.51**	$ 1.53	(1.3%)
Net cash from operating activities	**2,030**	1,614	25.8%
Funds from operations (FFO)[1]	**1,830**	1,532	19.5%
Capital investments	**1,878**	1,667	12.7%
Assets placed in-service	**1,639**	1,703	(3.8%)
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**20,091**	19,896	1.0%
Distribution: Electricity distributed to Hydro One customers (GWh)	**28,379**	27,536	3.1%

As at December 31	**2020**	2019
Debt to capitalization ratio[2]	**56.3%**	56.3%

1 See section "Non-GAAP Measures" for description and reconciliation of adjusted net income, basic and diluted Adjusted EPS, FFO and revenues, net of purchased power.

2 Debt to capitalization ratio is a non-GAAP measure and has been calculated as total debt (including total long-term debt 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. Management believes that the debt to capitalization ratio is helpful as a measure of the proportion of debt in the Company's capital structure.

Overview

Through its wholly-owned subsidiary Hydro One Inc., Hydro One is Ontario's largest electricity transmission and distribution utility. Hydro One owns and operates substantially all of Ontario's electricity transmission network and is the largest electricity distributor in Ontario by number of customers. The Company's regulated transmission and distribution operations are owned by Hydro One Inc. Hydro One delivers electricity safely and reliably to approximately 1.4 million customers across the province of Ontario, and to large industrial customers and municipal utilities. Hydro One Inc. owns and operates approximately 30,000 circuit kilometres of high-voltage transmission lines and approximately 124,000 circuit kilometres of primary low-voltage distribution lines. Hydro One has three segments: (i) transmission; (ii) distribution; and (iii) other.

For the years ended December 31, 2020 and 2019, Hydro One's segments accounted for the Company's total revenues, net of purchased power, as follows:

Year ended December 31	**2020**	2019
Transmission	**51%**	49%
Distribution	**48%**	50%
Other	**1%**	1%

As at December 31, 2020 and 2019, Hydro One's segments accounted for the Company's total assets as follows:

Year ended December 31	**2020**	2019
Transmission	**58%**	56%
Distribution	**38%**	37%
Other	**4%**	7%

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). As at December 31, 2020, the Company's 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), as well as an approximately 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation (SON), and an approximately 55% interest in Niagara Reinforcement Limited Partnership (NRLP), a limited partnership between Hydro One and Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation (collectively, the First Nations Partners). The Company's transmission business is rate-regulated and earns revenues mainly by charging transmission rates that are approved by the OEB.

As at and for the year ended December 31	**2020**	2019
Electricity transmitted[1] (MWh)	**132,225,424**	135,101,455
Transmission lines spanning the province (circuit-kilometres)	**30,093**	30,122
Rate base (millions of dollars)	**13,185**	12,609
Capital investments (millions of dollars)	**1,157**	1,035
Assets placed in-service (millions of dollars)	**948**	1,082

1 Electricity transmitted represents total electricity transmitted in Ontario by all transmitters.

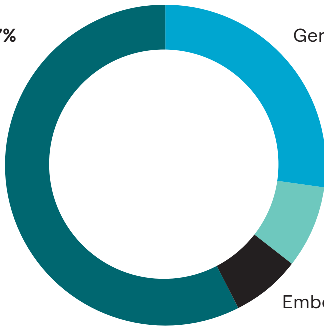
Distribution Segment

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, Hydro One Remote Communities Inc. (Hydro One Remote Communities), and Orillia Power Distribution Corporation (Orillia Power), as well as the distribution business and assets acquired from Peterborough Distribution Inc. (Peterborough Distribution). Please see section "Other Developments" for additional information regarding the acquisition of Orillia Power and the acquisition of the business and distribution assets of Peterborough Distribution. The Company's distribution business is rate-regulated and earns revenues mainly by charging distribution rates that are approved by the OEB.

As at and for the year ended December 31	**2020**	2019
Electricity distributed to Hydro One customers (GWh)	**28,379**	27,536
Electricity distributed through Hydro One lines (GWh)[1]	**39,131**	38,446
Distribution lines spanning the province (circuit-kilometres)	**124,571**	123,422
Distribution customers (number of customers)	**1,449,629**	1,381,011
Rate base (millions of dollars)	**8,505**	8,101
Capital investments (millions of dollars)	**712**	624
Assets placed in-service (millions of dollars)	**684**	602

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).

2020 Distribution Revenues



Other Segment

Hydro One's other segment consists principally of its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, as well as certain corporate activities.

The telecommunication business is carried out by Hydro One's wholly-owned subsidiary Hydro One Telecom Inc. (Hydro One Telecom). In addition to supporting Hydro One's regulated business segments, Hydro One Telecom offers comprehensive communications and information technology (IT) services and solutions (for example, cloud services, managed services and security-based services) that extend beyond its fibre optic network, in a competitive commercial market. Hydro One Telecom is not regulated by the OEB, however Hydro One Telecom is registered with the Canadian Radio-television and Telecommunications Commission as a non-dominant, facilities-based carrier, providing broadband telecommunications services in Ontario with connections to Montreal, Quebec; Buffalo, New York; and Detroit, Michigan.

Hydro One's other segment also includes the deferred tax asset which arose from the revaluation of the tax bases of Hydro One's assets to fair market value when the Company transitioned from the provincial payments in lieu of tax regime to the federal tax regime at the time of the Company's initial public offering in 2015.

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 associated with providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues primarily consist of regulated distribution rates approved by the OEB, as well as the recovery of purchased power costs. 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: (i) the wholesale commodity cost of energy; (ii) the Global Adjustment, which is the difference between the guaranteed price and the money the generators earn in the wholesale marketplace; and (iii) the wholesale market service and transmission charges levied by the IESO. Hydro One passes on 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

OM&A costs are incurred to support the operation and maintenance of the transmission and distribution systems, and include other costs such as property taxes related to transmission and distribution stations and buildings, and the operation of IT systems. Transmission OM&A costs are required 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 distances 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, Amortization and Asset Removal Costs

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. Asset removal costs consist of 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, as well as gains and losses on interest rate swap agreements, 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, 2020 of $1,770 million is an increase of $992 million, or 127.5%, from the prior year. Significant influences on net income included:

- higher revenues, net of purchased power, primarily resulting from:
  - an increase in transmission revenues primarily due to the OEB's decision on 2020 rates; partially offset by
  - a decrease in distribution revenues, net of purchased power, mainly due to 2018 foregone revenue recognized in March 2019 following the receipt of the OEB decision on rates; partially offset by the OEB's decision on 2020 rates and revenues related to the Peterborough Distribution and Orillia Power acquisitions which closed during the third quarter of 2020.
- lower OM&A costs primarily resulting from:
  - the payment of the termination fee in 2019 related to the terminated acquisition of Avista Corporation (Merger);
  - lower vegetation management and work program expenditures, and the 2019 write-off of the Lake Superior Link project; partially offset by
  - costs related to COVID-19, as discussed below;
  - additional other post-employment benefit (OPEB) costs that are recognized in OM&A following the 2020-2022 OEB transmission decision and recovered in rates, therefore net income neutral; and
  - lower insurance proceeds received in 2020.
- lower financing charges primarily resulting from financing costs related to the Merger incurred in the first quarter of 2019; partially offset by an increase in interest expense on long-term debt due to increased debt levels in 2020.
- higher income tax recovery primarily attributable to:
  - income tax recovery recorded following the July 2020 decision of the Ontario Divisional Court (ODC Decision); partially offset by
  - 2019 income tax recovery following the payment of the termination fee and financing charges related to the Merger; and
  - lower incremental tax deductions and deductible temporary differences.

Included in the Company's results for the year ended December 31, 2020 are costs incurred as a result of the COVID-19 pandemic. Total COVID-19 related costs of $50 million consist primarily of labour costs associated with the temporary stand-down of the Company's workforce in the first half of the year, the recognition of the bad debt provision following the issuance of the OEB staff proposal in December 2020, and other direct expenses, including purchases of additional facility-related cleaning supplies.

For additional disclosure related to the impact of COVID-19 on the Company's operations for the year ended December 31, 2020, please see section "Other Developments – COVID-19".

EPS and Adjusted EPS

EPS was $2.96 for the year ended December 31, 2020, compared to EPS of $1.30 in 2019. The increase in EPS was driven by higher earnings for the year ended December 31, 2020, as discussed above. Adjusted EPS, which excludes the impacts of the income tax recovery related to the ODC Decision received in 2020, and for income and costs related to the Merger in 2019, was $1.51 for the year ended December 31, 2020, compared to $1.54 in 2019. The decrease in Adjusted EPS was driven by changes in net income for the year ended December 31, 2020, as discussed above, but excluding the impacts of the Merger and the ODC Decision. See section "Non-GAAP Measures" for description and reconciliation of Adjusted EPS.

Revenues

Year ended December 31 (millions of dollars, except as otherwise noted)		**2020**	2019	Change
Transmission		**1,740**	1,652	5.3%
Distribution		**5,507**	4,788	15.0%
Other		**43**	40	7.5%
Total revenues		**7,290**	6,480	12.5%
Transmission		**1,740**	1,652	5.3%
Distribution, net of purchased power[1]		**1,653**	1,677	(1.4%)
Other		**43**	40	7.5%
Total revenues, net of purchased power[1]		**3,436**	3,369	2.0%
Transmission:	Average monthly Ontario 60-minute peak demand (MW)	**20,091**	19,896	1.0%
Distribution:	Electricity distributed to Hydro One customers (GWh)	**28,379**	27,536	3.1%

1 See section "Non-GAAP Measures" for description and reconciliation of distribution revenues, net of purchased power, and revenues, net of purchased power.

Transmission Revenues

Transmission revenues increased by 5.3% during the year ended December 31, 2020, primarily due to the following:

- the OEB's decision on 2020 rates, including:
  - the recovery of certain OPEB costs through OM&A that were previously capitalized and recovered in rates, therefore net income neutral, and
  - the recognition of Conservation and Demand Management (CDM) revenues in the second quarter of 2020; partially offset by deferred regulatory adjustment related to transmission asset removal costs in 2020,
- full year contribution of the NRLP assets placed in-service in the third quarter of 2019.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, decreased by 1.4% during the year ended December 31, 2020 primarily due to the following:

- the 2018 foregone revenue recognized in prior year following the 2019 OEB decision on rates; and
- the suspension of late payment charges following the onset of COVID-19; partially offset by
- the OEB's decision on 2020 rates;
- distribution revenues related to the Peterborough Distribution and Orillia Power acquisitions which closed during the third quarter of 2020; and
- a lower deferred regulatory adjustment related to the Earnings Sharing Mechanism in 2020.

OM&A Costs

Year ended December 31 (millions of dollars)	**2020**	2019	Change
Transmission	**391**	355	10.1%
Distribution	**619**	610	1.5%
Other	**60**	216	(72.2%)
	1,070	1,181	(9.4%)

Transmission OM&A Costs

The 10.1% increase in transmission OM&A costs for the year ended December 31, 2020 was primarily due to the following:

- additional OPEB costs that are recognized in OM&A following the 2020-2022 OEB transmission decision and recovered in rates, therefore net income neutral;
- costs related to COVID-19, primarily consisting of labour costs associated with the temporary stand-down of the Company's workforce in the first half of the year, and other direct expenses; and
- lower insurance proceeds received in 2020; partially offset by
- lower work program expenditures related to stations and lines maintenance.

Distribution OM&A Costs

The 1.5% increase in distribution OM&A costs for the year ended December 31, 2020 was primarily due to the following:

- costs related to COVID-19, primarily consisting of labour costs associated with the temporary stand-down of the Company's workforce in the first half of the year, the recognition of the bad debt provision following the issuance of the OEB staff proposal in December 2020, and other direct expenses, including purchases of additional facility-related cleaning supplies; and
- costs related Peterborough Distribution and Orillia Power acquisitions which closed during the third quarter of 2020; partially offset by
- lower vegetation management expenditures; and
- lower spend on IT projects.

Other OM&A Costs

The decrease in other OM&A costs for the year ended December 31, 2020 was primarily due to the payment of the Merger termination fee and the write-off of the Lake Superior Link project in the prior year.

Depreciation, Amortization and Asset Removal Costs

The increase of $6 million or 0.7% in depreciation, amortization and asset removal costs in 2020 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 $43 million, or 8.4%, decrease in financing charges for the year ended December 31, 2020 was primarily due to the following:

- financing costs related to the Merger incurred in the first quarter of 2019; and
- lower interest expense on short-term notes due to lower interest rate in the current year; partially offset by
- higher interest expense on long-term debt as a result of increased debt levels driven by the debt issuances completed in 2020.

Income Tax Expense

Income taxes are accounted for using the asset and liability method. Current taxes are recorded based on the taxes expected to be paid in respect of the current and prior years' taxable income. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the respective tax basis of assets and liabilities including carryforward unused tax losses and credits.

As prescribed by the regulators, the Company recovers income taxes in revenues from ratepayers based on estimate of current tax expense in respect of regulated operations. The amounts of deferred income taxes related to regulated operations, which are considered to be more likely-than-not of recovery from, or refund to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred tax expense. Therefore the consolidated tax expense or recovery for the current period is based on the total current and deferred tax expense or recovery, net of the regulatory accounting offset to deferred tax expense arising from temporary differences recoverable from or refundable to customers in the future.

Income tax recovery was $785 million for the year ended December 31, 2020 compared to $6 million in 2019. The $779 million increase in income tax recovery for the year ended December 31, 2020 was principally attributable to the recognition of $867 million income tax recovery arising from the ODC Decision and the recognition of $51 million income tax recovery in 2019 related to the Merger termination fee and related financing charges. When adjusted for these non-recurring recoveries, the adjusted tax expense for the year ended December 31, 2020 was of $82 million compared to $45 million in the same period last year. The $37 million increase in the tax expense is primarily attributable to the following:

- lower incremental tax deductions from deferred tax asset sharing due to the 2018 foregone revenue recognized in 2019 following the receipt of the OEB decision on rates; and
- lower deductible temporary differences.

The Company realized an effective tax rate (ETR) of approximately (77.6%) in 2020, compared to approximately (0.8%) in 2019. Excluding the impact of the income tax recovery related to the ODC Decision received in 2020, and the impacts of costs related to the Merger in 2019, the adjusted ETR of 8.1% for the year ended December 31, 2020, compares to 4.6% in 2019.

See section "Non-GAAP Measures" for description and reconciliation of adjusted tax expense and adjusted ETR.

Common Share Dividends

In 2020, 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 11, 2020	March 11, 2020	March 31, 2020	$ 0.2415	144
May 7, 2020	June 10, 2020	June 30, 2020	$ 0.2536	152
August 10, 2020	September 9, 2020	September 30, 2020	$ 0.2536	151
November 5, 2020	December 9, 2020	December 31, 2020	$ 0.2536	152
				599

Following the conclusion of the fourth quarter of 2020, 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 23, 2021	March 17, 2021	March 31, 2021	$ 0.2536	152

Selected Annual Financial Statistics

Year ended December 31 (millions of dollars, except per share amounts)	**2020**	2019	2018
Revenues	**7,290**	6,480	6,150
Net income (loss) to common shareholders of Hydro One	**1,770**	778	(89)
Basic EPS	**$ 2.96**	$ 1.30	$ (0.15)
Diluted EPS	**$ 2.95**	$ 1.30	$ (0.15)
Basic Adjusted EPS[1]	**$ 1.51**	$ 1.54	$ 1.35
Diluted Adjusted EPS[1]	**$ 1.51**	$ 1.53	$ 1.35
Dividends per common share declared	**$ 1.00**	$ 0.96	$ 0.91
Dividends per preferred share declared[2]	**$ 1.20**	$ 1.06	$ 1.06

As at December 31 (millions of dollars)	**2020**	2019	2018
Total assets	**30,294**	27,061	25,657
Total non-current financial liabilities[3]	**12,813**	10,897	10,479

1 See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS.

2 Preferred dividends per share are calculated using the weighted average number of preferred shares outstanding during each year. The preferred share dividends paid in each year presented were $18 million. All the preferred shares were redeemed on November 20, 2020. See section "Share Capital" for details.

3 Total non-current financial liabilities includes long-term debt, long-term lease obligations, derivative liabilities, long-term accounts payable, and convertible debentures.

Net Income (Loss) – 2019 compared to 2018

Net income attributable to common shareholders for the year ended December 31, 2019 of $778 million is an increase of $867 million or 974.2% from the year prior. Significant influences on earnings included:

- higher revenues, net of purchased power, primarily resulting from:
  - an increase in distribution revenues, net of purchased power, due to the OEB's decision on the 2018 and 2019 distribution rates; partially offset by
  - lower average monthly Ontario 60-minute peak demand and energy consumption driven by less favourable weather in 2019; and
  - lower revenues as a result of deferred tax asset sharing mandated by the OEB and deferred tax regulatory adjustment related to accelerated tax depreciation (Accelerated CCA), both of which will flow through to customers and are offset with lower taxes, with no impact on regulated return on equity (ROE);
- higher OM&A costs primarily resulting from the payment of the termination fee related to the Merger and higher vegetation management coverage; partially offset by lower corporate support costs, insurance proceeds received in 2019, and lower spend on station and lines maintenance programs;
- higher financing charges primarily resulting from an increase in interest expense on long-term debt; and increased Merger-related financing charges; and
- lower income tax expense as a result of the prior year charge to deferred tax expense related to the impairment of Hydro One's deferred income tax regulatory asset, as well as the deferred tax asset sharing and Accelerated CCA, both of which will flow through to customers and are offset with lower revenues, with no impact on regulated ROE.

EPS and Adjusted EPS – 2019 compared to 2018

EPS was $1.30 in 2019, compared to a loss per share of $0.15 in 2018. The increase in EPS was driven by higher earnings in 2019, as discussed above. Adjusted EPS in 2019, which excludes the impacts of the Merger, was $1.54, compared to adjusted EPS of $1.35 in 2018, which excludes the impacts of the OEB's March 2019 reconsideration decision (DTA Decision) relating to Hydro One's treatment of benefits of the deferred tax assets resulting from Hydro One's transition from the provincial payments in lieu of tax regime to the federal tax regime in 2015. The increase in adjusted EPS was driven by the net income impacts discussed above, but excluding the impacts of the Merger and the DTA Decision.

Quarterly Results of Operations

Quarter ended (millions of dollars, except EPS and ratio)	Dec 31, 2020	Sep 30, 2020	Jun 30, 2020	Mar 31, 2020	Dec 31, 2019	Sep 30, 2019	Jun 30, 2019	Mar 31, 2019
Revenues	1,867	1,903	1,670	1,850	1,715	1,593	1,413	1,759
Purchased power	1,046	993	808	1,007	914	737	653	807
Revenues, net of purchased power[1]	821	910	862	843	801	856	760	952
Net income to common shareholders	161	281	1,103	225	211	241	155	171
Adjusted net income to common shareholders[1]	161	281	236	225	211	241	155	311
Basic EPS	$ 0.27	$ 0.47	$ 1.84	$ 0.38	$ 0.35	$ 0.40	$ 0.26	$ 0.29
Diluted EPS	$ 0.27	$ 0.47	$ 1.84	$ 0.38	$ 0.35	$ 0.40	$ 0.26	$ 0.29
Basic Adjusted EPS[1]	$ 0.27	$ 0.47	$ 0.39	$ 0.38	$ 0.35	$ 0.40	$ 0.26	$ 0.52
Diluted Adjusted EPS[1]	$ 0.27	$ 0.47	$ 0.39	$ 0.38	$ 0.35	$ 0.40	$ 0.26	$ 0.52
Earnings coverage ratio[2]	2.8	2.9	n/a	n/a	n/a	n/a	n/a	n/a

1 See section "Non-GAAP Measures" for description of revenues, net of purchased power, adjusted net income and Adjusted EPS.

2 Earnings coverage ratio is a non-GAAP measure that has been presented for the twelve months ended December 31, 2020 and September 30, 2020, and has been calculated as net income before financing charges and income taxes attributable to shareholders of Hydro One, divided by the sum of financing charges and capitalized interest.

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, as well as timing of regulatory decisions.

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 years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)	2020	2019	Change
Transmission	**948**	1,082	(12.4%)
Distribution	**684**	602	13.6%
Other	**7**	19	(63.2%)
Total assets placed in-service	**1,639**	1,703	(3.8%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $134 million or 12.4% during the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to the following:

- the in-servicing of several projects in 2019, including the Niagara Reinforcement Project, the Brant transmission station, the new Leamington transmission, and Enfield transmission station;
- lower volume of overhead lines and component replacements in 2020;
- lower volume of assets placed in-service for IT projects in 2020; and
- lower volume of demand work due to equipment failures in 2020; partially offset by
- timing of assets placed in-service for station sustainment investments (including Lennox transmission station, Sheppard transmission station, Elgin transmission station, Runnymede transmission station, Cherrywood transmission station placed in-service in 2020, and Bronte transmission station, Alexander switching station, Hanmer transmission station, Palmerston transmission station, National Research Council transmission station placed in-service in 2019); and
- assets placed in-service in 2020 (High-Voltage Underground Cable replacement in Toronto, and Kapuskasing area Reinforcement project line upgrade).

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $82 million or 13.6% during the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to the following:

- completion of Customer Contact Centre Technology Modernization project;
- substantial completion of the Leamington transmission station feeder development project in 2020;
- higher volume of storm related asset replacements; and
- completion of Woodstock Operation Centre; partially offset by
- lower volume of distribution station refurbishment work and equipment replacements.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)	2020	2019	Change
Transmission			
Sustaining	**819**	811	1.0%
Development	**226**	143	58.0%
Other	**112**	81	38.3%
	1,157	1,035	11.8%
Distribution			
Sustaining	**317**	272	16.5%
Development	**289**	265	9.1%
Other	**106**	87	21.8%
	712	624	14.1%
Other	**9**	8	12.5%
Total capital investments	**1,878**	1,667	12.7%

Total 2020 capital investments of $1,878 million were largely in-line with the previously disclosed expected amount of $1,841 million.

Transmission Capital Investments
Transmission capital investments increased by $122 million or 11.8% during the year ended December 31, 2020 compared to the year ended December 31, 2019. Principal impacts on the levels of capital investments included:

- higher investments in multi-year development projects, including the new shunt reactors at the Lennox transmission station, the East-West Tie Connection, the new Lakeshore switching station, and the Kapuskasing area reinforcement project;
- higher volume of station refurbishments and replacements;
- investment in the new Ontario grid control centre in the City of Orillia; and
- higher volume of work required to adhere to the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards; partially offset by
- lower volume of overhead line refurbishments and replacements, customer connections, and transportation and work equipment investments.

Distribution Capital Investments
Distribution capital investments increased by $88 million or 14.1% during the year ended December 31, 2020 compared to the year ended December 31, 2019. Principal impacts on the levels of capital investments included:

- investment in the new Ontario grid control centre in the City of Orillia;
- higher volume of storm related asset replacements and emergency power restoration work;
- investment in the new Woodstock Operation Centre;
- higher investments in IT projects including the Customer Contact Centre Technology Modernization project; and
- higher volume of line refurbishments work; partially offset by
- lower volume of transportation and work equipment investments.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2020:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:			(year)	(millions of dollars)	
Wataynikaneyap Power LP Line Connection	Pickle Lake Northwestern Ontario	New stations and transmission connection	2021	28	6
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2022[1]	160	129
Waasigan Transmission Line	Thunder Bay-Atikokan-Dryden Northwestern Ontario	New transmission line	2024[2]	68[2]	6
Leamington Area Transmission Reinforcement[3]	Leamington Southwestern Ontario	New transmission line and stations	2026[3]	525[3]	54
Sustainment Projects:					
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2021	118	115
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2021	146	144
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2023	136	89
Bruce B Switching Station Circuit Breaker Replacement	Tiverton Southwestern Ontario	Station sustainment	2024	146	50
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2026	152	91
Middleport Transmission Station Circuit Breaker Replacement	Middleport Southwestern Ontario	Station sustainment	2025	123	71

1 The East-West Tie Station Expansion project is impacted by the construction schedule of the new East-West Tie transmission line being built by Upper Canada Transmission Inc., operating as NextBridge Infrastructure, LP (NextBridge). In September 2020, NextBridge advised the OEB of a delay in the in-service date of the East-West Tie transmission line to March 31, 2022. As a result of this delay, the majority of the East-West Tie Station Expansion project, enabling the connection and energization of the new East-West Tie transmission line, is now expected to be placed in-service in 2022.

2 The estimated cost of the Waasigan Transmission Line relates to the development phase of the project and the anticipated in-service date reflects the anticipated completion date of the development phase.

3 The Leamington Area Transmission Reinforcement project consists of the construction of a new double-circuit line between Chatham and Leamington and associated transmission stations and connections. The project is currently in the development stage and as such the estimated cost is subject to change. The anticipated in-service dates for the line and stations are between 2022 and 2026.

Future Capital Investments

The Company estimates future capital investments 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 2021 through 2022 transmission capital investment estimates differ from the prior year disclosures, reflecting the OEB's decision on Hydro One Networks' 2021-2022 rate application. See section "Regulation" for further details on the OEB's decision. The 2021 through 2024 distribution capital investments estimates have also been updated to include capital investments for the Peterborough Distribution and Orillia Power acquisitions in the third quarter of 2020. See section "Other Developments" for information related to the acquisitions. The 2021 through 2022 distribution capital investments estimates reflect reprioritization of work and revised pacing of investments. The projections and the timing of the transmission and distribution expenditures in 2023 and 2024 are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2021 to 2024, by business segment:

(millions of dollars)	2021	2022	2023	2024
Transmission	1,172	1,204	1,386	1,380
Distribution	713	648	742	759
Other	23	18	14	11
Total capital investments[1]	1,908	1,870	2,142	2,150

1 Total capital investments for 2021 include $85 million related to a new Ontario grid control centre with an anticipated in-service date of 2021.

The following table summarizes Hydro One's annual projected capital investments for 2021 to 2024, by category:

(millions of dollars)	2021	2022	2023	2024
Sustainment	1,125	1,296	1,555	1,558
Development	544	405	439	459
Other[1]	239	169	148	133
Total capital investments[2]	1,908	1,870	2,142	2,150

1 "Other" capital expenditures include investment in fleet, real estate, IT, and operations technology and related functions.

2 Total capital investments for 2021 include $85 million related to a new Ontario grid control centre with an anticipated in-service date of 2021.

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)	**2020**	2019
Cash provided by operating activities	**2,030**	1,614
Cash provided by (used in) financing activities	**674**	(439)
Cash used in investing activities	**(1,977)**	(1,628)
Increase (decrease) in cash and cash equivalents	**727**	(453)

Cash provided by operating activities

Cash from operating activities increased by $416 million for the year ended December 31, 2020 compared to 2019. The increase was impacted by various factors, including the following:

- higher earnings in 2020;
- changes in certain regulatory accounts; and
- increases in net working capital attributable to higher payments received from the IESO during 2020 associated with Fair Hydro Plan credits, as well as lower non-energy receivables.

Cash provided by (used in) financing activities

Cash provided by financing activities increased by $1,113 million for the year ended December 31, 2020 compared to 2019. The increase was impacted by various factors, including the following:

Sources of cash

- The Company issued $2,725 million of long-term debt in 2020, compared to $1,500 million long-term debt issued in 2019.
- The Company received proceeds of $4,070 million from the issuance of short-term notes in 2020, compared to $4,217 million received in 2019.

Uses of cash

- The Company repaid $4,413 million of short-term notes in 2020, compared to $4,326 million repaid in 2019.
- The Company repaid $653 million of long-term debt in 2020, compared to $730 million of long-term debt in 2019.
- In 2019, the Company redeemed $513 million of convertible debentures.
- Dividends paid in 2020 were $617 million, consisting of $599 million of common share dividends and $18 million of preferred share dividends, compared to dividends of $588 million paid in 2019, consisting of $570 million of common share dividends and $18 million of preferred share dividends.
- The Company redeemed preferred shares of $418 million in 2020, compared to no preferred shares redeemed in 2019. See section "Share Capital" for details of the preferred shares redemption.

Cash used in investing activities

Cash used in investing activities increased by $349 million for the year ended December 31, 2020 compared to 2019. The increase is primarily attributable to a $216 million increase in capital expenditures in 2020, as well the acquisitions of Orillia Power and the assets of Peterborough Distribution in the current year ($126 million). Please see section "Capital Investments" for comparability of capital investments made by the Company during the year ended December 31, 2020 compared to prior year.

Liquidity and Financing Strategy

Short-term liquidity is provided through FFO, 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 $2,300 million in short-term notes with a term to maturity of up to 365 days.

At December 31, 2020, Hydro One Inc. had $800 million in commercial paper borrowings outstanding, compared to $1,143 million outstanding at December 31, 2019. In addition, the Company has revolving bank credit facilities (Operating Credit Facilities) with a total availability balance of $2,550 million as at December 31, 2020. No amounts were drawn on the Operating Credit Facilities as at December 31, 2020 or 2019. The Company may use the Operating Credit Facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, available cash on hand and anticipated levels of FFO are expected to be sufficient to fund the Company's operating requirements. The Company's currently available liquidity is also expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Company's cash requirements. See section "Other Developments – COVID-19" for additional information of the impact of COVID-19 on the Company's operations.

At December 31, 2020, the Company had long-term debt outstanding in the principal amount of $13,558 million, which included $425 million of long-term debt issued by Hydro One, $12,995 million of long-term debt issued by Hydro One Inc., and long-term debt in the principal amount of $138 million issued by HOSSM. The long-term debt issued by Hydro One was issued under its base shelf prospectus (Universal Base Shelf Prospectus), as further described below. The majority of long-term debt issued by Hydro One Inc. has been issued under its Medium Term Note (MTN) Program, as further described below. The long-term debt consists of notes and debentures that mature between 2021 and 2064, and as at December 31, 2020, had a weighted-average term to maturity of approximately 14.5 years (2019 – 15.7 years) and a weighted-average coupon rate of 3.8% (2019 – 4.2%).

On August 20, 2020, Hydro One filed a short form Universal Base Shelf Prospectus with securities regulatory authorities in Canada to replace a previous prospectus that expired in July 2020. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $2,000 million of debt, equity or other securities, or any combination thereof, during the 25-month period ending in September 2022. On October 15, 2020, Hydro One issued $425 million of long-term debt resulting in $1,575 million remaining available for issuance under the Universal Base Shelf Prospectus at December 31, 2020. The Company used the net proceeds of this offering to fund the redemption on November 20, 2020 of all of its Series 1 preferred shares (Preferred Shares) and for general corporate purposes. See section "Share Capital" for further details of the Preferred Shares redemption.

On September 21, 2020, in order to secure required funding for the redemption of the Preferred Shares, Hydro One secured binding commitments for three bilateral two-year senior unsecured term credit facilities (Bilateral Credit Facilities) totalling $201 million. On October 15, 2020, these bilateral commitments were terminated upon receipt of the proceeds of Hydro One's $425 million long-term debt offering.

In April 2020, Hydro One Inc. filed a short form base shelf prospectus for its MTN Program, which has a maximum authorized principal amount of notes issuable of $4,000 million, expiring in May 2022. At December 31, 2020, $2,800 million remained available for issuance under the MTN Program prospectus.

On December 17, 2020, Hydro One Holdings Limited (HOHL), an indirect wholly-owned subsidiary of Hydro One, filed a short form base shelf prospectus (US Debt Shelf Prospectus) with securities regulatory authorities in Canada and the US, to replace a previous prospectus that expired in December 2020. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US$3,000 million of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending in January 2023. At December 31, 2020, no securities have been issued under the US Debt Shelf Prospectus.

Compliance

At December 31, 2020, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

Various ratings organizations review the Company's and Hydro One Inc.'s debt ratings from time to time. These ratings organizations may take various actions, positive or negative. The Company cannot predict what actions rating agencies may take in the future. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and 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.

On September 21, 2020, DBRS Limited (DBRS) assigned an issuer rating of "A" to the Company. DBRS also assigned a provisional rating of "A" to the Company's then proposed $425 million long-term debt issuance. Both trends are Stable. On September 22, 2020, S&P Global Ratings (S&P) assigned an issue-level rating of "BBB+" to the Company's $425 million long-term debt issuance.

At December 31, 2020, Hydro One's long-term credit ratings were as follows:

Rating Agency	Long-term Debt Rating
DBRS	A
S&P	BBB+

At December 31, 2020, 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	R-1 (low)	A (high)
Moody's	Prime-2	A3
S&P	A-1 (low)	A-

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated 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. The Company issues debt from time to time to refinance maturing debt and for general corporate purposes. The Company is therefore exposed to fluctuations in interest rates in relation to such issuances of debt. 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 2020, Hydro One made cash contributions of $57 million to its pension plan, compared to cash contributions of $61 million in 2019, and incurred $146 million in net periodic pension benefit costs, compared to $41 million incurred in 2019.

In September 2019, Hydro One filed a triennial actuarial valuation of its pension plan as at December 31, 2018. The next actuarial valuation will be performed no later than effective December 31, 2021. Hydro One estimates that total Company pension contributions for 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $59 million, $93 million, $107 million, $111 million, $111 million, $113 million, and $118 million, respectively. The estimated pension contributions for years beyond 2021 increased from amounts previously disclosed primarily due to a remeasurement of the Company's contributions at the end of 2020, reflecting a decrease in discount rate and an increase in the number of employees.

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:

As at December 31, 2020 (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	13,558	803	1,335	1,450	9,970
Long-term debt – interest payments	8,411	498	950	886	6,077
Short-term notes payable	800	800	—	—	—
Pension contributions[1]	712	59	200	222	231
Environmental and asset retirement obligations	160	34	46	24	56
Outsourcing and other agreements[2]	162	106	26	15	15
Lease obligations	90	16	25	22	27
Long-term software/meter agreement	13	8	3	2	—
Total contractual obligations	23,906	2,324	2,585	2,621	16,376
Other commercial commitments (by year of expiry)					
Operating Credit Facilities	2,550	—	—	2,550	—
Letters of credit[3]	196	194	2	—	—
Guarantees[4]	491	491	—	—	—
Total other commercial commitments	3,237	685	2	2,550	—

1 Contributions to the Hydro One Pension Fund are generally made one month in arrears. Company and employee contributions to the pension plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018.

2 In February 2021, Hydro One entered into an agreement for information technology services with Capgemini Canada Inc., which expires on February 29, 2024, and includes an option to extend for two additional one-year terms at Hydro One's discretion, resulting in an additional commitment of $143 million, which has not been reflected in the table above.

3 Letters of credit consist of $167 million in letters of credit related to retirement compensation arrangements, a $22 million letter of credit provided to the IESO for prudential support, $4 million in letters of credit to satisfy debt service reserve requirements, and $3 million in letters of credit for various operating purposes.

4 Guarantees consist of $484 million prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries, and guarantees totalling $7 million provided by Hydro One to the Minister of Natural Resources (Canada) relating to Ontario Charging Network LP (OCN LP) (OCN Guarantee). Ontario Power Generation Inc. (OPG) has provided a $2.5 million guarantee to Hydro One related to the OCN Guarantee.

Share Capital

The common shares of Hydro One are publicly traded on the Toronto Stock Exchange (TSX) under the trading symbol "H". Hydro One is authorized to issue an unlimited number of common shares. The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors (Board) 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 may consider relevant. At February 23, 2021, Hydro One had 597,611,787 issued and outstanding common shares.

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. The Company has two series of preferred shares authorized for issuance: the Series 1 preferred shares and Series 2 preferred shares. At February 23, 2021, the Company had no Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

On November 20, 2020, Hydro One exercised its option to redeem all of its 16,720,000 outstanding Preferred Shares in accordance with their terms. The Preferred Shares were redeemed at a price of $25.00 per share, plus all accrued and unpaid dividends up to, but excluding November 20, 2020, for an aggregate redemption price of $423 million, including $418 million for the Preferred Shares balance and $5 million for accrued dividends. The Preferred Shares were not exchangeable or convertible into the common shares of the Company and the redemption had no impact on the Province of Ontario's (Province) voting rights or ownership percentage of the outstanding common shares of Hydro One.

The number of additional common shares of Hydro One that would be issued if all outstanding awards under the share grant plans and the Long-term Incentive Plan (LTIP) were vested and exercised as at February 23, 2021 was 3,502,185.

Regulation

The OEB approves both the revenue requirements 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 with the OEB:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2020-2022	Transmission – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision received
B2M LP	2020-2024	Transmission – Revenue Cap	OEB decision received
HOSSM	2017-2026	Transmission – Revenue Cap	OEB decision received
NRLP	2020-2024	Transmission – Revenue Cap	OEB decision received
Peterborough Distribution	2020-2029	Distribution – Revenue Cap	OEB decision received[1]
Orillia Power	2020-2029	Distribution – Revenue Cap	OEB decision received[2]
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Peterborough Distribution	n/a	Acquisition	OEB decision received
Orillia Power	n/a	Acquisition	OEB decision received
Leave to Construct			
Power Downtown Toronto	n/a	Section 92	OEB decision pending[3]

1 Peterborough Distribution is under a 10-year deferred rebasing period for years 2020-2029, as approved in the OEB MAAD decision dated April 30, 2020.

2 Orillia Power is under a 10-year deferred rebasing period for years 2020-2029, as approved in the OEB MAAD decision dated April 30, 2020.

3 On October 27, 2020, Hydro One Networks filed a Leave to Construct application with the OEB seeking approval to upgrade five circuit kilometres of transmission cable facilities in the downtown Toronto area. These facilities are required to ensure that the area continues to receive a safe and reliable supply of electricity.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	Return on Equity (ROE) Allowed (A)	Rate Base Allowed (A)	Rate Application Status
Transmission				
Hydro One Networks	2020	8.52% (A)	$12,360 million (A)	Approved in April 2020
	2021	8.52% (A)	$12,927 million (A)	Approved in April 2020
	2022	8.52% (A)	$13,641 million (A)	Approved in April 2020
B2M LP	2020-2024	8.52% (A)	$488 million (A)	Approved in January 2020
HOSSM[1]	2017-2026	9.19% (A)	$218 million (A)	Approved in October 2016
NRLP	2020-2024	8.52% (A)	$118 million (A)	Approved in April 2020
Distribution				
Hydro One Networks	2020	9.00% (A)	$8,175 million (A)	Approved in March 2019
	2021	9.00% (A)	$8,514 million (A)	Approved in March 2019
	2022	9.00% (A)	$8,804 million (A)	Approved in March 2019

1 HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB MAAD decision dated October 13, 2016.

Electricity Rates Applications

Hydro One Networks – Transmission

Deferred Tax Asset

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission revenue requirements (Original Decision).

In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One 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 have resulted in an impairment of a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a motion to review and vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its reconsideration decision (DTA Decision) and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result, as at December 31, 2018, the Company recorded impairment charges relating to Hydro One Networks' distribution and transmission deferred income tax regulatory asset. Notwithstanding the recognition of the effects of the DTA Decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's DTA Decision. The appeal was heard on November 21, 2019.

On July 16, 2020, the Ontario Divisional Court rendered the ODC Decision on the Company's appeal of the OEB's DTA Decision. In its decision, the Ontario Divisional Court set aside the OEB's DTA Decision. The Ontario Divisional Court found that the OEB's DTA Decision was incorrect in law because the OEB had failed to apply the correct legal test. In its decision, the Ontario Divisional Court agreed with the submissions of Hydro One that the deferred tax asset should be allocated to shareholders in its entirety. However, the Ontario Divisional Court concluded that it does not have jurisdiction to substitute its own decision for that of the OEB and, with clear directions as to what the OEB's decision must be, ordered that the matter be returned to the OEB. The OEB did not file a notice for leave to appeal the ODC Decision to the Ontario Court of Appeal by the required deadline of July 31, 2020.

In connection with the ODC Decision, the Company recorded a reversal of the previously recognized impairment charge of Hydro One Networks' distribution and transmission deferred income tax regulatory asset in its financial statements for the year ended December 31, 2020. The reversal of the previously recognized impaired charge included the regulatory asset relating to the cumulative deferred tax asset amounts shared with ratepayers (deferred tax asset sharing) up to and including June 30, 2020 by Hydro One Networks' distribution and transmission segments of $58 million and $118 million, respectively. Hydro One recognized deferred income tax regulatory assets of $504 million and $673 million for Hydro One Networks distribution and transmission segments, respectively, and associated deferred income tax liability of $310 million. The Company also recorded an increase in net income of $867 million as deferred income tax recovery during the year ended December 31, 2020.

On September 21, 2020, the Ontario Divisional Court issued its final order (ODC Order) with respect to the ODC Decision. Following the ODC Order, on October 2, 2020, the OEB issued a procedural order to implement the direction of the Ontario Divisional Court and required Hydro One to submit its proposal for the recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2022 period. The proceeding on this matter is currently ongoing, and a decision is anticipated in the first half of 2021.

2020-2022 Transmission Rates

On April 23, 2020, the OEB rendered its decision on Hydro One Networks' 2020-2022 transmission rate application (2020-2022 Transmission Decision). On July 16, 2020, the OEB issued its final rate order for the 2020-2022 transmission rates approving a revenue requirement of $1,630 million, $1,701 million and $1,772 million for 2020, 2021 and 2022, respectively. On July 30, 2020, the OEB issued its decision for Uniform Transmission Rates (UTRs). The 2020 UTRs that were put in place on an interim basis on January 1, 2020 continued for the remainder of 2020 in light of the COVID-19 pandemic. On December 17, 2020, the OEB issued its decision and order setting the final 2021 UTRs effective January 1, 2021, which included the approval of a two-year disposition period for Hydro One Network's 2020 foregone revenue including interest, beginning on January 1, 2021.

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.

On March 7, 2019, the OEB rendered its decision on Hydro One Networks' 2018-2022 distribution rate application (2018-2022 Distribution Decision). In accordance with the 2018-2022 Distribution Decision, as well as the DTA Decision, the Company filed its draft rate order reflecting updated revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022. On June 11, 2019, the OEB approved the rate order confirming these updated revenue requirements, which include impacts of both the 2018-2022 Distribution Decision and the DTA Decision.

On March 26, 2019, the Company filed a motion to review and vary the OEB's decision as it relates to rates revenue requirement recovery of employer pension costs. Concurrently, the Company filed an appeal with the Ontario Divisional Court. The appeal was held in abeyance pending the outcome of the motion made before the OEB. In 2019, the Company reflected a portion of pension costs incurred in the Hydro One Networks' distribution Pension Cost Differential regulatory account, pending the outcome of the motion before the OEB. On December 19, 2019, the OEB affirmed its earlier decision with respect to recovery of the revenue requirement associated with pension costs. As a result, Hydro One derecognized the portion relating to pension costs charged to operations as a reversal of revenues of $13 million, and also transferred $37 million to property, plant and equipment and intangible assets, which represents the portion attributable to capital expenditures.

Hydro One Remote Communities

On April 16, 2020, the OEB approved a 2% increase to Hydro One Remote Communities' 2019 base rates for new rates effective May 1, 2020, with a deferred implementation date of November 1, 2020 due to COVID-19. On October 8, 2020, the OEB authorized Hydro One Remote Communities to implement a rate rider for the recovery of foregone revenues resulting from postponing rate implementation. The rider is effective until April 30, 2021. On November 3, 2020, Hydro One Remote Communities filed an application with the OEB seeking approval for a 2% increase to 2020 base rates, effective May 1, 2021, which was subsequently updated to 2.2% in accordance with the OEB's 2021 inflation parameters for electricity distributors issued on November 9, 2020.

Hydro One Remote Communities is fully financed by debt and is operated as a break-even entity with no ROE.

NRLP

On October 25, 2019, NRLP filed its revenue cap incentive rate application for 2020-2024. On December 19, 2019, the OEB approved NRLP's proposed 2020 revenue requirement of $9 million on an interim basis effective January 1, 2020. On February 12, 2020, all parties reached a full settlement agreement on all issues, accepting the 2020 base costs and the 2019 incurred costs as presented. The settlement included a 50% reduction to the inflation component and a 0.6% capital adjustment factor to account for a lowering rate base value. On March 6, 2020, the settlement agreement was filed for the OEB's approval, and on April 9, 2020, the OEB approved the settlement agreement.

B2M LP

On July 31, 2019, B2M LP filed a transmission rate application for 2020-2024. A settlement agreement was reached on December 9, 2019. The settlement accepted all of B2M LP's cost submissions, including additional reliability reporting and a capital adjustment (reduction) factor of 0.6% to account for the decreasing rate base value. On January 16, 2020, the OEB approved the settlement agreement, including a 2020 base revenue requirement of $33 million (updated for lower ROE and interest rates), and a revenue cap escalator index for 2021 to 2024.

MAAD Applications

Peterborough Distribution MAAD Application

On April 30, 2020, the OEB issued its decision approving Hydro One's application to acquire the business and distribution assets of Peterborough Distribution, from the City of Peterborough. See section "Other Developments" for additional information.

Orillia Power MAAD Application

On April 30, 2020, the OEB issued its decision approving Hydro One's application to acquire Orillia Power from the City of Orillia. See section "Other Developments" for additional information.

Hydro One Transmission Licence Amendment

On December 17, 2020, the Province issued a directive to the OEB to amend Hydro One Networks' electricity transmission licence to include a requirement that Hydro One proceed to develop and seek all approvals necessary related to the Leamington Area Transmission Reinforcement project in order to keep the project on schedule to meet the IESO's recommended in-service date. The OEB amended Hydro One's licence on December 23, 2020. See section "Major Transmission Capital Investment Projects" for further details on Leamington Area Transmission Reinforcement project.

Other Developments

COVID-19

Throughout the COVID-19 pandemic, the Company's decisions and actions have continuously been guided by two priorities: to protect Hydro One's employees and to maintain the safe and reliable supply of electricity to Hydro One's customers. Since the onset of the COVID-19 pandemic in March 2020, Hydro One employees have worked extremely hard to overcome the challenges that COVID-19 has presented. Over the course of the last 11 months Hydro One has been extremely successful in achieving its priorities as it was able to return to full capacity within its field operations after a short stand-down of its workforce and has also experienced very few suspected cases of workplace transmission of the COVID-19 virus to date.

The Company continues to monitor and adhere to guidance provided by the Province and public health experts in an effort to ensure employee, customer and public safety. After focusing on high priority and essential work at the onset of pandemic, the Company returned substantially all of its field crews to work, where it was safe to do so, in the second quarter. In the third quarter of 2020, the Company implemented enhanced safety procedures within its office locations across the province to reopen its offices to a small portion of its office and administrative staff. However, the Company has since reinstated its business continuity procedures, including work from home protocols for all office staff, in light of the Provincial Stay at Home Order announced in December 2020. The Company's focus remains on ensuring that its teams are equipped to operate safely as the Company continues to advance work on capital and operating work programs.

As part of the Company's continued commitment to customers, Hydro One implemented a number of customer relief measures at the outset of the pandemic to assist customers impacted by COVID-19. These measures included (i) the Pandemic Relief Fund, (ii) financial assistance and increased payment flexibility, (iii) extending the Winter Relief program, and (iv) the temporary suspension of late fees until December 31, 2020. In January 2021, the Company announced a Small Business Pandemic Relief Program to provide financial assistance and payment flexibility to its small business customers.

In addition to the impact on the Company's operations noted above, the COVID-19 pandemic had the following impact on Hydro One's financial results for the twelve months ended December 31, 2020:

- While electricity consumption and demand can be impacted by numerous variables, it is difficult to determine the exact impact that the COVID-19 pandemic has had on peak demand and customer consumption over this period with any level of precision.
- The temporary deferral of operating and capital work at the onset of the pandemic resulted in the recognition of costs associated with the stand-down and stranded labour costs of the Company's casual workforce in the second and third quarters of 2020.
- The pandemic resulted in the prolonged temporary closures of businesses across Ontario, which also impacted employment rates locally. As a result of the financial and economic impact of the COVID-19 pandemic on residents and business alike, the Company has recorded a $14 million allowance for doubtful accounts as of December 31, 2020. While there have been no significant permanent losses incurred to date, management continues to believe that there remains increased risk associated with the ultimate collection of billed energy consumption.
- Lost revenues associated with the ongoing customer relief efforts noted above have approximated $10 million.
- The COVID-19 pandemic resulted in no significant impacts on the Company's critical accounting estimates and judgments, and internal controls over financial reporting.

In March 2020, the OEB issued initial guidance for the tracking of incremental costs and lost revenues related to the COVID-19 pandemic. In accordance with OEB updates issued in August 2020, the Company has established five deferral accounts to track costs associated with (i) Billing and System Changes as a result of the Emergency Order Regarding Time-Of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Foregone Revenues from Postponing Rate Implementation, (iv) incremental Bad Debt, and (v) Other Incremental Costs.

In May 2020, the OEB commenced a consultation on the COVID-19 emergency deferral accounts to assist in its development of new accounting guidance related to the accounts as well as filing requirements for the review and disposition of these accounts. In

September 2020, the OEB engaged external consultants to commission certain reports to assist the OEB in its preparation of an OEB staff proposal (Staff Proposal) which was issued on December 16, 2020. In its proposal, OEB staff suggested that utilities must demonstrate a financial need and meet certain criteria to be eligible to seek recovery of COVID-19 related costs and lost revenues. Stakeholders were provided an opportunity to submit feedback on the Staff Proposal in January 2021, and it is currently expected that the OEB will issue final guidance sometime in the first half of 2021. Although the consultation is ongoing and the Staff Proposal is subject to change, based on the Company's current interpretation of the Staff Proposal, it appears that Hydro One is unlikely to qualify for any significant recovery of COVID-19 related incremental costs or lost revenues. As a result, during the three months ended December 31, 2020, the Company has reversed the recognition of the regulatory asset associated with the aforementioned incremental bad debt provision recognized in the first quarter of 2020, and has recognized this expense in OM&A in the period.

As at December 31, 2020, the Company is tracking approximately $60 million in the deferral accounts noted above in accordance with the guidelines published by the OEB in the Staff Proposal. The Company has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory assets.

Looking ahead, it is very difficult to determine or estimate the exact impacts of COVID-19 on Hydro One's operations as it will be largely dependent on the duration of the pandemic and severity of the measures implemented to combat this virus. Hydro One continues to take the necessary steps to mitigate the impact of COVID-19 on the Company's operations.

The COVID-19 pandemic subjects the Company to additional risks and uncertainties. Please see section "Risk Management and Risk Factors – Infectious Disease Risk" for a discussion of the potential impacts of a pandemic such as COVID-19 on Hydro One.

Federal and Ontario Budgets

2019 Federal and Ontario Budgets

Certain 2019 federal and Ontario budget measures enacted in 2019 provide certain time-limited investment incentives permitting Hydro One to deduct Accelerated CCA of up to three times the first-year rate for eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028. The 2019 enactment of the Accelerated CCA has resulted in a temporary reduction in the Company's ETR for the years ended December 31, 2019 and 2020 with the recognition of a tax regulatory liability relating to the Accelerated CCA impact (Tax Rule Change Variance) that has not been reflected in the OEB approved rates. The timing of the disposition of the Tax Rule Change Variance is subject to OEB approval, and may have a material impact on Hydro One's future cash flows in the near term.

Hydro One currently expects the Company's ETR to remain in the range of 6% to 13% over the next five years, subject to changes arising from the timing and manner in which the OEB seeks to implement the ODC Decision.

Ontario Budget

In November 2020, the Province released its 2020 Ontario Budget: Ontario's Action Plan: Protect, Support, Recover (Ontario Budget) which included a rate mitigation plan to help certain business and industrial customers. Starting on January 1, 2021, a portion of non-hydro renewable energy contracts (i.e., wind, solar, bioenergy) will be funded by the Province and not ratepayers. According to the Ontario Budget, this represents approximately 25% of the current cost of the Global Adjustment. This reduction in the Global Adjustment will not benefit regulated price plan customers (households, farms, small businesses), who will instead continue to be protected by means of the Ontario Electricity Rebate program. These changes impact purchased power costs which are recovered in rates, and as such have no impact on the Company's net income.

Exemptive Relief

Disclosure of Ownership by the Province

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) OPG (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.

US GAAP

On March 27, 2018, Hydro One was granted exemptive relief by securities regulators in each province and territory of Canada which allows Hydro One to continue to report its financial results in accordance with US GAAP (Exemptive Relief). The Exemptive Relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of Hydro One's financial year that commences after Hydro One ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation. In late January 2021, the IASB published an Exposure Draft – *Regulatory Assets and Liabilities* (ED). The effective date for mandatory application of the eventual final standard is not yet determinable and the Company continues to monitor the developments of the ED and determine the potential impacts to the Company's financial statements.

Hydro One Limited is also permitted to report its financial results in accordance with US GAAP by virtue of being, and for so long as it remains, a SEC issuer (within the meaning of National Instrument 52-107 – Acceptable Accounting Principles and Auditing Standards). There can be no assurance that Hydro One Limited will remain a SEC issuer indefinitely.

NRLP

In 2018, Hydro One entered into an agreement with the First Nations Partners, wherein a noncontrolling equity interest in Hydro One's limited partnership, NRLP, would be made available for purchase at fair value by the First Nations Partners. On September 12, 2019, the OEB granted NRLP a transmission licence and granted Hydro One Networks leave to sell the applicable Niagara Line assets to NRLP.

On September 18, 2019, the applicable Niagara Line assets were transferred from Hydro One Networks to NRLP for $119 million and operation of the line was contracted to Hydro One Networks. This transfer was financed with 60% debt ($71 million) and 40% equity ($48 million). The cash payment of $71 million was financed by debt sourced by NRLP from a Hydro One subsidiary, and the $48 million equity comprised partnership units issued by NRLP to Hydro One Networks. Subsequently, on the same date, Hydro One Networks sold to the Six Nations of the Grand River Development Corporation and, through a trust, to the Mississaugas of the Credit First Nation a 25.0% and 0.1%, respectively, equity interest in NRLP partnership units for total consideration of $12 million, representing the fair value of the equity interest acquired.

On January 31, 2020, the Mississaugas of the Credit First Nation purchased an additional 19.9% equity interest in NRLP partnership units from Hydro One Networks for total cash consideration of $9 million. Following this transaction, Hydro One's interest in the equity portion of NRLP partnership units was reduced to 55%, with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation owning 25% and 20%, respectively, of the equity interest in NRLP partnership units.

Building Transit Faster Act

On February 18, 2020, the Ministry of Transportation introduced Bill 171, to enact the *Building Transit Faster Act, 2020* (Transit Act), relating to four priority transit projects in the Toronto area. The Transit Act was passed on July 8, 2020. The Transit Act poses commitments on utilities, including Hydro One, to relocate infrastructure to allow the timely construction of the transit projects. Metrolinx, the builder of the transit projects, and Hydro One must work together on a notice that agrees to the timing of when the relocation work must be completed. If Hydro One is non-compliant, Metrolinx can file an application with the Ontario Superior Court of Justice, where a judge can either order Hydro One to comply or authorize Metrolinx to carry out the work, or impose a monetary penalty on Hydro One. On July 8, 2020, the *Ontario Energy Board Act, 1998* (OEB Act) was accordingly amended to prohibit a utility from recovering the monetary penalty in rates. On October 22, 2020, Bill 222, *An Act to Amend Various Acts in Respect of Transportation-Related Matters* passed first reading. Bill 222 includes amendments to the Transit Act so that the Transit Act would also apply to "any other prescribed provincial transit project" in addition to the four priority transit projects in the Toronto area. The Bill 222 received Royal Assent on December 8, 2020.

Peterborough Distribution Acquisition

On August 1, 2020, Hydro One completed the acquisition of the business and distribution assets of Peterborough Distribution, an electricity distribution company located in east central Ontario, from the City of Peterborough, for a purchase price of $104 million, including the assumption of agreed upon liabilities and closing adjustments.

Orillia Power Acquisition

On September 1, 2020, Hydro One completed the acquisition of Orillia Power, an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for a purchase price of $28 million, including closing adjustments.

Sustainability Report

The Hydro One 2019 Sustainability Report entitled "For the Possibilities of Tomorrow" is available on the Company's website at www.hydroone.com/sustainability.

By using its corporate strategy as the roadmap, Hydro One is more focused than ever on being customer-driven, sustainable, safe and efficient. The 2019 Sustainability Report highlights the Company's progress on operating safely, managing emissions, building relationships with communities and achieving a more diverse workforce. As the Company carries out its mission to energize life for people and communities, it does so with an understanding of the responsibility it has to build a more sustainable world.

The social elements of sustainability are key to ensuring affordability for Hydro One's customers, removing racism and building an inclusive culture, all while adapting the Company's business model to support a greener economy. Going forward, Hydro One is focused on reducing its environmental footprint; strengthening its Indigenous and community partnerships; and diversifying talent across its workforce. No matter how challenging the time, the success of the Company's long-term performance depends on incorporating sustainability into all aspects of its business.

Hydro One is committed to operating safely in an environmentally and socially responsible manner and to partnering with its customers and community stakeholders to build a brighter future for all.

Termination of the Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation. In January 2019, Hydro One and Avista Corporation announced that the companies mutually agreed to terminate the Merger agreement. The following amounts related to the termination of the Merger agreement were recorded by the Company during the first quarter of the year ended December 31, 2019.

- $138 million (US$103 million) for payment of the Merger termination fee recorded in operation, maintenance and administration costs;
- $22 million financing charges, due to reversal of previously recorded unrealized gains upon termination of the deal-contingent foreign-exchange forward contract (Foreign-Exchange Contract);
- redemption of $513 million convertible debentures and payment of related interest of $7 million; and
- $24 million financing charges, due to derecognition of the deferred financing costs related to convertible debentures.

Hydro One Board of Directors and Executive Officers

Board of Directors

Effective May 7, 2020, Anne Giardini resigned from the Company's Board. On July 23, 2020, Stacey Mowbray was appointed to the Board.

Executive Officers

Effective January 2, 2020, David Lebeter was appointed as the Chief Operating Officer of Hydro One and Hydro One Inc.

On September 1, 2020, Saylor Millitz-Lee, Executive Vice President and Chief Human Resources Officer, retired, and effective September 28, 2020, Megan Telford was appointed as the new Chief Human Resources Officer.

On November 1, 2020, Darlene Bradley, Chief Safety Officer, retired, and Lyla Garzouzi was subsequently appointed as the new Chief Safety Officer, effective the same date.

Hydro One Work Force

At December 31, 2020, Hydro One had a skilled and flexible workforce of approximately 6,000 regular employees and 2,100 non-regular employees province-wide, comprising 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 contingent workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly use 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, 2020:

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU)[1, 2]	3,607	494	4,101
Society of United Professionals (Society)[2]	1,555	39	1,594
Canadian Union of Skilled Workers (CUSW) and construction building trade unions	—	1,563	1,563
Total employees represented by unions	5,162	2,096	7,258
Management and non-represented employees	788	39	827
Total employees[3]	5,950	2,135	8,085

1 Includes 398 non-regular "hiring hall" employees covered by the PWU agreement.

2 In February 2021, Hydro One has finalized agreements with the PWU, the Society, Inergi LP, and Capgemini Canada Inc. to transfer approximately 250 represented Inergi LP employees to Hydro One by January 2022.

3 The average number of Hydro One employees in 2020 was approximately 8,700, consisting of approximately 5,900 regular employees and approximately 2,800 non-regular employees.

Collective Agreements

The collective agreement with the PWU (for classifications other than Customer Service Operations (CSO)) expired on March 31, 2020. The collective agreement with the PWU for CSO was set to expire on September 30, 2019; however, it was extended to allow for bargaining at the same time as the non-CSO agreement. On July 17, 2020, Hydro One and the PWU reached tentative deals for both collective agreements. The PWU ratified the CSO and non-CSO collective agreements on September 4, 2020 and October 6, 2020, respectively. The new CSO agreement expires on September 30, 2022, and the new non-CSO collective agreement expires on March 31, 2023.

The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA). EPSCA is an employers' association of which Hydro One is a member. The EPSCA construction collective agreements, which bind Hydro One, expired on April 30, 2020. Ratified five-year renewal collective agreements, covering May 1, 2020 to April 30, 2025, have been reached with all nineteen building trades.

The current collective agreement with the Society expires on March 31, 2021. In February 2021, Hydro One and the Society commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Stock-based Compensation

The Company granted awards under its LTIP, consisting of Performance Share Units (PSUs), Restricted Share Units (RSUs), and Stock Options. At December 31, 2020 and 2019, the following LTIP awards were outstanding:

December 31 (number of units)	**2020**	2019
PSUs	**111,920**	171,344
RSUs	**139,730**	206,993
Stock Options	**108,710**	403,550

Non-GAAP Measures

FFO, basic and diluted Adjusted EPS, adjusted net income, revenues, net of purchased power, and distribution 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.

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, management believes that FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 (millions of dollars)	**2020**	2019
Net cash from operating activities	**2,030**	1,614
Changes in non-cash balances related to operations	**(180)**	(55)
Preferred share dividends	**(18)**	(18)
Distributions to noncontrolling interest	**(2)**	(9)
FFO	**1,830**	1,532

Adjusted Net Income and Adjusted EPS

The following adjusted net income, and basic and diluted Adjusted EPS have been calculated by management on a supplementary basis which adjusts net income under US GAAP for income and costs related to the Merger and impacts related to the ODC Decision and the OEB's DTA Decision on Hydro One Networks' distribution and transmission businesses. Adjusted net income and Adjusted EPS are used internally by management to assess the Company's performance and are considered useful because they exclude the impacts of the Merger as well as the ODC Decision and the OEB's DTA Decision as noted above. Adjusted net income and Adjusted EPS provide users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

Year ended December 31 (millions of dollars, except number of shares and EPS)	**2020**	2019	2018
Net income (loss) attributable to common shareholders	**1,770**	778	(89)
Impacts related to the Merger:			
OM&A – Merger-related costs (before tax)	**–**	138	11
Financing charges – Merger-related costs (before tax)	**–**	31	58
Financing charges – loss (gain) on Foreign-Exchange Contract (before tax)	**–**	22	(25)
Tax impact	**–**	(51)	(15)
Merger-related impacts (after tax)	**–**	140	29
Impacts related to the ODC Decision	**(867)**	—	867
Adjusted net income attributable to common shareholders	**903**	918	807
Weighted average number of shares			
Basic	**597,421,127**	596,437,577	595,756,470
Effect of dilutive stock-based compensation plans	**2,497,161**	2,410,860	2,147,473
Diluted	**599,918,288**	598,848,437	597,903,943
Adjusted EPS			
Basic	**$ 1.51**	$ 1.54	$ 1.35
Diluted	**$ 1.51**	$ 1.53	$ 1.35

Quarter ended (millions of dollars, except number of shares and EPS)	Dec 31, 2020	Sep 30, 2020	Jun 30, 2020	Mar 31, 2020
Net income attributable to common shareholders	161	281	1,103	225
Impacts related to the ODC Decision	—	—	(867)	—
Adjusted net income attributable to common shareholders	161	281	236	225
Weighted-average number of shares				
Basic	597,588,309	597,557,787	597,551,514	596,983,560
Effect of dilutive stock-based compensation plans	2,586,310	2,362,569	2,423,441	2,663,999
Diluted	600,174,619	599,920,356	599,974,955	599,647,559
Adjusted EPS				
Basic	$ 0.27	$ 0.47	$ 0.39	$ 0.38
Diluted	$ 0.27	$ 0.47	$ 0.39	$ 0.38

Quarter ended (millions of dollars, except number of shares and EPS)	Dec 31, 2019	Sep 30, 2019	Jun 30, 2019	Mar 31, 2019
Net income attributable to common shareholders	211	241	155	171
OM&A – Merger-related costs (before tax)	—	—	—	138
Financing charges – Merger-related costs (before tax)	—	—	—	31
Financing charges – loss on Foreign-Exchange Contract (before tax)	—	—	—	22
Tax impact	—	—	—	(51)
Impacts related to the Merger (after tax)	—	—	—	140
Adjusted net income attributable to common shareholders	211	241	155	311
Weighted-average number of shares				
Basic	596,670,374	596,605,054	596,503,988	595,961,260
Effect of dilutive stock-based compensation plans	2,564,789	2,420,792	2,442,181	2,354,970
Diluted	599,235,163	599,025,846	598,946,169	598,316,230
Adjusted EPS				
Basic	$ 0.35	$ 0.40	$ 0.26	$ 0.52
Diluted	$ 0.35	$ 0.40	$ 0.26	$ 0.52

Revenues, Net of Purchased Power

Revenues, net of purchased power is defined as revenues less the cost of 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)	**2020**	2019
Revenues	**7,290**	6,480
Less: Purchased power	**3,854**	3,111
Revenues, net of purchased power	**3,436**	3,369

Year ended December 31 (millions of dollars)	**2020**	2019
Distribution revenues	**5,507**	4,788
Less: Purchased power	**3,854**	3,111
Distribution revenues, net of purchased power	**1,653**	1,677

Quarter ended (millions of dollars)	Dec 31, 2020	Sep 30, 2020	Jun 30, 2020	Mar 31, 2020	Dec 31, 2019	Sep 30, 2019	Jun 30, 2019	Mar 31, 2019
Revenues	1,867	1,903	1,670	1,850	1,715	1,593	1,413	1,759
Less: Purchased power	1,046	993	808	1,007	914	737	653	807
Revenues, net of purchased power	821	910	862	843	801	856	760	952

Quarter ended (millions of dollars)	Dec 31, 2020	Sep 30, 2020	Jun 30, 2020	Mar 31, 2020	Dec 31, 2019	Sep 30, 2019	Jun 30, 2019	Mar 31, 2019
Distribution revenues	1,457	1,410	1,201	1,439	1,298	1,140	1,029	1,321
Less: Purchased power	1,046	993	808	1,007	914	737	653	807
Distribution revenues, net of purchased power	411	417	393	432	384	403	376	514

Adjusted Income Tax Expense and Adjusted ETR

The following adjusted income tax expense and adjusted ETR has been calculated by management on a supplementary basis which adjusts ETR for income and costs related to the Merger and impacts related to the ODC Decision. Adjusted ETR is used internally by management to assess the Company's income tax impacts and is considered useful because it excludes the impacts of the Merger and the ODC Decision. Adjusted ETR provides users with a comparative basis to evaluate the income tax impacts on the Company compared to prior year.

Year ended December 31 (millions of dollars)	**2020**	2019
Income before income tax expense	**1,011**	796
OM&A – Merger-related costs (before tax)	**—**	138
Financing charges – Merger-related costs (before tax)	**—**	31
Financing charges – loss on Foreign-Exchange Contract (before tax)	**—**	22
Impacts related to the Merger	**—**	191
Adjusted income before income tax expense	**1,011**	987
Income tax (recovery)	**(785)**	(6)
Impacts related to the ODC Decision	**(867)**	—
Impacts related to the Merger	**—**	(51)
	(867)	(51)
Adjusted income tax expense	**82**	45
Adjusted ETR	**8.1%**	4.6%

Related Party Transactions

The Province is a shareholder of Hydro One with approximately 47.3% ownership at December 31, 2020. The IESO, OPG, Ontario Electricity Financial Corporation (OEFC), and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Ministry of Energy. OCN LP is a joint-venture limited partnership between a subsidiary of Hydro One and OPG. The following is a summary of the Company's related party transactions during the years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)

Related Party	Transaction	**2020**	2019
Province	Dividends paid[1]	**301**	288
IESO	Power purchased	**2,506**	1,808
	Revenues for transmission services	**1,717**	1,636
	Amounts related to electricity rebates	**1,588**	692
	Distribution revenues related to rural rate protection	**242**	240
	Distribution revenues related to the supply of electricity to remote northern communities	**35**	35
	Funding received related to CDM programs	**26**	42
OPG[2]	Power purchased	**6**	8
	Revenues related to provision of services and supply of electricity	**8**	9
	Capital contribution received from OPG	**3**	—
	Costs related to the purchase of services	**3**	1
OEFC	Power purchased from power contracts administered by the OEFC	**1**	2
OEB	OEB fees	**9**	9
OCN LP[3]	Investment in OCN LP	**2**	2

1 On November 20, 2020, Hydro One redeemed the Preferred Shares held by the Province. See section Share Capital.

2 OPG has provided a $2.5 million guarantee to Hydro One related to the OCN Guarantee. See Other Obligations – Summary of Contractual Obligations and Other Commercial Commitments for details related to the OCN Guarantee.

3 OCN LP owns and operates electric vehicle fast charging stations across Ontario, under the Ivy Charging Network brand.

Risk Management and Risk Factors

Hydro One is subject to numerous risks and uncertainties. Critical to Hydro One's success is the identification, management, and to the extent possible, mitigation of these risks. Hydro One's Chief Risk Officer has accountability for the Company's Enterprise Risk Management (ERM) program, which assists decision-makers throughout the organization with the management of key business risks, including new and emerging risks and opportunities.

The material risks relating to Hydro One and its business that the Company believes would be the most likely to influence an investor's decision to purchase Hydro One's securities are set out in the risk factors below. These risks, if they materialize, could have a materially adverse effect on the Company or its business, financial condition, or results of operations. This list is not a comprehensive list of all the risks to the Company, and the actual effect of any of the risks cited below could be materially different from what is described below. Additionally, other risks may arise or risks currently not considered material may become material in the future.

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 the ability to recover in rates costs actually incurred, may materially adversely affect: Hydro One's transmission and 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, the Company may incur costs before having an approved revenue requirement and cash flows could be impacted. The Company is also subject to the risk that the OEB could change the regulatory treatment of certain costs which may affect the Company's accounting treatment of and ability to recover such costs.

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 recover any significant difference between forecast and actual expenses and to obtain associated regulatory approvals to recover the difference 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 conditions, changes in service territory, 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 CDM programs whose results exceed forecasted expectations.

Risks Relating to Other Applications to the OEB

Hydro One may face increased competition with other transmitters for opportunities to build new, large-scale transmission facilities in Ontario. The Company is subject to the risk that it will not be selected to build new transmission in Ontario, which could impair growth, disrupt operations and/or development, or have other adverse impacts. 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, that the Company may not be selected to build new transmission as part of the competitive process, or that unfavourable conditions will be imposed by the OEB.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the rate-setting models and methodology for the transmission and distribution businesses. Changes to the application type, filing requirements, rate-setting model or methodology, or revenue requirement determination may have a material negative impact on Hydro One's revenue and net income. For example, 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. Similarly, the OEB is currently considering other utility remuneration models, and any such change could affect Hydro One's revenue and net income.

The OEB's Custom Incentive Rate-setting model requires that the term of a custom rate application be for multi-year periods. 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.

When rates are set for a multi-year period, including under a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the multi-year period, 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 in rates, capital expenditures require the approval of the OEB. There can be no assurance that all capital expenditures, including any imposed by or resulting from government or regulatory bodies, incurred by Hydro One will be approved by the OEB. For example, capital cost overruns, unexpected capital expenditures in maintaining or improving the Company's assets, unexpected costs as a result of proposed legislation, including that relating to the expansion of broadband service in Canada, may not be recoverable in transmission or distribution rates. To the extent possible, Hydro One aims to mitigate this risk by ensuring expenditures are reasonable and prudent, and also by seeking from the regulator clear policy direction on cost responsibility, and by obtaining 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.

Risk of Recoverability of Total Compensation Costs
Hydro One manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits (OPEBs), subject to restrictions and requirements imposed by the collective bargaining process and legislative requirements. Any element of total compensation costs which is disallowed in whole or part by the OEB and therefore 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. The OEB Act prohibits Hydro One from recovering specified executive compensation costs in its rates.

The Company provides OPEBs, including workers compensation benefits and long-term disability benefits to qualifying employees. 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 or otherwise adjusted the basis of recovery for OPEB costs, 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, and the Company might not be able to recover some costs. 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.

Risks Relating to Regulatory Treatment of Deferred Tax Asset
As a result of leaving the payments in lieu of corporate income taxes (PILs) regime and entering the federal tax regime in connection with the 2015 initial public offering (IPO) of the Company, Hydro One recorded additional deferred tax assets 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. At the time of the IPO, the Company determined the tax savings derived from the additional deferred tax assets should accrue to the shareholders of Hydro One Limited. The OEB's September 28, 2017 Original Decision (see details above in "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission") altered Hydro One's allocation of the tax savings derived from the additional deferred tax assets and determined that a portion of the tax savings should accrue to ratepayers. In October 2017, the Company filed a motion to review and vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal) which was stayed pending the outcome of the Motion. In both cases, the Company's position was that the OEB made errors of fact and law in its determination of the allocation of the tax savings between shareholders and ratepayers.

On March 7, 2019, the OEB issued a decision upholding its Original Decision on the handling of the deferred tax asset. Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. Based on these decisions, the Company recognized a total one-time $867 million decrease to net income. On April 5, 2019, the Company filed a motion to commence a new appeal with respect to the OEB's deferred tax asset decision. The appeal was heard on November 21, 2019, and on July 16, 2020, the Ontario Divisional Court rendered its decision, setting aside the decision of the OEB and ordered the matter be returned to the OEB to correct the errors identified and made the appropriate tax savings allocation. If the OEB again fails to make the appropriate tax savings allocation, it could have a material adverse effect on the Company.

Risks Relating to Government Action
The Province is, and is likely to remain, the largest shareholder in Hydro One Limited. The Province may be in a position of conflict from time to time as a result of being an investor in Hydro One Limited and also being a government actor setting broad policy objectives in the electricity industry. Government actions may not be in the interests of the Company or investors.

Governments may pass legislation or issue regulations at any time, including legislation or regulation impacting Hydro One, which could have potential material adverse effects on Hydro One and its business. Such government actions may include, but are not limited to, legislation, regulation, directives or shareholder action intended to reduce electricity rates, place constraints on compensation, or affect the governance of Hydro One. Such government actions could adversely affect the Company's financial condition and results of operations, as well as public opinion and the Company's reputation. Government action may also hinder Hydro One's ability to pursue its strategy and/or objectives.

Additionally, involvement by the Province in placing constraints on executive compensation (through the compensation framework implemented as a result of the *Hydro One Accountability Act, 2018*) may inhibit the Company's ability to attract and retain qualified executive talent, which may also impact the Company's performance, strategy and/or objectives. The failure to attract and retain qualified executives could have a material adverse effect on the Company.

Government action may also impact the Company's credit ratings as the Company's credit ratings reflect, in part, the rating agencies' assessment of government involvement in the business of Hydro One. The Company cannot predict what actions rating agencies may take in the future, positive or negative, including in response to government action or inaction relating to or impacting Hydro One. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and 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.

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, or 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 (land traditionally occupied or used by a First Nation, Métis or Inuit group) and are increasingly willing to assert their claims through the courts, tribunals, or direct action. These claims, and/or the settlement or resolution 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, including communities with a traditional governance model not recognized under the *Indian Act*, 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, 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 with the First Nation, 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.

Executive Recruitment and Retention Risk

Involvement by the Province relating to executive compensation, and Hydro One executive compensation constraints flowing from the *Hydro One Accountability Act, 2018,* may inhibit the Company's ability to attract and retain qualified executive talent. The Company's strategy is tied to its ability to continue to attract and retain qualified executives. The failure to attract and retain qualified executives could have a material adverse effect on the Company.

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 "– Environment Risk" and "– Health and Safety 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. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with applicable reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The 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 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 reduce Hydro One's revenue, or 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, and any other potentially catastrophic events. The Company's facilities may not withstand occurrences of these types in all circumstances.

The Company could also be subject to claims for damages from events which may be proximately connected with the Company's assets (for example, forest fires), claims for damages caused by its failure to transmit or distribute electricity, costs related to ensuring its continued ability to transmit or distribute electricity or costs related to information or cyber security.

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 the Company's other assets and for damage claims and cyber security claims, such insurance coverage may have deductibles, limits and/or exclusions that may still expose the Company to material losses. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas.

In the event that the Company is unable to recover such costs, this could have a material adverse effect on the Company.

Infectious Disease Risk
An outbreak of infectious disease, in the form of an epidemic, a pandemic (such as COVID-19), or a similar public health threat, could materially adversely impact the Company. The extent of any such adverse impact on the Company is uncertain, and may depend on the length and severity of any such infectious disease outbreak, any resultant government regulations, guidelines and actions, and any related adverse changes in general economic and market conditions. Such an outbreak, the resultant government regulations, guidelines and actions, and related adverse changes in general economic and market conditions could impact, in particular: the Company's operations and workforce, including its ability to complete planned operating and capital work programs within scope and budget; certain financial obligations of the Company, including pension contributions and other post-retirement benefits, as a result of changes in prevailing market conditions; the Company's expected revenues; reductions in overall electricity consumption and load, both short term and long term; overdue accounts and bad debt increases as a result of changes in the ability of the Company's customers to pay; liquidity and the Company's ability to raise capital; the Company's ability to pay or increase dividends; the timing of increased rates; the Company's ability to recover incremental costs and lost revenues linked to the outbreak; the Company's ability to file regulatory filings on a timely basis; timing of regulatory decisions and the impacts those decisions may have on the Company or its ability to implement them; and customer and stakeholder needs and expectations.

The Company also faces risks and costs associated with implementation of business continuity plans and modified work conditions, including the risks and costs associated with maintaining or reducing its workforce, making the required resources available to its workforce to enable them to continue essential work, including remotely where possible, and to keep its workforce healthy, as well as risks and costs associated with recovery of normal operations. Furthermore, the Company is dependent on third-party providers for certain activities, and relies on a strong international supply chain, which may also be adversely impacted, and which, in turn, could materially adversely impact the Company. See also "Other Developments – COVID-19".

Environment Risk
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. Although Hydro One is not a large emitter of greenhouse gases, the Company monitors its emissions to track and report on all sources, including sulphur hexafluoride or "SF6". The Company could be subject to costs and other risks related to emissions. 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 provided for in the Company's financial statements. 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 which may have a material adverse effect on the Company.

The Company's facilities are exposed to the effects of severe weather conditions and natural disasters. The Company recognizes the risks associated with potential climate change and has developed plans to respond as appropriate. Climate change may have the effect of shifting weather patterns and increasing the severity and frequency of extreme weather events and natural disasters, which could impact Hydro One's business. The Company's facilities may not withstand occurrences of these types in all circumstances. Notwithstanding Hydro One's efforts to adapt and increase grid resilience, the Company's facilities are exposed to risks which may have an adverse effect on grid resilience. The Company could also be subject to claims for damages from events which may be proximately connected with the Company's assets (for example, forest fires), 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. 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 the Company's other assets and for damage claims, such insurance coverage may have deductibles, limits and/or exclusions that may still expose the Company to material losses. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas.

In the event that the Company is unable to recover such costs, this could have a material adverse effect on the Company.

Risk Associated with Information Technology (IT), Operational Technology (OT) Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, modernizing, maintaining and managing complex IT and OT 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, as well as growing volume and complexity of data, increases its vulnerability, and 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 OT, 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 security for its assets that are not subject to these mandatory standards. The Company must also comply with various cyber-security and privacy-related regulatory requirements under the OEB's Ontario Cyber Security Framework and 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 IT and OT 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. Because it operates 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

A substantial majority of the Company's employees are unionized and are primarily 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. Agreements were also reached with the Society and the PWU to facilitate the insourcing of CSO services effective March 1, 2018. The Company reached an agreement with the Society for a collective agreement, covering the period from April 1, 2019 to March 31, 2021. The Company also reached a non-CSO collective agreement with the PWU, covering the period from April 1, 2020 to March 31 2023, and a CSO collective agreement with the PWU covering the period from October 1, 2019 to September 30, 2022. The Company also reached a collective agreement with the CUSW, covering the period from May 1, 2017 to April 30, 2022. Additionally, EPSCA and a number of building trade unions have agreements, to which Hydro One is bound, covering the period from May 1, 2020 to April 30, 2025 (see "Hydro One Work Force – Collective Agreements" for details). Future negotiations with unions present the risk of a labour disruption or dispute, risk to the Company's ability to sustain the continued supply of electricity to customers, as well as potential risks to public safety. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. Any of these could have a material adverse effect on the Company. The Society collective agreement requires renewal in 2021 (see "Hydro One Work Force – Collective Agreements" for details). Failure to renew this agreement on terms acceptable to Hydro One could have a material adverse effect on its business and results of operations and expose Hydro One to the risks noted above.

Work Force Demographic Risk

By the end of 2020, approximately 14% 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 2021, approximately 15% could be eligible. These percentages are not evenly spread across the Company's workforce, but tend to be most significant in the most senior levels of the Company's staff and among management staff. During 2020, approximately 3% of the Company's workforce (approximately the same percentage in 2019) 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 are sought after as they possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract, retain and deploy 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 coming due, including $803 million in 2021, $604 million in 2022 and $731 million in 2023. 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 $2,300 million commercial paper program which would mature within one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2021 and 2022. 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 Company 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.

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, including potentially negative 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. The Company issues debt from time to time to refinance maturing debt and for general corporate purposes. The Company is therefore exposed to fluctuations in interest rates in relation to such issuances of debt. Fluctuations in interest rates may also impact the funded position of Hydro One's Defined Benefit Pension Plan, and associated pension liability (See also "– Pension Plan Risk"). The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

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. For the transmission and distribution businesses in 2021, after transmission 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 has interest rate exposure associated with the refinancing of short- and long-term debt maturing in 2021 and beyond. The Company periodically uses 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 electricity 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, Capital Projects and Innovation
The Company continually incurs sustainment and development capital expenditures and monitors the condition of its assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure.

While traditionally a mature and stable industry, the electricity industry is facing rapid and dramatic technological change and increasing innovation, the consequences of which could have a material adverse effect on the Company, including a reduction in revenue.

Execution of the Company's capital expenditure programs is partially dependent on external factors, such as OEB approvals, environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, other interrelated projects being on schedule, and supply chain availability for equipment suppliers and consulting services. Many of these external factors are beyond the Company's control. 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. 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. Any delays in these new transmitters' projects may impact the Company's own projects that it is undertaking to in-service these new transmission assets.

Health and Safety Risk
Hydro One's work environment can be inherently dangerous and there is a risk to health and safety of both the public and our employees, as well as possible resultant operational and/or financial impacts. The Company is subject to federal and provincial legislation and regulations relating to health and safety. Findings of a failure to comply with these requirements could result in penalties and reputational risk, which could negatively impact the Company. Failure to comply could subject the Company to fines or other penalties. 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 Regulatory Authority of Ontario on a triennial

basis. The most recently filed valuation was prepared as at December 31, 2018, and was filed in September 2019, covering a three-year period from 2019 to 2021. Hydro One's contributions to its pension plan satisfy, and are expected to continue to satisfy, minimum funding requirements. Contributions beyond 2021 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.

Hydro One currently reports and recovers its pension costs on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension costs 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 also "– Regulatory Risks and Risks Relating to Hydro One's Revenues – Risk of Recoverability of Total Compensation Costs" for risks relating to recovery of pension costs.

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. If the services are disrupted, it could have a material adverse effect on the Company. Additionally, 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, contract disputes, claims by former employees and claims and proceedings by Indigenous groups. 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.

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 or controlled lands or has occupancy rights that are subject to expiry, it may incur material costs to obtain or renew such occupancy rights, or if such occupancy 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 occupancy 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 negative publicity or the public's negative perceptions towards Hydro One that may result in a detrimental impact to Hydro One's business, operations or financial condition leading to a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises, failure to comply with mandatory reliability regulations established by the NERC and NPCC, failure to adequately respond to social issues raised by employees, partners and/or stakeholders and other external forces. Adverse reputational events or political actions could have a material adverse effect 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 and community relationships. Any of these could have a material adverse impact on Hydro One and its business, financial condition and results of operations.

Risks Associated with Acquisitions
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 or liabilities. Realization of the anticipated benefits would 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.

Risks Relating to the Common Shares of Hydro One Limited
Hydro One's Common Shares trade on the TSX. The trading price of the Common Shares has in the past been, and may in the future be, subject to significant fluctuations. These fluctuations may be caused by events or factors related or unrelated to Hydro One's operating performance and/or beyond its control, including: the risk factors described herein; general economic conditions within Ontario and Canada, including changes in interest rates; changes in electricity prices; changes in electricity demand; weather conditions; actual or anticipated

fluctuations in Hydro One's quarterly and annual results and the results of public companies similar to Hydro One; Hydro One's businesses, operations, results and prospects; Hydro One's reputation and its relationship with the Province; the timing and amount of dividends, if any, declared on the Common Shares; future issuances of Common Shares or other securities by Hydro One or Hydro One Inc.; Hydro One's relationship with its regulator; changes in government regulation, taxes, legal proceedings or other developments; shortfalls in Hydro One's operating results from levels forecasted by securities analysts; investor sentiment toward energy companies in general; maintenance of acceptable credit ratings or credit quality; the impact of COVID-19 on Hydro One and the Province; and the general state of the securities markets. These and other factors may impair the development or sustainability of a liquid market for the Common Shares and the ability of investors to sell Common Shares at an attractive price.

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 47.3% 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. 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 investors. Notwithstanding the Governance Agreement, and in light of actions historically taken by the Province, there can be no assurance that the Province will not take other actions in the future that could be detrimental to the interests of investors in Hydro One. See "Risks Relating to Government Action" above.

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 CEO and Chair

Although director nominees (other than the CEO) 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, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the CEO.

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, including in each case its own director nominees but excluding the CEO 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 stakeholders of Hydro One.

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. See "Risks Relating to Government Action" above.

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 amounts related to the deferred income taxes, pension benefit liability, post-retirement and post-employment benefits, post-retirement and post-employment non-service costs, share-based compensation costs, foregone revenue, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers. They pertain primarily to 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, at some future date, 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 appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of polychlorinated biphenyl (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, 2020 decreased to 2.60% (from 3.10% at December 31, 2019) for pension benefits and decreased to 2.60% (from 3.10% at December 31, 2019) 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 of 5.75% is based on expectations of long-term rates of return at the beginning of the year and reflects the current pension plan asset mix. A new investment policy was adopted by Hydro One effective May 14, 2018 and is being implemented over several years. Notably this includes the move to real estate and infrastructure and the removal of specific regional equity and fixed income mandates. Hydro One's current expectation is that the new policy asset mix will not be fully implemented until 2021-2022. The expected rate of return for the December 31, 2020 disclosures and the 2021 registered pension plan expense is based on the plan's ultimate target asset mix.

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 increased from 1.30% per annum as at December 31, 2019 to approximately 1.40% per annum as at December 31, 2020. Based on the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, in addition to current and anticipated trends, management believes that a long-term assumption of 1.75% per annum is reasonable for employee future benefits liability valuation purposes as at December 31, 2020 (2.00% per annum was used for the purpose of December 31, 2019 disclosures and 2020 benefit cost).

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 reflects negotiated salary increases over the contract period as well as slightly lower expected increases in the short-term.

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, 2020 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. The health and dental trends reflect this study as well as slightly lower expected increases in long-term inflation.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting

Disclosure controls and procedures are the processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its CEO and CFO, as appropriate, to make timely decisions regarding required disclosure in the MD&A and financial statements. At the direction of the Company's CEO and CFO, 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 as at December 31, 2020.

Internal control over financial reporting is designed by, or under the direction of the CEO and CFO 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 CEO and CFO, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the 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 as at December 31, 2020.

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.

There were no changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2020 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 (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Hydro One
ASU 2017-04	January 2017	The amendment removes the second step of the previous two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	No impact upon adoption
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Hydro One
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-01	January 2020	The amendments clarify the interaction of the accounting for equity securities under Topic 321, investments under the equity method of accounting in Topic 323 and the accounting for certain forward contracts and purchased options accounted for under Topic 815.	January 1, 2021	No impact upon adoption
ASU 2020-06	August 2020	The update addresses the complexity associated with applying GAAP for certain financial instruments with characteristics of liabilities and equity. The amendments reduce the number of accounting models for convertible debt instruments and convertible preferred stock.	January 1, 2022	Under assessment
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

Summary of Fourth Quarter Results of Operations

Three months ended December 31 (millions of dollars, except EPS)	2020	2019	Change
Revenues			
Distribution	**1,457**	1,298	12.2%
Transmission	**398**	407	(2.2%)
Other	**12**	10	20.0%
	1,867	1,715	8.9%
Costs			
Purchased power	**1,046**	914	14.4%
OM&A			
Distribution	**185**	162	14.2%
Transmission	**73**	59	23.7%
Other	**15**	18	(16.7%)
	273	239	14.2%
Depreciation, amortization and asset removal costs	**239**	226	5.8%
	1,558	1,379	13.0%
Income before financing charges and income tax expense	**309**	**336**	**(8.0%)**
Financing charges	**119**	116	2.6%
Income before income tax expense	**190**	**220**	**(13.6%)**
Income tax expense	**27**	2	1,250.0%
Net income	**163**	**218**	**(25.2%)**
Net income to common shareholders of Hydro One	**161**	**211**	**(23.7%)**
Adjusted net income to common shareholders of Hydro One[1]	**161**	**211**	**(23.7%)**
Basic EPS	**$ 0.27**	$ 0.35	(22.9%)
Diluted EPS	**$ 0.27**	$ 0.35	(22.9%)
Basic Adjusted EPS[1]	**$ 0.27**	$ 0.35	(22.9%)
Diluted Adjusted EPS[1]	**$ 0.27**	$ 0.35	(22.9%)
Assets Placed In-Service			
Distribution	**308**	271	13.7%
Transmission	**565**	573	(1.4%)
Other	**5**	5	0.0%
	878	**849**	**3.4%**
Capital Investments			
Distribution	**210**	249	(15.7%)
Transmission	**361**	311	16.1%
Other	**6**	2	200.0%
	577	**562**	**2.7%**

1 See section "Non-GAAP Measures" for description and reconciliation of adjusted net income, and basic and diluted Adjusted EPS.

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2020 of $161 million is a decrease of $50 million or 23.7% from the prior year. Significant influences on net income included:

- higher revenues, net of purchased power, primarily resulting from:
  - an increase in distribution revenues, net of purchased power, mainly due to the OEB's decision on 2020 rates, as well as revenues related to the Peterborough Distribution and Orillia Power acquisitions which closed during the third quarter of 2020; partially offset by
  - a decrease in transmission revenues primarily due to lower peak demand, partially offset by the OEB's decision on 2020 rates.
- higher OM&A costs primarily resulting from:
  - COVID-19 related expenses, as discussed below,
  - lower insurance proceeds received in 2020; and
  - additional OPEB costs that are recognized in OM&A following the 2020-2022 OEB transmission decision and recovered in rates, therefore net income neutral;
- higher depreciation, amortization and asset removal costs in 2020 mainly due to the growth in capital assets and timing of asset removal costs.
- higher income tax expense primarily attributable to the following:
  - lower net tax deductions primarily related to tax depreciation in excess of depreciation, as well as additional tax on recovery

of certain OPEB costs through OM&A that were previously capitalized; and

— lower incremental tax deductions from deferred tax asset sharing mainly due to the 2018 foregone distribution revenue recognized in March 2019 following the receipt of the OEB decision on rates; partially offset by

— lower income before taxes.

Included in the Company's results for the quarter ended December 31, 2020 are costs incurred as a result of the COVID-19 pandemic. Total COVID-19 related costs in the quarter of $18 million consist primarily of the recognition of the bad debt provision following the issuance of the OEB staff proposal in December 2020, and direct expenses.

For additional disclosure related to the impact of COVID-19 on the Company's operations please see section "Other Developments – COVID-19".

EPS and Adjusted EPS

EPS and adjusted EPS was $0.27 in the fourth quarter of 2020, compared to EPS and adjusted EPS of $0.35 in the fourth quarter of 2019. The decrease in EPS and adjusted EPS was driven by lower earnings for the fourth quarter of 2020, as discussed above. See section "Non-GAAP Measures" for description and reconciliation of Adjusted EPS.

Revenues

The year-over-year decrease of $9 million or 2.2% in quarterly transmission revenues was primarily due to the following:

- lower peak demand driven by unfavourable weather in the fourth quarter of 2020, partially offset by
- the OEB's decision on 2020 rates, including the recovery of certain OPEB costs through OM&A that were previously capitalized and recovered in rates, therefore net income neutral, and a deferred regulatory adjustment related to asset removal costs in 2020.

The year-over-year increase of $27 million or 7.0% in quarterly distribution revenues, net of purchased power, was primarily due to the following:

- the OEB's decision on 2020 rates,
- higher revenues related to the Peterborough Distribution and Orillia Power acquisitions which closed during the third quarter of 2020, and
- a lower deferred regulatory adjustment related to the Earnings Sharing Mechanism in 2020.

See section "Non-GAAP Measures" for description and reconciliation of revenues, net of purchased power.

OM&A Costs

The year-over-year increase of $14 million or 23.7% in quarterly transmission OM&A costs was primarily due to the following:

- lower insurance proceeds received in 2020,
- additional OPEB costs that are recognized in OM&A following the 2020-2022 OEB transmission decision and recovered in rates, therefore net income neutral, and
- costs related to COVID-19.

The year-over-year increase of $23 million or 14.2% in quarterly distribution OM&A costs was primarily due to the following:

- costs related to COVID-19, consisting primarily of the recognition of the bad debt provision following the issuance of the OEB staff proposal in December 2020, and direct expenses, as well as
- higher corporate support costs.

Depreciation, Amortization and Asset Removal Costs

The increase of $13 million or 5.8% in depreciation, amortization and asset removal costs in the fourth quarter of 2020 was mainly due to the growth in capital assets and timing of asset removal costs.

Financing Charges

The $3 million or 2.6% year-over-year increase in financing charges for the quarter ended December 31, 2020 was primarily attributable to:

- higher interest expense on long-term debt as a result of increased debt levels largely driven by the debt issuances completed in the last quarter of 2020; partially offset by
- lower interest expense on short-term notes due to lower interest rate in the current year.

Income Taxes

Income tax expense for the fourth quarter of 2020 increased by $25 million compared to the same period in 2019. This resulted in a realized ETR of approximately 14.2% in the fourth quarter of 2020, compared to approximately 0.9% in the fourth quarter of the prior year.

The increase in income tax expense for the three months ended December 31, 2020 was primarily attributable to:

- lower net tax deductions primarily related to tax depreciation in excess of depreciation, as well as additional tax on recovery of certain OPEB costs through OM&A that were previously capitalized; and
- lower incremental tax deductions from deferred tax asset sharing mainly due to the 2018 foregone distribution revenue recognized in March 2019 following the receipt of the OEB decision on rates; partially offset by
- lower income before taxes.

Assets Placed In-Service

The decrease in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investment placed in-service for the new Leamington transmission station in 2019;
- lower volume of demand work due to equipment failures; and
- lower volume of assets placed in-service for IT projects; partially offset by
- timing of assets placed in-service for station sustainment investments; and
- higher volume of overhead lines and component replacements in 2020.

The increase in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- completion of Customer Contact Centre Technology Modernization project;

- completion of Woodstock Operation Centre; and
- higher volume of storm related asset replacements; partially offset by
- lower volume of distribution station refurbishments and equipment replacements; and
- timing of assets placed in-service for system capability reinforcement projects.

Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to the following:

- higher investments in multi-year development projects, including investments in the new Lakeshore switching station;
- higher volume of station refurbishments and replacements;
- investment in the new Ontario grid control centre in the City of Orillia; and
- higher volume of work required to adhere to the NERC Critical Infrastructure Protection standards; partially offset by
- lower volume of transportation and work equipment investments.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- lower investments in system capability reinforcement projects;
- lower spend on work for customer connections;
- lower volume of transportation and work equipment investments; partially offset by
- investment in the new Ontario grid control centre in the City of Orillia; and
- investment in the new Woodstock Operation Centre.

Hydro One Holdings Limited – Consolidating Summary Financial Information

Hydro One Limited fully and unconditionally guarantees the payment obligations of its wholly-owned subsidiary Hydro One Holdings Limited (HOHL) issuable under the short form base shelf prospectus dated December 17, 2020. Accordingly, the following consolidating summary financial information is provided in compliance with the requirements of section 13.4 of National Instrument 51-102 – *Continuous Disclosure Obligations* providing for an exemption for certain credit support issuers. The tables below contain consolidating summary financial information as at and for the years ended December 31, 2020 and December 31, 2019 for: (i) Hydro One Limited; (ii) HOHL; (iii) the subsidiaries of Hydro One Limited, other than HOHL, on a combined basis, (iv) consolidating adjustments, and (v) Hydro One Limited and all of its subsidiaries on a consolidated basis, in each case for the periods indicated. Such summary financial information is intended to provide investors with meaningful and comparable financial information about Hydro One Limited and its subsidiaries. This summary financial information should be read in conjunction with Hydro One Limited's most recently issued annual financial statements. This summary financial information has been prepared in accordance with US GAAP, as issued by the FASB.

Year ended December 31 (millions of dollars)	Hydro One Limited		HOHL		Subsidiaries of Hydro One Limited, other than HOHL		Consolidating Adjustments		Total Consolidated Amounts of Hydro One Limited	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue	**9**	17	**–**	–	**7,694**	6,775	**(413)**	(312)	**7,290**	6,480
Net Income (Loss) Attributable to Common Shareholders	**(7)**	(133)	**–**	(19)	**2,127**	1,188	**(350)**	(258)	**1,770**	778

Year ended December 31 (millions of dollars)	Hydro One Limited		HOHL		Subsidiaries of Hydro One Limited, other than HOHL		Consolidating Adjustments		Total Consolidated Amounts of Hydro One Limited	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Current Assets	**97**	84	**–**	–	**3,446**	2,440	**(1,554)**	(1,256)	**1,989**	1,268
Non-Current Assets	**3,426**	3,979	**–**	–	**44,408**	41,188	**(19,529)**	(19,374)	**28,305**	25,793
Current Liabilities	**454**	408	**–**	–	**4,066**	3,925	**(1,541)**	(1,246)	**2,979**	3,087
Non-Current Liabilities	**423**	–	**–**	–	**28,810**	25,201	**(12,546)**	(11,096)	**16,687**	14,105

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, the industry, regulatory and economic environments in which it operates, and includes 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, recovery and expected impacts and timing; expectations about the Company's liquidity and capital resources and operational requirements, including as a result of COVID-19; the Operating Credit Facilities; expectations regarding the Company's financing activities; the Company's maturing debt; the Company's derivative instruments; the Company's ongoing and planned projects, initiatives and expected capital investments, including expected results, costs and in-service and completion dates; the potential impact of delays on the Company's transmission in-service additions; the potential impact of COVID-19 on the Company's business and operations, including its impact on peak demand and electricity consumption, capital programs, supply chains, costs, allowance for doubtful accounts, foregone revenues, deferral accounts and the likelihood of recovery of certain costs in future rates; the Company's priorities in its response to COVID-19; contractual obligations and other commercial commitments; expected impacts relating to the deferred tax asset and the OEB's treatment thereof, including expected timing for the OEB's final decision in respect thereof and the Company's recognition of deferred tax regulatory assets, deferred tax liabilities and net income results; expectations relating to the recoverability of incremental costs and lost revenues from ratepayers in connection with the COVID-19 pandemic; expectations regarding the Company's ETR over the next five years; the impact of the Ontario Budget and the Ontario Electricity Rebate on customers; Bill 222 and its expected impacts; the number of Hydro One common shares issuable in connection with outstanding awards under the share grant plans and the LTIP; collective agreements and expectations regarding the ability to negotiate renewal collective agreements consistent with rate orders; the pension plan, future pension contributions, valuations and expected impacts; dividends; non-GAAP measures; risks relating to infectious disease outbreak, such as COVID-19; internal controls over financial reporting and disclosure; the MTN Program; the Universal Base Shelf Prospectus; the US Debt Shelf Prospectus; and the Company's acquisitions and mergers. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "would", "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: the scope of the COVID-19 pandemic and duration thereof as well as the effect and severity of corporate and other mitigation measures on the Company's operations, supply chain or employees; no unforeseen changes in the legislative and operating framework for Ontario's electricity market or for Hydro One specifically; 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; no significant changes to the Company's current credit ratings; no unforeseen impacts of new accounting pronouncements; no changes to expectations regarding electricity consumption; no unforeseen changes to economic and market conditions; recoverability of costs and expenses related to the COVID-19 pandemic, including the costs of customer defaults resulting from the pandemic; completion of operating and capital projects that have been deferred; 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:

- a significant expansion in length or severity of the COVID-19 pandemic restricting or prohibiting the Company's operations or significantly impacting the Company's supply chain or workforce;
- severity of mitigation measures related to the COVID-19 pandemic;
- delays in completion of and increases in costs of operating and capital projects;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders and the rate-setting models for transmission and distribution, actual performance against forecasts and capital expenditures, competition with other transmitters and other applications to the OEB, the regulatory treatment of the deferred tax asset, the recoverability of total compensation costs or denials of applications;
- 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, risks associated with the Province's exercise of further legislative and regulatory powers in the implementation of the *Hydro One Accountability Act*, risks relating to the ability of the Company to attract and retain qualified executive talent or the risk of a credit rating downgrade for the Company and its impact on the Company's funding and liquidity;
- risks relating to the location of the Company's assets on Reserve lands and the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves;
- 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, man-made events or

other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- the risk of non-compliance with environmental regulations and inability to recover environmental expenditures in rate applications and the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- risks associated with information system security and maintaining complex information technology (IT) and operational technology (OT) system infrastructure, including system failures or risks of cyber-attacks or unauthorized access to corporate IT and OT systems;
- the risk of labour disputes and inability to negotiate or renew appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risks related to the Company's workforce demographic and its potential inability to attract and retain qualified personnel;
- the 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 and financial instrument risk;
- risks associated with economic uncertainty and financial market volatility;
- 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 or the risk of increased competition for the development of large transmission projects or legislative changes affecting the selection of transmitters;
- risks associated with asset condition, capital projects and innovation, including public opposition to or delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk of failure to mitigate significant health and safety risks;
- 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 impact of the ownership by the Province of lands underlying the Company's transmission system;
- the risk associated with legal proceedings that could be costly, time-consuming or divert the attention of management and key personnel from the Company's business operations;
- the impact if the Company does not have valid occupational rights on third-party owned or controlled lands and the risks associated with occupational rights of the Company that may be subject to expiry;
- risks relating to adverse reputational events or political actions;
- risks relating to acquisitions, including the failure to realize anticipated benefits of such transaction at all, or within the time periods anticipated, and unexpected costs incurred in relation thereto;
- the inability to prepare financial statements using US GAAP; and
- the risk related to the impact of any new accounting pronouncements.

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 entitled "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, the US Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, 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.

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 disclosure controls and procedures and 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, 2020. 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 all material respects 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 fulfils 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:

Mark Poweska
President and Chief Executive Officer

Christopher Lopez
Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Hydro One Limited

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Hydro One Limited (the Company) as of December 31, 2020 and 2019, the related consolidated statements of operations and comprehensive income, changes in equity, and cash flows for each of the years in the two-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of regulatory assets and liabilities and the impact of rate regulation on the consolidated financial statements

As discussed in Note 2 to the consolidated financial statements, the Company accounts for its regulated operations in accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 980, Regulated Operations (ASC 980). Under ASC 980, the actions of the Company's regulator may result in the recognition of revenue and costs in time periods that are different than non-rate-regulated enterprises. When this occurs, the Company records incurred and accrued costs that it has assessed are probable of recovery in future electricity rates as regulatory assets. Obligations imposed or probable to be imposed by the regulator to refund previously collected revenue or to spend revenue collected from customers on future costs are recorded as regulatory liabilities. Under ASC 980, the carrying amounts of property, plant and equipment are impacted by the regulator's actions to the extent that incurred costs are allowed or disallowed to be recovered for rate-making purposes. As disclosed in Note 13 to the consolidated financial statements, as of December 31, 2020, the Company's regulatory assets were $4,676 million and regulatory liabilities were $297 million.

We identified the evaluation of regulatory assets and liabilities and the impact of rate regulation as a critical audit matter. Accounting for regulated operations under ASC 980 affects multiple financial statement accounts and disclosures in the Company's consolidated financial statements. Assessing the accounting for regulated operations requires industry knowledge and significant auditor judgment due to interpretations of regulatory decisions and judgments involved in evaluating the Company's assessment of the probability associated with recovery of regulatory assets and property, plant and equipment, and imposition of regulatory liabilities.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's regulatory accounting process. This included controls over the evaluation of the probability of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities, and controls over the monitoring and evaluation of regulatory developments that may affect the probability of recovering costs in future rates or imposing of regulatory liabilities. We evaluated the Company's assessment of the probability of recovery of the carrying amount of regulatory assets and property, plant and equipment and the disposition of regulatory liabilities, through consideration of selected on-going regulatory proceedings and decisions. For a selection of regulatory proceedings and decisions, we read the Company's assessment and interpretations and any written advice of management's external specialists with respect to the selected assessments and interpretations. For a selection of regulatory assets and liabilities, we recalculated the amounts recorded based on methodologies approved by the regulator and agreed the data used in the calculations to the Company's underlying books and records. We compared the amounts calculated by the Company to the amounts recorded in the consolidated financial statements.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

We have served as the Company's auditor since 2008.

Toronto, Canada
February 23, 2021

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2020	2019
Revenues		
Distribution (includes $283 related party revenues; 2019 – $282) (Note 29)	**5,507**	4,788
Transmission (includes $1,718 related party revenues; 2019 – $1,637) (Note 29)	**1,740**	1,652
Other	**43**	40
	7,290	6,480
Costs		
Purchased power (includes $2,513 related party costs; 2019 – $1,818) (Note 29)	**3,854**	3,111
Operation, maintenance and administration (Notes 4, 29)	**1,070**	1,181
Depreciation, amortization and asset removal costs (Note 5)	**884**	878
	5,808	5,170
Income before financing charges and income tax expense	**1,482**	1,310
Financing charges (Notes 4, 6)	**471**	514
Income before income tax expense	**1,011**	796
Income tax recovery (Note 7)	**(785)**	(6)
Net income	**1,796**	802
Other comprehensive loss (Note 8)	**(24)**	(2)
Comprehensive income	**1,772**	800
Net income attributable to:		
Noncontrolling interest (Note 28)	**8**	6
Preferred shareholders (Note 24)	**18**	18
Common shareholders	**1,770**	778
	1,796	802
Comprehensive income attributable to:		
Noncontrolling interest (Note 28)	**8**	6
Preferred shareholders (Note 24)	**18**	18
Common shareholders	**1,746**	776
	1,772	800
Earnings per common share (Note 26)		
Basic	**$2.96**	$1.30
Diluted	**$2.95**	$1.30
Dividends per common share declared (Note 25)	**$1.00**	$0.96

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	**2020**	2019
Assets		
Current assets:		
Cash and cash equivalents	**757**	30
Accounts receivable (Note 9)	**722**	701
Due from related parties (Note 29)	**326**	415
Other current assets (Note 10)	**184**	122
	1,989	1,268
Property, plant and equipment (Note 11)	**22,631**	21,501
Other long-term assets:		
Regulatory assets (Note 13)	**4,571**	2,676
Deferred income tax assets (Note 7)	**124**	748
Intangible assets (Note 12)	**514**	456
Goodwill (Note 4)	**373**	325
Other assets (Note 14)	**92**	87
	5,674	4,292
Total assets	**30,294**	27,061
Liabilities		
Current liabilities:		
Short-term notes payable (Note 17)	**800**	1,143
Long-term debt payable within one year (includes $303 measured at fair value; 2019 – $nil) (Notes 17, 18)	**806**	653
Accounts payable and other current liabilities (Note 15)	**1,044**	989
Due to related parties (Note 29)	**329**	302
	2,979	3,087
Long-term liabilities:		
Long-term debt (includes $nil measured at fair value; 2019 – $351) (Notes 17, 18)	**12,726**	10,822
Regulatory liabilities (Note 13)	**231**	167
Deferred income tax liabilities (Note 7)	**56**	61
Other long-term liabilities (Note 16)	**3,674**	3,055
	16,687	14,105
Total liabilities	**19,666**	17,192
Contingencies and Commitments (Notes 31, 32)		
Subsequent Events (Note 34)		
Noncontrolling interest subject to redemption (Note 28)	**22**	20
Equity		
Common shares (Note 24)	**5,678**	5,661
Preferred shares (Note 24)	**—**	418
Additional paid-in capital (Note 27)	**47**	49
Retained earnings	**4,838**	3,667
Accumulated other comprehensive loss	**(29)**	(5)
Hydro One shareholders' equity	**10,534**	9,790
Noncontrolling interest (Note 28)	**72**	59
Total equity	**10,606**	9,849
	30,294	27,061

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Timothy Hodgson
Chair

Russel Robertson
Chair, Audit Committee

Consolidated Statements of Changes in Equity

Year ended December 31, 2020 (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 28)	Total Equity
January 1, 2020	**5,661**	**418**	**49**	**3,667**	**(5)**	**9,790**	**59**	**9,849**
Net income	**—**	**—**	**—**	**1,788**	**—**	**1,788**	**6**	**1,794**
Other comprehensive loss (Note 8)	**—**	**—**	**—**	**—**	**(24)**	**(24)**	**—**	**(24)**
Distributions to noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**(2)**	**(2)**
Contributions from sale of noncontrolling interest (Note 4)	**—**	**—**	**—**	**—**	**—**	**—**	**9**	**9**
Dividends on preferred shares	**—**	**—**	**—**	**(18)**	**—**	**(18)**	**—**	**(18)**
Dividends on common shares	**—**	**—**	**—**	**(599)**	**—**	**(599)**	**—**	**(599)**
Common shares issued	**17**	**—**	**(10)**	**—**	**—**	**7**	**—**	**7**
Stock-based compensation (Note 27)	**—**	**—**	**8**	**—**	**—**	**8**	**—**	**8**
Preferred shares redeemed (Note 24)	**—**	**(418)**	**—**	**—**	**—**	**(418)**	**—**	**(418)**
December 31, 2020	**5,678**	**—**	**47**	**4,838**	**(29)**	**10,534**	**72**	**10,606**

Year ended December 31, 2019 (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 28)	Total Equity
January 1, 2019	5,643	418	56	3,459	(3)	9,573	49	9,622
Net income	—	—	—	796	—	796	4	800
Other comprehensive loss (Note 8)	—	—	—	—	(2)	(2)	—	(2)
Distributions to noncontrolling interest	—	—	—	—	—	—	(6)	(6)
Contributions from sale of noncontrolling interest (Note 4)	—	—	—	—	—	—	12	12
Dividends on preferred shares	—	—	—	(18)	—	(18)	—	(18)
Dividends on common shares	—	—	—	(570)	—	(570)	—	(570)
Common shares issued	18	—	(12)	—	—	6	—	6
Stock-based compensation (Note 27)	—	—	5	—	—	5	—	5
December 31, 2019	5,661	418	49	3,667	(5)	9,790	59	9,849

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Year ended December 31 (millions of Canadian dollars)	**2020**	2019
Operating activities		
Net income	**1,796**	802
Environmental expenditures	**(23)**	(25)
Adjustments for non-cash items:		
Depreciation and amortization (Note 5)	**783**	777
Regulatory assets and liabilities	**68**	(48)
Deferred income tax recovery	**(823)**	(30)
Unrealized loss on Foreign-Exchange Contract (Note 4)	**—**	22
Derecognition of deferred financing costs (Note 4)	**—**	24
Other	**49**	37
Changes in non-cash balances related to operations (Note 30)	**180**	55
Net cash from operating activities	**2,030**	1,614
Financing activities		
Long-term debt issued	**2,725**	1,500
Long-term debt repaid	**(653)**	(730)
Short-term notes issued	**4,070**	4,217
Short-term notes repaid	**(4,413)**	(4,326)
Short-term debt repaid (Note 4)	**(20)**	—
Convertible debentures redeemed (Note 4)	**—**	(513)
Dividends paid	**(617)**	(588)
Distributions paid to noncontrolling interest	**(2)**	(9)
Contributions received from sale of noncontrolling interest (Note 4)	**9**	12
Common shares issued (Note 24)	**7**	6
Costs to obtain financing	**(14)**	(8)
Preferred shares redeemed (Note 24)	**(418)**	—
Net cash from (used in) financing activities	**674**	(439)
Investing activities		
Capital expenditures (Note 30)		
Property, plant and equipment	**(1,718)**	(1,513)
Intangible assets	**(126)**	(115)
Capital contributions received (Note 30)	**—**	3
Acquisitions (Note 4)	**(126)**	—
Other	**(7)**	(3)
Net cash used in investing activities	**(1,977)**	(1,628)
Net change in cash and cash equivalents	**727**	(453)
Cash and cash equivalents, beginning of year	**30**	483
Cash and cash equivalents, end of year	**757**	30

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
For the years ended December 31, 2020 and 2019

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). At December 31, 2020, the Province held approximately 47.3% (2019 – 47.3%) of the common shares of Hydro One. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Rate Setting

The Company's 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), as well as an approximately 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation (SON), and an approximately 55% interest in Niagara Reinforcement Limited Partnership (NRLP), a limited partnership between Hydro One and Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation (collectively, the First Nations Partners). See Note 4 – Business Combinations for additional information.

Hydro One's distribution business consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks, Hydro One Remote Communities Inc. (Hydro One Remote Communities), and Orillia Power Distribution Corporation (Orillia Power), as well as the distribution business and assets acquired from Peterborough Distribution Inc. (Peterborough Distribution). See Note 4 – Business Combinations for additional information.

Transmission

On March 7, 2019, the Ontario Energy Board (OEB) issued its reconsideration decision (DTA Decision) with respect to Hydro One's rate-setting treatment of the benefits of the deferred tax asset resulting from the transition from the payments in lieu of tax regime to tax payments under the federal and provincial tax regimes. On July 16, 2020, the Ontario Divisional Court rendered its decision on the Company's appeal of the OEB's DTA Decision. See Note 13 – Regulatory Assets and Liabilities.

On April 23, 2020, the OEB rendered its decision on Hydro One Networks' 2020-2022 transmission rate application (2020-2022 Transmission Decision). On July 16, 2020, the OEB issued its final rate order for the 2020-2022 transmission rates approving a revenue requirement of $1,630 million, $1,701 million and $1,772 million for 2020, 2021 and 2022, respectively. On July 30, 2020, the OEB issued its decision for Uniform Transmission Rates (UTRs). The 2020 UTRs that were put in place on an interim basis on January 1, 2020 continued for the remainder of 2020 in light of the COVID-19 pandemic. On December 17, 2020, the OEB issued its decision and order setting the final 2021 UTRs effective January 1, 2021, which included the approval of a two-year disposition period for Hydro One Network's 2020 foregone revenue including interest, beginning on January 1, 2021.

On July 31, 2019, B2M LP filed a transmission rate application for 2020-2024. On January 16, 2020, the OEB approved the 2020 base revenue requirement of $33 million, and a revenue cap escalator index for 2021 to 2024.

On October 25, 2019, NRLP filed its revenue cap incentive rate application for 2020-2024. On December 19, 2019, the OEB approved NRLP's proposed 2020 revenue requirement of $9 million on an interim basis effective January 1, 2020. On April 9, 2020, final OEB approval was received.

HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB Mergers Acquisitions Amalgamations and Divestitures (MAAD) decision dated October 13, 2016.

Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. On March 7, 2019, the OEB rendered its decision on the distribution rates application. In accordance with the OEB decision, the Company filed its draft rate order reflecting updated revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022. On June 11, 2019, the OEB approved the rate order confirming these updated revenue requirements.

On April 16, 2020, the OEB approved a 2% increase to Hydro One Remote Communities' 2019 base rates for new rates effective May 1, 2020, with a deferred implementation date of November 1, 2020 due to COVID-19. On October 8, 2020, the OEB authorized Hydro One Remote Communities to implement a rate rider for the recovery of foregone revenues resulting from postponing rate implementation, effective until April 30, 2021.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation and Presentation

These Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Inter-company 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, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.

Since late March 2020, the impact of the COVID-19 pandemic (COVID-19 or the pandemic) has been reflected in the Consolidated Financial Statements. While the pandemic has resulted in incremental operating costs and lost revenues, the Company has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no material impact. Additional details regarding the impact of the pandemic on the Consolidated Financial Statements are available in Note 9 – Accounts Receivable and Note 13 – Regulatory Assets and Liabilities.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financial results and operations.

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 prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

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

Nature of Revenues

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved UTRs which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are 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.

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, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. 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) or other comprehensive loss (OCL) 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

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year's taxable income. 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 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 tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward 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 associated with its regulated operations which are considered to be more likely than not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

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.

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, and information technology (IT). 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, 2020 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	14 years	1% – 15%	5%
Administration and service	21 years	1% – 20%	4%
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 quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the 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 the assessment performed as at September 30, 2020 and with no significant events since, the Company has concluded that goodwill was not impaired at December 31, 2020.

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 Inc. 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, 2020 and 2019, 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/Loss

Comprehensive income/loss is comprised of net income/loss and OCI/OCL. Hydro One presents net income/loss and OCI/OCL in a single continuous consolidated statement of operations and comprehensive income/loss.

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 its net realizable 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. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

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 18 – 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, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI). Amounts in AOCI are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the consolidated statements of operations as the hedged item. 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, 2020 or 2019.

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 plan (Pension Plan) and its 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 (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO 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 PBO of the plan, an asset is recognized equal to the net overfunded PBO. 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 (DC 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 (OM&A) 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, corporate and government debt securities as well as unlisted real estate and unlisted infrastructure investments, are recorded at fair value at the end of each year. Hydro One records a regulatory asset equal to the net underfunded PBO for its pension plan. Defined benefit pension costs are attributed to labour costs on a cash basis and a portion directly related to acquisition and development of capital assets is capitalized as part of the cost of property, plant and equipment and intangible assets. The remaining defined benefit pension costs are charged to results of operations (OM&A costs).

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 benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

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 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 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 awards 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 (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third-party. 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. This uncertainty is incorporated in the fair value measurement of the obligation.

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. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. 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.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the consolidated balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Hydro One
ASU 2017-04	January 2017	The amendment removes the second step of the previous two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	No impact upon adoption
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2019-01	March 2019	This amendment carries forward the exemption previously provided under ASC 840 relating to the determination of the fair value of underlying assets by lessors that are not manufacturers or dealers. It also provides for clarification on cash-flow presentation of sales-type and financing leases and clarifies that transition disclosures under Topic 250 are applicable in the adoption of ASC 842.	January 1, 2020	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Hydro One
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-01	January 2020	The amendments clarify the interaction of the accounting for equity securities under Topic 321, investments under the equity method of accounting in Topic 323 and the accounting for certain forward contracts and purchased options accounted for under Topic 815.	January 1, 2021	No impact upon adoption
ASU 2020-06	August 2020	The update addresses the complexity associated with applying GAAP for certain financial instruments with characteristics of liabilities and equity. The amendments reduce the number of accounting models for convertible debt instruments and convertible preferred stock.	January 1, 2022	Under assessment
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

4. BUSINESS COMBINATIONS

Acquisition of Peterborough Distribution Assets

On August 1, 2020, Hydro One completed the acquisition of the business and distribution assets of Peterborough Distribution, an electricity distribution company located in east central Ontario, from the City of Peterborough, for a purchase price of $104 million, including the assumption of agreed upon liabilities and closing adjustments. The purchase price is comprised of a cash payment of $105 million, including a deposit of $4 million paid in 2018 and $101 million paid on closing of the transaction, partially offset by a purchase price adjustment of $1 million. As the acquired business and distribution assets of Peterborough Distribution meet the definition of a business, the acquisition has been accounted for as a business acquisition.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Working capital	7
Property, plant and equipment	64
Regulatory assets	1
Goodwill	33
Other long-term liabilities	(1)
	104

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and assumptions and reflects the fair value of consideration paid.

The goodwill estimate of $33 million arising from the Peterborough Distribution acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Peterborough Distribution. All of the goodwill was assigned to Hydro One's Distribution Business segment. Peterborough Distribution contributed revenues of $51 million and net income of $nil to the Company's consolidated financial results for the year ended December 31, 2020. All costs related to the acquisition have been expensed through the statement of operations and comprehensive income. The disclosure of Peterborough Distribution's pro forma information is immaterial to the Company's consolidated financial results for the year ended December 31, 2020.

Acquisition of Orillia Power

On September 1, 2020, Hydro One completed the acquisition of Orillia Power, an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for a purchase price of $28 million, including closing adjustments. The purchase price is comprised of a cash payment of $26 million, including a deposit of $1 million paid in 2016, $25 million paid on closing of the transaction, as well as a purchase price adjustment of $2 million.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Working capital	2
Property, plant and equipment	32
Deferred income tax assets	1
Goodwill	15
Short-term debt	(20)
Regulatory liabilities	(1)
Other long-term liabilities	(1)
	28

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and assumptions and reflects the fair value of consideration paid. In September 2020, Hydro One repaid the $20 million of short-term debt assumed as part of the Orillia Power acquisition.

The goodwill estimate of $15 million arising from the Orillia Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Orillia Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. Orillia Power contributed revenues of $15 million and net income of $nil to the Company's consolidated financial results for the year ended December 31, 2020. All costs related to the acquisition have been expensed through the statement of operations and comprehensive income. The disclosure of Orillia Power's pro forma information is immaterial to the Company's consolidated financial results for the year ended December 31, 2020.

NRLP

In 2018, Hydro One entered into an agreement with the First Nations Partners, wherein a noncontrolling equity interest in Hydro One's limited partnership, NRLP, would be made available for purchase at fair value by the First Nations Partners. On September 19, 2018, NRLP was formed to own a new 230 kV transmission line (Niagara Line) in the Niagara region. The Niagara Line enables generators in the Niagara area to connect to the load centres of the Greater Toronto and Hamilton areas. Hydro One Networks maintains and operates the Niagara Line in accordance with an operation and management services agreement. On September 12, 2019, the OEB granted NRLP a transmission licence and granted Hydro One Networks leave to sell the applicable Niagara Line assets to NRLP.

On September 18, 2019, the applicable Niagara Line assets were transferred from Hydro One Networks to NRLP for $119 million and operation of the line was contracted to Hydro One Networks. This transfer was financed with 60% debt ($71 million) and 40% equity ($48 million). The cash payment of $71 million was financed by debt sourced by NRLP from a Hydro One subsidiary, and the $48 million equity comprised partnership units issued by NRLP to Hydro One Networks. Subsequently, on the same date, Hydro One Networks sold to the Six Nations of the Grand River Development Corporation and, through a trust, to the Mississaugas of the Credit First Nation a 25.0% and 0.1%, respectively, equity interest in NRLP pa nership units for total consideration of $12 million, representing the fair value of the equity interest acquired.

On January 31, 2020, the Mississaugas of the Credit First Nation purchased an additional 19.9% equity interest in NRLP pa nership units from Hydro One Networks for total cash consideration of $9 million. Following this transaction, Hydro One's interest in the equity po ion of NRLP pa nership units was reduced to 55%, with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation owning 25% and 20%, respectively, of the equity interest in NRLP pa nership units.

NRLP is fully consolidated in these Consolidated Financial Statements as it is controlled by Hydro One. The First Nations Pa ners' noncontrolling interest in NRLP is classi ed within equity. See Note 28 – Noncontrolling Interest for additional information.

Termination of the Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger). In January 2019, Hydro One and Avista Corporation announced that the companies mutually agreed to terminate the Merger agreement. The following amounts related to the termination of the Merger agreement were recorded by the Company during the rst qua er of the year ended December 31, 2019.

$138 million (US$103 million) for payment of the Merger termination fee recorded in OM&A costs;

$22 million n ancing charges, due to reversal of previously recorded unrealized gains upon termination of the deal-contingent foreign-exchange forward contract (Foreign-Exchange Contract);

redemption of $513 million con ve ible debentures and payment of related interest of $7 million; and

$24 million n ancing charges, due to derecognition of the deferred nancing costs related to conve ible debentures.

5. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December (millions of dollars)		
Depreciation of prope y, plant and equipment		
Amo ization of intangible assets		
Amo ization of regulatory assets		
Depreciation and amo ization		
Asset removal costs		

6. FINANCING CHARGES

Year ended December (millions of dollars)		
Interest on long-term debt		
Interest on sho -term notes		
Realized loss on cash ow hedges (interest-rate swap agreements) (Note ,)		—
Derecognition of deferred nancing costs (Note)	—	
Unrealized loss on Foreign-Exchange Contract (Notes ,)	—	
Interest on conve ible debentures (Note)	—	
Other		
Less: Interest capitalized on construction and development in progress	( )	( )
Interest earned on cash and cash equivalents	( )	( )

7. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely than not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's consolidated tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery 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)	**2020**	2019
Income before income tax expense	**1,011**	796
Income tax expense at statutory rate of 26.5% (2019 – 26.5%)	**268**	211
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization[1]	**(102)**	(105)
Impact of tax deductions from deferred tax asset sharing[2]	**(41)**	(60)
Overheads capitalized for accounting but deducted for tax purposes	**(21)**	(21)
Interest capitalized for accounting but deducted for tax purposes	**(13)**	(13)
Environmental expenditures	**(6)**	(7)
Pension and post-retirement benefit contributions in excess of pension expense	**(4)**	(11)
Other	**—**	(3)
Net temporary differences attributable to regulated business	**(187)**	(220)
Net permanent differences	**1**	3
Recognition of deferred income tax regulatory asset (Note 13)	**(867)**	—
Total income tax recovery	**(785)**	(6)
Effective income tax rate	**(77.6%)**	(0.8%)

1 Includes accelerated tax depreciation of up to three times the first-year rate for certain eligible capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028, as introduced in the 2019 federal and Ontario budgets and enacted in the second quarter of 2019.

2 Prior to the ODC Decision, the impact represents tax deductions from deferred asset tax sharing given to ratepayers as previously mandated by the OEB. Subsequent to the ODC Decision, the impact represents the recovery of deferred tax asset sharing currently allocated to rate-payers. See Note 13 – Regulatory Assets and Liabilities.

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	**2020**	2019
Current income tax expense	**29**	24
Deferred income tax recovery	**(814)**	(30)
Total income tax recovery	**(785)**	(6)

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carryforward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Company's regulated business are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and liabilities consisted of the following:

As at December 31 (millions of dollars)	2020	2019
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	**685**	638
Pension obligations	**607**	405
Non-capital losses	**323**	331
Non-depreciable capital property	**271**	271
Tax credit carryforwards	**119**	92
Investment in subsidiaries	**100**	95
Depreciation and amortization in excess of capital cost allowance	**57**	59
Environmental expenditures	**48**	51
Other	**14**	20
	2,224	1,962
Less: valuation allowance	**(380)**	(375)
Total deferred income tax assets	**1,844**	1,587
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	**1,022**	377
Regulatory assets and liabilities	**728**	495
Goodwill	**11**	10
Other	**15**	18
Total deferred income tax liabilities	**1,776**	900
Net deferred income tax assets	**68**	687

The net deferred income tax assets are presented on the consolidated balance sheets as follows:

As at December 31 (millions of dollars)	2020	2019
Long-term:		
Deferred income tax assets	**124**	748
Deferred income tax liabilities	**(56)**	(61)
Net deferred income tax assets	**68**	687

The valuation allowance for deferred tax assets as at December 31, 2020 was $380 million (2019 – $375 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2020 and 2019, 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)	2020	2019
2034	**–**	2
2035	**171**	221
2036	**552**	551
2037	**172**	172
2038	**95**	95
2039	**200**	202
2040	**27**	–
Total losses	**1,217**	1,243

8. OTHER COMPREHENSIVE LOSS

Year ended December 31 (millions of dollars)	**2020**	2019
Gain (loss) on cash flow hedges (interest-rate swap agreements) (Notes 6, 18)[1]	**(20)**	2
Loss on pension and other post-employment benefits (OPEB) transfer (Note 20)	**(6)**	—
Other	**2**	(4)
	(24)	(2)

1 Includes $7 million realized loss on cash flow hedges reclassified to financing charges (2019 – $nil).

9. ACCOUNTS RECEIVABLE

As at December 31 (millions of dollars)	**2020**	2019
Accounts receivable – billed	**347**	330
Accounts receivable – unbilled	**421**	393
Accounts receivable, gross	**768**	723
Allowance for doubtful accounts	**(46)**	(22)
Accounts receivable, net	**722**	701

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)	**2020**	2019
Allowance for doubtful accounts – beginning	**(22)**	(21)
Write-offs	**11**	18
Additions to allowance for doubtful accounts[1]	**(35)**	(19)
Allowance for doubtful accounts – ending	**(46)**	(22)

1 Additions to allowance for doubtful accounts for the year ended December 31, 2020 include incremental $14 million related to the COVID-19 pandemic which were recognized in OM&A in 2020 (2019 – $nil).

10. OTHER CURRENT ASSETS

As at December 31 (millions of dollars)	**2020**	2019
Regulatory assets (Note 13)	**105**	52
Prepaid expenses and other assets	**53**	49
Materials and supplies	**23**	21
Derivative assets (Note 18)	**3**	—
	184	122

11. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2020 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	**18,213**	**5,989**	**876**	**13,100**
Distribution	**11,544**	**3,949**	**101**	**7,696**
Communication	**1,395**	**1,079**	**45**	**361**
Administration and service	**1,729**	**959**	**113**	**883**
Easements	**671**	**80**	**—**	**591**
	33,552	**12,056**	**1,135**	**22,631**

As at December 31, 2019 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	17,454	5,714	711	12,451
Distribution	10,991	3,747	85	7,329
Communication	1,355	1,002	43	396
Administration and service	1,617	931	53	739
Easements	663	77	—	586
	32,080	11,471	892	21,501

Financing charges capitalized on property, plant and equipment under construction were $46 million in 2020 (2019 – $45 million).

12. INTANGIBLE ASSETS

As at December 31, 2020 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	**1,034**	**581**	**59**	**512**
Other	**7**	**5**	**—**	**2**
	1,041	**586**	**59**	**514**

As at December 31, 2019 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	912	512	56	456
Other	5	5	—	—
	917	517	56	456

Financing charges capitalized to intangible assets under development were $3 million in 2020 (2019 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2021 – $73 million; 2022 – $70 million; 2023 – $60 million; 2024 – $49 million; and 2025 – $48 million.

13. 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:

As at December 31 (millions of dollars)	2020	2019
Regulatory assets:		
Deferred income tax regulatory asset	**2,343**	1,109
Pension benefit regulatory asset	**1,660**	1,125
Deferred tax asset sharing	**204**	—
Environmental	**133**	141
Post-retirement and post-employment benefits – non-service cost	**113**	96
Foregone revenue deferral	**63**	67
Post-retirement and post-employment benefits	**59**	105
Stock-based compensation	**41**	42
Conservation and Demand Management (CDM) variance	**16**	—
Debt premium	**12**	17
Other	**32**	26
Total regulatory assets	**4,676**	2,728
Less: current portion	**(105)**	(52)
	4,571	2,676
Regulatory liabilities:		
Retail settlement variance account	**92**	23
Tax rule changes variance	**70**	44
Earnings sharing mechanism deferral	**37**	21
Pension cost differential	**31**	31
Green energy expenditure variance	**22**	31
Asset removal costs cumulative variance	**19**	—
External revenue variance	**7**	6
Deferred income tax regulatory liability	**4**	5
Distribution rate riders	**1**	42
Other	**14**	9
Total regulatory liabilities	**297**	212
Less: current portion	**(66)**	(45)
	231	167

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 2020 income tax expense would have been higher by approximately $187 million (2019 – higher by $221 million), of which $146 million is included in Deferred Income Tax Regulatory Asset and Liability with the remaining $41 million included in Deferred Tax Asset Sharing.

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original 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, 1998* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One 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 have resulted in an impairment of a portion of both Hydro One Networks' transmission and distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Ontario Divisional Court (Appeal). In both cases, the Company's position was that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Original Decision relating to the deferred tax asset to an OEB panel for reconsideration.

On March 7, 2019, the OEB issued its DTA Decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks'

2018–2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result, as at December 31, 2018, the Company recorded impairment charges relating to Hydro One Networks' distribution and transmission deferred income tax regulatory asset. Notwithstanding the recognition of the effects of the DTA Decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's DTA Decision. The appeal was heard on November 21, 2019.

On July 16, 2020, the Ontario Divisional Court rendered its decision (ODC Decision) on the Company's appeal of the OEB's DTA Decision.

In connection with the ODC Decision, the Company recorded a reversal of the previously recognized impairment charge of Hydro One Networks' distribution and transmission deferred income tax regulatory asset in its financial statements for the year ended December 31, 2020. The reversal of the previously recognized impaired charge included the regulatory asset relating to the cumulative deferred tax asset amounts shared with ratepayers (deferred tax asset sharing) up to and including June 30, 2020 by Hydro One Networks' distribution and transmission segments of $58 million and $118 million, respectively. Hydro One recognized deferred income tax regulatory assets of $504 million and $673 million for Hydro One Networks distribution and transmission segments, respectively, and associated deferred income tax liability of $310 million. The Company also recorded an increase in net income of $867 million as deferred income tax recovery during the year ended December 31, 2020.

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 the present value of the actuarially determined benefit obligation 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, OCL would have been higher by $470 million (2019 – $597 million) and OM&A expenses would have been higher by $89 million (2019 – lower by $20 million).

Deferred Tax Asset Sharing

On October 2, 2020, the OEB issued a procedural order to implement the direction of the Ontario Divisional Court and required Hydro One to submit its proposal for the recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2022 period. As at December 31, 2020, Hydro One recorded a regulatory asset of $204 million for the cumulative deferred tax asset amounts shared with ratepayers since 2017 to date, consisting of $70 million and $134 million for Hydro One Networks' distributions and transmission segments, respectively. As a result of the OEB's procedural order, the $204 million regulatory asset relating to the cumulative deferred tax asset amounts allocated to ratepayers since 2017 has been separately presented from the deferred income tax regulatory asset. Until the OEB issues the order to implement the recovery of the deferred tax asset amounts allocated to ratepayers for the 2017 to 2022 period, this $204 million regulatory asset will continue to increase to recognize the additional amounts shared with ratepayers during the reporting period.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2020, the environmental regulatory asset increased by $12 million (2019 – decreased by $3 million) to reflect related changes in the Company's LAR environmental liabilities. 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, 2020 OM&A expenses would have been higher by $12 million (2019 – lower by $3 million). In addition, 2020 amortization expense would have been lower by $23 million (2019 – $25 million), and 2020 financing charges would have been higher by $3 million (2019 – $4 million).

Post-Retirement and Post-Employment Benefits – Non-Service Cost

Hydro One has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. As part of Hydro One Networks' 2020-2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. Hydro One Networks distribution continues to record the non-service cost component of OPEBs in this account until its next rebasing application. The OEB approved the disposition of Hydro One Networks transmission's account balance as at December 31, 2018, including accrued interest, which is being collected from ratepayers over a three-year period ending December 31, 2022.

Foregone Revenue Deferral

As at December 31, 2020, the foregone revenue deferral account is primarily made up of the difference between revenue earned by Hydro One Networks transmission, NRLP, B2M LP, and HOSSM under the approved UTRs based on OEB-approved 2020 rates revenue requirement and load forecast and the revenues earned under interim 2020 UTRs. Hydro One Networks transmission's foregone revenue, including accrued interest, is being collected from ratepayers over a two-year period ending December 31, 2022. NRLP, B2M LP, and HOSSM's foregone revenue, including accrued interest, is being collected from ratepayers over a one-year period ended December 31, 2021. As at December 31, 2019, the foregone revenue deferral account was primarily made up of the difference between revenue earned based on distribution rates approved by the OEB in Hydro One Networks' 2018-2022 distribution rates application, effective May 1, 2018, and revenue earned under the interim rates until the approved 2018 and 2019 rates were implemented on July 1, 2019. This amount was recovered from ratepayers over an eighteen-month period ending December 31, 2020.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. 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 the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2020 OCL would have been lower by $46 million (2019 – higher by $235 million).

Stock-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, OM&A expenses would be lower by $1 million (2019 – $nil). 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.

CDM Variance

The CDM variance account tracks the impact of actual CDM and demand response programs on the actual load forecast compared to the estimated load forecast included in revenue requirement. As per the OEB's decision on Hydro One Networks' 2017 and 2018 transmission rates, and 2019 transmission rates, this account was maintained to record any variances for 2017, 2018, and 2019. A CDM variance amount for 2017 was calculated and proposed for disposition in Hydro One Networks' 2020-2022 transmission rate application. In April 2020, the amount as at December 31, 2018, including accrued interest, was approved for disposition by the OEB and was recognized as a regulatory asset. The amount was approved to be recovered from ratepayers over a three-year period ending December 31, 2022.

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.

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. The RSVA account tracks the difference between the cost of power purchased from the Independent Electricity System Operator (IESO) and the cost of power recovered from ratepayers. The balance as at December 31, 2014, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider. The balance as at December 31, 2019, including accrued interest, was approved for disposition over a one-year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting Hydro One to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including Hydro One to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized.

Earnings Sharing Mechanism Deferral

In March 2019, the OEB approved the establishment of an earnings sharing mechanism deferral account for Hydro One Networks distribution to record over-earnings including tax impacts, if any, realized for any year from 2018 to 2022. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with distribution ratepayers. This account is asymmetrical to the benefit of ratepayers. The balance as at December 31, 2019, including accrued interest, was approved for disposition on an interim basis over a one year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application. A similar account was also approved for B2M LP in January 2020, and Hydro One Networks transmission and NRLP in April 2020. No amounts have been recorded for these subsidiaries.

Pension Cost Differential

Variances between the pension cost recognized and the cost embedded in rates as part of the rate-setting process for Hydro One Networks' transmission and distribution businesses are recognized as a regulatory asset or regulatory liability, as the case may be. Variances into the account were not recognized for the distribution business in 2019 in accordance with the OEB's decision on the motion to review and vary the OEB's decision as it relates to rates revenue requirement recovery of employer pension costs. In March 2019, the OEB approved the disposition of the distribution business portion of the balance as at December 31, 2016, including accrued interest, and the balance was transferred to the 2019-2020 Rate Rider. In April 2020, the OEB approved the disposition of the transmission business portion of the balance as at December 31, 2018, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2022. In the absence of rate-regulated accounting, 2020 revenue would have been higher by $1 million (2019 – $5 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. The smart grid variance account balance as at December 31, 2016, including accrued interest, was approved for disposition by the OEB in March 2019, and was transferred to the 2019-2020 Rate Rider.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for Hydro One Networks transmission to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs incurred from 2020 to 2022. This account is asymmetrical to the benefit of ratepayers on a cumulative basis over the 2020-2022 rate period.

External Revenue Variance

The external revenue variance account balance reflects the difference between Hydro One Networks transmission's actual export service revenue and external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts. In April 2020, the OEB approved the disposition of the external revenue variance account as at December 31, 2018, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2022.

Distribution Rate Riders

In March 2019, as part of its decision on Hydro One Networks' distribution rates application for 2018-2022, the OEB approved the disposition of certain deferral and variance accounts which were accumulated in a 2019-2020 Rate Rider. The Distribution Rate Riders balance includes the 2019-2020 Rate Rider, where amounts were returned to ratepayers over an 18-months period ending December 31, 2020. There is a balance in the 2019-2020 Rate Rider that remains which represents amounts that shall be collected from ratepayers in a future rate application. This amount is largely offset by the 2015-2017 Rate Rider balance, which was approved for disposition over a one-year period ending December 31, 2021 by the OEB as part of Hydro One Networks distribution 2021 annual update rate application.

COVID-19 Emergency Deferral

The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from Postponing Rate Implementation, and (v) Bad Debt.

During the year, the Company had initially assessed that it was probable that incremental bad debt expense associated with the COVID-19 pandemic would be recovered in future rates, and as a result, a $14 million regulatory asset had been recognized. On December 16, 2020, the OEB Staff released their proposal on the COVID-19 deferral accounts which introduces certain criteria that may need to be satisfied for amounts to be eligible for recovery. Based on Hydro One's interpretation of the OEB Staff's proposal, the Company reversed the regulatory asset recorded for incremental bad debt and recognized a corresponding increase to bad debt expense in the consolidated statement of operations and comprehensive income. Hydro One continues to track certain incremental costs and lost revenues that have arisen due to the COVID-19 pandemic. As at December 31, 2020, Hydro One has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory assets.

14. OTHER LONG-TERM ASSETS

As at December 31 (millions of dollars)	**2020**	2019
Right-of-Use assets (Note 23)	**77**	75
Investments (Note 18)	**7**	2
Derivative assets (Note 18)	**—**	3
Other long-term assets	**8**	7
	92	87

15. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 (millions of dollars)	**2020**	2019
Accrued liabilities	**566**	612
Accounts payable	**238**	189
Accrued interest	**118**	104
Regulatory liabilities (Note 13)	**66**	45
Environmental liabilities (Note 21)	**33**	30
Lease obligations (Note 23)	**12**	9
Derivative liabilities (Note 18)	**11**	—
	1,044	989

16. OTHER LONG-TERM LIABILITIES

As at December 31 (millions of dollars)	**2020**	2019
Post-retirement and post-employment benefit liability (Note 20)	**1,797**	1,723
Pension benefit liability (Note 20)	**1,660**	1,125
Environmental liabilities (Note 21)	**100**	111
Lease obligations (Note 23)	**70**	69
Derivative liabilities (Note 18)	**14**	—
Asset retirement obligations (Note 22)	**13**	10
Long-term accounts payable	**3**	3
Other long-term liabilities	**17**	14
	3,674	3,055

17. 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 $2,300 million. 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 revolving standby credit facilities totalling $2,300 million.

At December 31, 2020, Hydro One's consolidated committed, unsecured and undrawn credit facilities (Operating Credit Facilities) consisted of the following:

(millions of dollars)	Maturity	Total Amount	Amount Drawn
Hydro One Inc.			
Revolving standby credit facilities	June 2024	2,300	—
Hydro One			
Five-year senior, revolving term credit facility	June 2024	250	—
Total		2,550	—

The Company may use the Operating Credit Facilities for working capital and general corporate purposes. If used, interest on the Operating 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.

Subsidiary Debt Guarantee

Hydro One Holdings Limited (HOHL) is an indirect wholly-owned subsidiary of Hydro One that may offer and sell debt securities. Any debt securities issued by HOHL are fully and unconditionally guaranteed by the Company. At December 31, 2020 and 2019, no debt securities have been issued by HOHL.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2020 and 2019:

As at December 31 (millions of dollars)	2020	2019
4.40% Series 20 notes due 2020	–	300
1.62% Series 33 notes due 2020[1]	–	350
1.84% Series 34 notes due 2021	500	500
2.57% Series 39 notes due 2021[1]	300	300
3.20% Series 25 notes due 2022	600	600
0.71% Series 48 notes due 2023	600	–
2.54% Series 42 notes due 2024	700	700
1.76% Series 45 notes due 2025	400	–
2.97% Series 40 notes due 2025	350	350
2.77% Series 35 notes due 2026	500	500
3.02% Series 43 notes due 2029	550	550
2.16% Series 46 notes due 2030	400	–
7.35% Debentures due 2030	400	400
1.69% Series 49 notes due 2031	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
3.63% Series 41 notes due 2049	750	750
2.71% Series 47 notes due 2050	500	–
3.64% Series 44 notes due 2050	250	250
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)	12,995	11,345
1.41% Series 2020-1 notes due 2027	425	–
Hydro One long-term debt (b)	425	–
6.6% Senior Secured Bonds due 2023 (Principal amount – $102 million)	113	121
4.6% Note Payable due 2023 (Principal amount – $36 million)	38	39
HOSSM long-term debt (c)	151	160
	13,571	11,505
Add: Net unamortized debt premiums	10	12
Add: Unrealized mark-to-market loss[1]	3	1
Less: Unamortized deferred debt issuance costs	(52)	(43)
Total long-term debt	13,532	11,475

1 The unrealized mark-to-market net loss of $3 million (2019 – $1 million) relates to $300 million Series 39 notes due 2021. The unrealized mark-to-market net loss is offset by a $3 million unrealized mark-to-market net gain (2019 – $1 million) 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, 2020, long-term debt of $12,995 million (2019 – $11,345 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. In April 2020, Hydro One Inc. filed a short form base shelf prospectus for its MTN Program, which has a maximum authorized principal amount of notes issuable of $4,000 million, expiring in May 2022. At December 31, 2020, $2,800 million remained available for issuance under this MTN Program prospectus.

In 2020, Hydro One Inc. issued long-term debt totalling $2,300 million (2019 – $1,500 million) and repaid long-term debt of $650 million (2019 – $728 million) under its MTN Program.

(b) Hydro One long-term debt

On August 20, 2020, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $2,000 million of debt, equity or other securities, or any combination thereof, during the 25-month period ending on September 20, 2022. At December 31, 2020, $1,575 million remained available for issuance.

In 2020, Hydro One issued $425 million of long-term debt with a maturity date of October 15, 2027 and a coupon rate of 1.41%, under the Universal Base Shelf Prospectus (2019 – $nil).

(c) HOSSM long-term debt

At December 31, 2020, HOSSM long-term debt of $151 million (2019 – $160 million), with a principal amount of $138 million (2019 – $141 million) was outstanding. In 2020, no long-term debt was issued (2019 – $nil), and $3 million (2019 – $2 million) of long-term debt was repaid.

The total long-term debt is presented on the consolidated balance sheets as follows:

As at December 31 (millions of dollars)	2020	2019
Current liabilities:		
Long-term debt payable within one year	**806**	653
Long-term liabilities:		
Long-term debt	**12,726**	10,822
Total long-term debt	**13,532**	11,475

Principal and Interest Payments

At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments (millions of dollars)	Interest Payments (millions of dollars)	Weighted-Average Interest Rate (%)
Year 1	803	498	2.1
Year 2	604	483	3.2
Year 3	731	467	1.7
Year 4	700	452	2.5
Year 5	750	434	2.3
	3,588	2,334	2.3
Years 6-10	2,275	2,004	3.3
Thereafter	7,695	4,073	4.6
	13,558	8,411	3.8

18. 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, 2020 and 2019, 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, 2020 and 2019 are as follows:

As at December 31 (millions of dollars)	**2020 Carrying Value**	**2020 Fair Value**	2019 Carrying Value	2019 Fair Value
Long-term debt measured at fair value:				
$50 million of MTN Series 33 notes	**–**	**–**	50	50
$300 million MTN Series 39 notes	**303**	**303**	301	301
Other notes and debentures	**13,229**	**16,226**	11,124	13,121
Long-term debt, including current portion	**13,532**	**16,529**	11,475	13,472

Fair Value Measurements of Derivative Instruments

Fair Value Hedges

At December 31, 2020, Hydro One Inc. had interest-rate swaps with a total notional amount of $300 million (2019 – $350 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 2% (2019 – 3%) of its total long-term debt. At December 31, 2020, Hydro One Inc. had the following interest-rate swap designated as a fair value hedge:

- a $300 million fixed-to-floating interest-rate swap agreement to convert the $300 million MTN Series 39 notes maturing June 25, 2021 into three-month variable rate debt.

Cash Flow Hedges

At December 31, 2020, Hydro One Inc. had a total of $800 million in 3-year pay-fixed, receive-floating interest-rate swap agreements designated as cash flow hedges. These cash flow hedges are intended to offset the variability of interest rates on the issuances of short-term commercial paper between January 9, 2020 and March 9, 2023.

In March 2020, Hydro One Inc. entered into $400 million of bond forward agreements. Consistent with their intention to mitigate the Company's exposure to variability in interest rates on forecasted fixed-rate long-term debt issuance, the $400 million bond forward agreements were settled upon the issuance of the Series 48 notes in October 2020, for a payment of $3 million on settlement, which is being amortized over the term of the related note.

At December 31, 2020 and 2019, the Company had no derivative instruments classified as undesignated contracts.

In October 2017, the Company entered into a Foreign-Exchange Contract to convert $1,400 million 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 Foreign-Exchange Contract was contingent on the Company closing the proposed Merger (see Note 4 – Business Combinations) and was intended to mitigate the foreign currency risk related to the portion of the Merger purchase price financed with the issuance of Convertible Debentures. This contract was an economic hedge and did not qualify for hedge accounting. It has been accounted for as an undesignated contract with changes in fair value being recorded in earnings as they occurred. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations) in January 2019, the Foreign-Exchange Contract was terminated and previously recorded unrealized gains of $22 million were reversed in financing charges in 2019. No payment was due or payable by Hydro One related to the Foreign-Exchange Contract.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2020 and 2019 is as follows:

As at December 31, 2020 (millions of dollars)	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Investments (Note 14)	**7**	**7**	**—**	**—**	**7**
Derivative instruments (Note 10)					
Fair value hedges	**3**	**3**	**—**	**3**	**—**
	10	**10**	**—**	**3**	**7**
Liabilities:					
Long-term debt, including current portion	**13,532**	**16,529**	**—**	**16,529**	**—**
Derivative instruments (Notes 15, 16)					
Cash flow hedges, including current portion	**25**	**25**	**—**	**25**	**—**
	13,557	**16,554**	**—**	**16,554**	**—**

As at December 31, 2019 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Investments (Note 14)	2	2	—	—	2
Derivative instruments (Note 14)					
Fair value hedges	1	1	—	1	—
Cash flow hedges	2	2	—	2	—
	5	5	—	3	2
Liabilities:					
Long-term debt, including current portion	11,475	13,472	—	13,472	—
	11,475	13,472	—	13,472	—

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, 2020 or 2019.

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, 2020 and 2019:

Year ended December 31 (millions of dollars)	**2020**	2019
Fair value of assets – beginning	**2**	22
Additions	**5**	2
Unrealized loss on Foreign-Exchange Contract included in financing charges (Note 4)	**—**	(22)
Fair value of assets – ending	**7**	2

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 values, 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 may utilize interest-rate swaps 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, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted 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, 2020 and 2019.

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, 2020 and 2019 were not material.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, net of tax, on the derivative instrument is recorded as OCI/OCL and is reclassified to results of operations in the same period during which the hedged transaction affects results of operations. The unrealized loss, net of tax, on the cash flow hedges for the year ended December 31, 2020 recorded in OCL was $20 million (2019 – unrealized gain of $2 million), resulting in an accumulated other comprehensive loss (AOCL) of $18 million related to cash flow hedges at December 31, 2020 (2019 – AOCI of $2 million). During the year ended December 31, 2020, a loss of $7 million was reclassified to financing charges (2019 – $nil). The Company estimates that the amount of AOCL, net of tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is $8 million. Actual amounts reclassified to results of operations depend on the interest rate risk in effect until the derivative contracts mature. For all forecasted transactions, at December 31, 2020, the maximum term over which the Company is hedging exposures to the variability of cash flows is approximately two years.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures (SIPP). Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest rate risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 20 – Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2020 and 2019, 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, 2020 and 2019, there was no material accounts receivable balance due from any single customer.

At December 31, 2020, the Company's allowance for doubtful accounts was $46 million (2019 – $22 million). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2020, approximately 4% (2019 – 5%) of the Company's net accounts receivable were outstanding for more than 60 days. Please see Note 9 – Accounts Receivable for additions to allowance for doubtful accounts related to the impact of the COVID-19 pandemic.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties on both 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 maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2020 and 2019, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2020, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, was with four financial institutions with investment grade credit ratings as counterparties.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across 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 operating liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the Operating Credit Facilities. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, and anticipated levels of funds from operations are expected to be sufficient to fund the Company's operating requirements. The Company's currently available liquidity is also expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Company's cash requirements.

On August 20, 2020, Hydro One filed a Universal Base Shelf Prospectus with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $2,000 million of debt, equity or other securities, or any combination thereof, during the 25-month period ending on September 20, 2022.

On September 21, 2020, in order to secure required funding for the redemption of the Series 1 preferred shares (Preferred Shares), Hydro One secured binding commitments for three bilateral two-year senior unsecured term credit facilities (Bilateral Credit Facilities) totalling $201 million. On October 15, 2020, these bilateral commitments were terminated upon receipt of the proceeds of Hydro One's $425 million long-term debt offering.

On December 17, 2020, HOHL filed a short form base shelf prospectus (US Debt Shelf Prospectus) with securities regulatory authorities in Canada and the US to replace a previous prospectus that expired in December 2020. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US$3,000 million of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending on January 17, 2023. At December 31, 2020, no securities have been issued under the US Debt Shelf Prospectus.

The Pension Plan's short-term liquidity is provided through cash and cash equivalents, contributions, investment income and proceeds from investment transactions. In the event that investments must be sold quickly to meet current obligations, the majority of the Pension Plan's assets are invested in securities that are traded in an active market and can be readily disposed of as liquidity needs arise.

19. 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, 2020 and 2019, the Company's capital structure was as follows:

As at December 31 (millions of dollars)	**2020**	2019
Long-term debt payable within one year	**806**	653
Short-term notes payable	**800**	1,143
Less: cash and cash equivalents	**(757)**	(30)
	849	1,766
Long-term debt	**12,726**	10,822
Preferred shares	**—**	418
Common shares	**5,678**	5,661
Retained earnings	**4,838**	3,667
Total capital	**24,091**	22,334

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. 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, 2020, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

20. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a 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 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 up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. Hydro One contributions to the DC Plan for the year ended December 31, 2020 were $2 million (2019 – $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 United Professionals (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 reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total annual cash Pension Plan employer contributions for 2020 were $57 million (2019 – $61 million). Estimated annual Pension Plan employer contributions for the years 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $59 million, $93 million, $107 million, $111 million, $111 million, $113 million and $118 million, respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the 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 and post-retirement benefit obligations is generally recognized over the expected average remaining service period of the employees and using the corridor approach for the post-retirement benefit plan. For post-employment benefit plan, the impact of changes in assumptions are recognized immediately in the net periodic benefit cost. The measurement date for the Plans is December 31.

The following tables provide the components of the unfunded status of the Company's Plans at December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)	Pension Benefits 2020	Pension Benefits 2019	Post-Retirement and Post-Employment Benefits 2020	Post-Retirement and Post-Employment Benefits 2019
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**8,973**	7,752	**1,783**	1,465
Current service cost	**215**	145	**70**	56
Employee contributions	**56**	55	**—**	—
Interest cost	**284**	303	**58**	60
Benefits paid	**(381)**	(371)	**(45)**	(47)
Net actuarial loss (gain)	**465**	1,089	**(42)**	243
Transfers from other plans[1,2]	**151**	—	**33**	6
Projected benefit obligation, end of year	**9,763**	8,973	**1,857**	1,783
Change in plan assets				
Fair value of plan assets, beginning of year	**7,848**	7,205	**—**	—
Actual return on plan assets	**425**	922	**—**	—
Benefits paid	**(381)**	(371)	**(45)**	(47)
Employer contributions	**57**	61	**45**	47
Employee contributions	**56**	55	**—**	—
Administrative expenses	**(22)**	(24)	**—**	—
Transfers from other plans[2]	**120**	—	**—**	—
Fair value of plan assets, end of year	**8,103**	7,848	**—**	—
Unfunded status	**1,660**	1,125	**1,857**	1,783

1 In 2019, liabilities associated with the HOSSM post-employment benefit plans were transferred to the Hydro One post-employment benefit plans.

2 See below for information related to the transfers from other plans in 2020.

Transfers from Other Plans

Effective March 1, 2018, certain employees who provided customer service operations for Hydro One through Inergi LP were transferred to Hydro One Networks (Transferred Employees), and began accruing pension and OPEB in the Pension Plan and post-retirement and post-employment benefit plans, respectively. Pursuant to the arrangement, Inergi LP, Vertex Customer Management (Canada) Ltd. (Vertex) and Hydro One Networks agreed to transfer the defined benefit assets and related pension obligations (for current and former members) of the Inergi LP Customer Service Operations Pension Plan and the Vertex Customer Management (Canada) Limited Pension Plan to the Pension Plan. In addition, Inergi LP, Vertex and Hydro One Networks agreed to transfer the OPEB liability related to the Transferred Employees to Hydro One's post-retirement and post-employment benefit plans. Regulatory approval for the pension transfer was received on November 27, 2019.

The transfer of the pension assets of $120 million and related pension obligations of $151 million was completed on March 2, 2020. The unfunded status of $31 million was recorded as a pension benefit liability with an offsetting pension benefit regulatory asset. The transfer of the OPEB liability of $33 million was completed on April 1, 2020. The liability was recorded as a post-retirement and post-employment benefit liability with an offset to OCL. In addition, as a part of the transfers, cash totalling $24 million was transferred to Hydro One and recorded as an asset with an offset to OCI. Both, the OCI resulting from the transfer of the cash asset and the OCL resulting from the transfer of the other post-retirement benefit liability are being recognized in net income over the expected average remaining service lifetime (EARSL) of the Transferred Employees.

Hydro One presents its benefit obligations and plan assets net on its consolidated balance sheets as follows:

As at December 31 (millions of dollars)	Pension Benefits 2020	Pension Benefits 2019	Post-Retirement and Post-Employment Benefits 2020	Post-Retirement and Post-Employment Benefits 2019
Other assets[1]	**6**	3	**—**	—
Accrued liabilities	**—**	—	**60**	60
Pension benefit liability	**1,660**	1,125	**—**	—
Post-retirement and post-employment benefit liability	**—**	—	**1,797**	1,723
Net unfunded status	**1,654**	1,122	**1,857**	1,783

1 Represents the funded status of HOSSM defined benefit pension plan.

The funded or unfunded status of the Plans refers to the difference between the fair value of plan assets and the PBO 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 PBO, accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

As at December 31 (millions of dollars)	2020	2019
PBO	**9,763**	8,973
ABO	**8,817**	8,183
Fair value of plan assets	**8,103**	7,848

On an ABO basis, the Pension Plan was funded at 92% at December 31, 2020 (2019 – 96%). On a PBO basis, the Pension Plan was funded at 83% at December 31, 2020 (2019 – 87%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2020 and 2019 for the Pension Plan:

Year ended December 31 (millions of dollars)	2020	2019
Current service cost	**215**	145
Interest cost	**284**	303
Expected return on plan assets, net of expenses	**(450)**	(462)
Prior service cost amortization	**2**	—
Amortization of actuarial losses	**95**	55
Net periodic benefit costs	**146**	41
Charged to results of operations[1]	**25**	30

1 The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2020, pension costs of $69 million (2019 – $73 million) were attributed to labour, of which $25 million (2019 – $30 million) was charged to operations, and $44 million (2019 – $43 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, 2020 and 2019 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of dollars)	2020	2019
Current service cost	**70**	56
Interest cost	**58**	60
Prior service cost amortization	**2**	—
Amortization of actuarial losses	**5**	7
Net periodic benefit costs	**135**	123
Charged to results of operations[1,2]	**73**	50

1 The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2020, post-retirement and post-employment costs of $135 million (2019 – $123 million) were attributed to labour, of which $73 million (2019 – $50 million) was charged to operations, $17 million (2019 – $39 million) was recorded in the Hydro One Networks distribution post-retirement and post-employment benefits non-service cost regulatory asset, and $45 million (2019 – $34 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

2 In the 2020-2022 Transmission Decision, the OEB approved the recovery of the non-service cost component of post-retirement and post-employment benefits as part of operation, maintenance and administration costs for the Company's transmission business. These costs were previously capitalized and recovered through rate base. As a result, during the year ended December 31, 2020, additional other post-retirement and post-employment costs of $22 million attributed to labour were charged to operations.

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, 2020 and 2019:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2020**	2019	**2020**	2019
Significant assumptions:				
Weighted average discount rate	**2.60%**	3.10%	**2.60%**	3.10%
Rate of compensation scale escalation (long-term)	**2.25%**	2.50%	**2.25%**	2.50%
Rate of cost of living increase	**1.75%**	2.00%	**1.75%**	2.00%
Rate of increase in health care cost trends[1]	**—**	—	**3.70%**	4.04%

1 4.74% per annum in 2021, grading down to 3.70% per annum in and after 2031 (2019 – 5.09% per annum in 2020, grading down to 4.04% 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, 2020 and 2019. 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	**2020**	2019
Pension Benefits:		
Weighted average expected rate of return on plan assets	**5.75%**	6.50%
Weighted average discount rate	**3.10%**	3.90%
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	**3.10%**	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)	**15.5**	15.5
Rate of increase in health care cost trends[1]	**4.04%**	4.04%

1 5.09% per annum in 2020, grading down to 4.04% per annum in and after 2031 (2019 – 5.19% per annum in 2019, grading down to 4.04% 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 PBO for the post-retirement and post-employment benefits at December 31, 2020 and 2019 is as follows:

As at December 31 (millions of dollars)	2020	2019
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**311**	281
Effect of a 1% decrease in health care cost trends	**(234)**	(213)

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, 2020 and 2019 is as follows:

Year ended December 31 (millions of dollars)	2020	2019
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**27**	21
Effect of a 1% decrease in health care cost trends	**(19)**	(16)

The following approximate life expectancies were used in the mortality assumptions to determine the PBO for the pension and post-retirement and post-employment plans at December 31, 2020 and 2019:

As at December 31	2020	2019
Life expectancy at age 65 for a member currently at:	(years)	(years)
Age 65 – male	**22**	22
Age 65 – female	**25**	25
Age 45 – male	**23**	23
Age 45 – female	**26**	26

Estimated Future Benefit Payments

At December 31, 2020, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2021	352	60
2022	360	61
2023	366	62
2024	371	62
2025	375	64
2026 through to 2030	1,927	326
Total estimated future benefit payments through to 2030	3,751	635

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. These amounts are reflected in the following table:

Year ended December 31 (millions of dollars)	2020	2019
Pension Benefits:		
Actuarial loss for the year	**536**	652
Prior service cost for the year	**31**	—
Amortization of actuarial losses	**(95)**	(55)
Amortization of prior service cost	**(2)**	—
	470	597
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	**(44)**	242
Amortization of actuarial losses	**(2)**	(7)
	(46)	235

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, 2020 and 2019:

Year ended December 31 (millions of dollars)	2020	2019
Pension Benefits:		
Actuarial loss	**1,660**	1,125
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	**59**	105

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
As at December 31 (millions of dollars)	**2020**	2019	**2020**	2019
Prior service cost	**2**	—	**4**	—
Actuarial loss	**124**	95	**2**	2

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 it comes 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 fulfils its primary objective by adhering to specific investment policies outlined in its Statement of Investment Policies and Procedures (SIPP), which is reviewed and approved annually by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging external investment managers who are charged with the fiduciary 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 underlying investment 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, 2020, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	45	51
Debt securities	35	35
Real Estate and Infrastructure	20	14
	100	100

At December 31, 2020, the Pension Plan held $23 million (2019 – $21 million) Hydro One corporate bonds and $565 million (2019 – $504 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, 2020 and 2019. 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, 2020 and 2019, 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 and liabilities measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2020 and 2019:

As at December 31, 2020 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	**—**	**21**	**1,429**	**1,450**
Cash and cash equivalents	**163**	**—**	**—**	**163**
Short-term securities	**—**	**175**	**—**	**175**
Derivative instruments	**—**	**2**	**—**	**2**
Corporate shares – Canadian	**142**	**—**	**—**	**142**
Corporate shares – Foreign	**3,335**	**209**	**—**	**3,544**
Bonds and debentures – Canadian	**—**	**2,499**	**—**	**2,499**
Bonds and debentures – Foreign	**—**	**96**	**—**	**96**
Total fair value of plan assets[1]	**3,640**	**3,002**	**1,429**	**8,071**
Derivative instruments	**—**	**1**	**—**	**1**
Total fair value of plan liabilities[1]	**—**	**1**	**—**	**1**

1 At December 31, 2020, the total fair value of Pension Plan assets and liabilities excludes $39 million of interest and dividends receivable, $6 million of pension administration expenses payable, $2 million of taxes payable, $6 million payable to participants, $17 million of sold investments receivable, and $9 million of purchased investments payable.

As at December 31, 2019 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	22	1,079	1,101
Cash and cash equivalents	159	—	—	159
Short-term securities	—	98	—	98
Derivative instruments	—	5	—	5
Corporate shares – Canadian	107	—	—	107
Corporate shares – Foreign	3,545	219	—	3,764
Bonds and debentures – Canadian	—	2,427	—	2,427
Bonds and debentures – Foreign	—	165	—	165
Total fair value of plan assets[1]	3,811	2,936	1,079	7,826
Derivative instruments	—	2	—	2
Total fair value of plan liabilities[1]	—	2	—	2

1 At December 31, 2019, the total fair value of Pension Plan assets and liabilities excludes $36 million of interest and dividends receivable, $10 million of pension administration expenses payable, $3 million of sold investments receivable, and $5 million of purchased investments payable.

See Note 18 – 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, 2020 and 2019. 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 could, therefore, include changes in fair value based on both observable and unobservable inputs. The Level 3 financial instruments are comprised of pooled funds whose valuations are provided by the investment managers. Sensitivity analysis is not provided as the underlying assumptions used by the investment managers are not available.

Year ended December 31 (millions of dollars)	**2020**	2019
Fair value, beginning of year	**1,079**	651
Realized and unrealized gains (losses)	**97**	(4)
Purchases	**288**	463
Sales and disbursements	**(35)**	(31)
Fair value, end of year	**1,429**	1,079

There were no significant transfers between any of the fair value levels during the years ended December 31, 2020 and 2019.

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 are expected to 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, real estate 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 notional principal amount of contracts outstanding as at December 31, 2020 was $423 million (2019 – $742 million), the most significant currencies being hedged against the Canadian dollar are the United States dollar, euro, British pound sterling, Swedish krona and Japanese yen. The net realized loss on contracts for the year ended December 31, 2020 was $8 million (2019 – $1 million net realized gain). The terms to maturity of the forward exchange contracts at December 31, 2020 are within three months. 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. Corporate shares which are valued based on quoted prices in active markets, but held within a pension investment holding company, are categorized as Level 2. 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.

21. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 (millions of dollars)	PCB	LAR	Total
Environmental liabilities – beginning	**90**	**51**	**141**
Interest accretion	**3**	**—**	**3**
Expenditures	**(17)**	**(6)**	**(23)**
Revaluation adjustment	**—**	**12**	**12**
Environmental liabilities – ending	**76**	**57**	**133**
Less: current portion	**(25)**	**(8)**	**(33)**
	51	**49**	**100**

Year ended December 31, 2019 (millions of dollars)	PCB	LAR	Total
Environmental liabilities – beginning	108	57	165
Interest accretion	4	—	4
Expenditures	(17)	(8)	(25)
Revaluation adjustment	(5)	2	(3)
Environmental liabilities – ending	90	51	141
Less: current portion	(19)	(11)	(30)
	71	40	111

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:

As at December 31, 2020 (millions of dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	**80**	**57**	**137**
Less: discounting environmental liabilities to present value	**(4)**	**—**	**(4)**
Discounted environmental liabilities	**76**	**57**	**133**

As at December 31, 2019 (millions of dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	97	51	148
Less: discounting environmental liabilities to present value	(7)	—	(7)
Discounted environmental liabilities	90	51	141

At December 31, 2020, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2021	33
2022	31
2023	15
2024	14
2025	10
Thereafter	34
	137

Hydro One records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% 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.

At December 31, 2020, the Company's best estimate of the total estimated future expenditures to comply with current PCB regulations was $80 million (2019 – $97 million). These expenditures are expected to be incurred over the period from 2021 to 2025. As a result of its annual review of environmental liabilities, no revaluation adjustment to the PCB environmental liability was recorded in 2020 (2019 – revaluation adjustment was recorded to decrease the PCB environmental liability by $5 million).

LAR

At December 31, 2020, the Company's best estimate of the total estimated future expenditures to complete its LAR program was $57 million (2019 – $51 million). These expenditures are expected to be incurred over the period from 2021 to 2057. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2020 to increase the LAR environmental liability by $12 million (2019 – $2 million).

22. 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 2.0% to 4.0%, 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. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2020 to increase the assets retirement liability by $3 million (2019 – no revaluation adjustment to the asset retirement obligations was recorded).

At December 31, 2020, Hydro One had recorded asset retirement obligations of $13 million (2019 – $10 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.

23. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have terms between three and seven years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. 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. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Company's operating leases was as follows:

Year ended December 31 (millions of dollars)	**2020**	2019
Lease expense	**14**	10
Lease payments made	**13**	8

As at December 31	**2020**	2019
Weighted-average remaining lease term[1] (years)	**7**	8
Weighted-average discount rate	**2.6%**	2.7%

1 Includes renewal options that are reasonably certain to be exercised.

At December 31, 2020, future minimum operating lease payments were as follows:

(millions of dollars)	
2021	**16**
2022	**13**
2023	**12**
2024	**12**
2025	**10**
Thereafter	**27**
Total undiscounted minimum lease payments	**90**
Less: discounting minimum lease payments to present value	**(8)**
Total discounted minimum lease payments	**82**

At December 31, 2019, future minimum operating lease payments were as follows:

(millions of dollars)	
2020	12
2021	12
2022	11
2023	10
2024	9
Thereafter	33
Total undiscounted minimum lease payments[1]	87
Less: discounting minimum lease payments to present value	(9)
Total discounted minimum lease payments	78

1 Excludes committed amounts of $6 million for leases that have not yet commenced.

Hydro One presents its ROU assets and lease obligations on the consolidated balance sheets as follows:

As at December 31 (millions of dollars)	**2020**	2019
Other long-term assets (Note 14)	**77**	75
Accounts payable and other current liabilities (Note 15)	**12**	9
Other long-term liabilities (Note 16)	**70**	69

24. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2020, the Company had 597,611,787 (2019 – 596,818,436) 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 presents the changes to common shares during the years ended December 31, 2020 and 2019:

	Ownership by		
Year ended December 31, 2020 (number of shares)	**Public**	**Province**	**Total**
Common shares – beginning	**314,405,788**	**282,412,648**	**596,818,436**
Common shares issued – LTIP[1]	**351,789**	**—**	**351,789**
Common shares issued – share grants[2]	**441,562**	**—**	**441,562**
Common shares – ending	**315,199,139**	**282,412,648**	**597,611,787**
	52.7%	**47.3%**	**100%**

1 In 2020, Hydro One issued from treasury 351,789 common shares in accordance with provisions of the LTIP. This included the exercise of 294,840 stock options for $7 million.

2 In 2020, Hydro One issued from treasury 441,562 common shares in accordance with provisions of the Power Workers' Union (PWU) and the Society Share Grant Plans.

	Ownership by		
Year ended December 31, 2019 (number of shares)	Public	Province	Total
Common shares – beginning	313,526,327	282,412,648	595,938,975
Common shares issued – LTIP[1]	416,519	—	416,519
Common shares issued – share grants[2]	462,942	—	462,942
Common shares – ending	314,405,788	282,412,648	596,818,436
	52.7%	47.3%	100%

1 In 2019, Hydro One issued from treasury 416,519 common shares in accordance with provisions of the LTIP. This included the exercise of 302,520 stock options for cash proceeds of $6 million.

2 In 2019, Hydro One issued from treasury 462,942 common shares in accordance with provisions of the PWU and the Society Share Grant Plans.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2020 and 2019, two series of preferred shares were authorized for issuance: the Series 1 preferred shares (Preferred Shares) and the Series 2 preferred shares. At December 31, 2020, the Company had no Preferred Shares (2019 – 16,720,000) and no Series 2 preferred shares (2019 – nil) issued and outstanding.

On November 20, 2020, Hydro One exercised its option to redeem all of its 16,720,000 outstanding Preferred Shares in accordance with their terms. The Preferred Shares were redeemed at a price of $25.00 per share, plus all accrued and unpaid dividends up to, but excluding November 20, 2020, for an aggregate redemption price of $423 million, including $418 million Preferred Shares balance and $5 million for accrued dividends. The Preferred Shares were not exchangeable or convertible into the common shares of the Company and the redemption had no impact on the Province's voting rights or ownership percentage of the outstanding common shares of Hydro One.

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 Preferred Shares and ending on and including November 19, 2020, the holders of the Preferred Shares were 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.

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.

25. DIVIDENDS

In 2020, preferred share dividends in the amount of $18 million (2019 – $18 million) and common share dividends in the amount of $599 million (2019 – $570 million) were declared and paid.

See Note 34 – Subsequent Events for dividends declared subsequent to December 31, 2020.

26. 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	**2020**	2019
Net income attributable to common shareholders (millions of dollars)	**1,770**	778
Weighted-average number of shares		
Basic	**597,421,127**	596,437,577
Effect of dilutive stock-based compensation plans	**2,497,161**	2,410,860
Diluted	**599,918,288**	598,848,437
EPS		
Basic	**$ 2.96**	$ 1.30
Diluted	**$ 2.95**	$ 1.30

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS for the year ended December 31, 2019, as conditions for closing the Merger were not met. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), the Convertible Debentures were redeemed on February 8, 2019.

27. 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 its Initial Public Offering (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 its 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 2020, 441,562 common shares (2019 – 462,942) were issued under the Share Grant Plans. Total share-based compensation recognized during 2020 was $7 million (2019 – $9 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during the years ended December 31, 2020 and 2019 is presented below:

Year ended December 31, 2020	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	**3,674,377**	**$ 20.50**
Vested and issued[1]	**(441,562)**	**—**
Forfeited	**(78,010)**	**$ 20.50**
Share grants outstanding – ending	**3,154,805**	**$ 20.50**

1 In 2020, Hydro One issued from treasury 441,562 common shares to eligible employees in accordance with provisions of the Share Grant Plans.

Year ended December 31, 2019	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	4,234,155	$ 20.50
Vested and issued[1]	(462,942)	—
Forfeited	(96,836)	$ 20.50
Share grants outstanding – ending	3,674,377	$ 20.50

1 In 2019, Hydro One issued from treasury 462,942 common shares to eligible employees in accordance with provisions of the Share Grant Plans.

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.

A summary of DSU awards activity under the Directors' DSU Plan during the years ended December 31, 2020 and 2019 is presented below:

Year ended December 31 (number of DSUs)	2020	2019
DSUs outstanding – beginning	**52,620**	46,697
Granted	**22,481**	29,938
Settled	**(9,861)**	(24,015)
DSUs outstanding – ending	**65,240**	52,620

For the year ended December 31, 2020, an expense of $1 million (2019 – $1 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2020, a liability of $2 million (2019 – $1 million) related to Directors' DSUs has been recorded at the closing price of the Company's common shares of $28.65. This liability is included in other long-term 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.

A summary of DSU awards activity under the Management DSU Plan during the years ended December 31, 2020 and 2019 is presented below:

Year ended December 31 (number of DSUs)	2020	2019
DSUs outstanding – beginning	**52,186**	108,296
Granted	**22,132**	24,996
Paid	**(12,438)**	(81,106)
DSUs outstanding – ending	**61,880**	52,186

For the year ended December 31, 2020, an expense of $1 million (2019 – $1 million) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2020, a liability of $2 million (2019 – $1 million) related to Management DSUs has been recorded at the closing price of the Company's common shares of $28.65. This liability is included in other long-term 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 2020, Company contributions made under the ESOP were $2 million (2019 – $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 which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. 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, including Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2020 and 2019 is presented below:

	PSUs		RSUs	
Year ended December 31 (number of units)	**2020**	2019	**2020**	2019
Units outstanding – beginning	**171,344**	605,180	**206,993**	442,470
Vested and issued	**(52,627)**	(78,121)	**(3,728)**	(92,112)
Forfeited	**(6,797)**	(153,805)	**(7,125)**	(84,745)
Settled	**—**	(201,910)	**(56,410)**	(58,620)
Units outstanding – ending[1]	**111,920**	171,344	**139,730**	206,993

1 Units outstanding at December 31, 2020 include 12,980 RSUs (2019 – 7,740 PSUs and 96,330 RSUs) that may be settled in cash if certain conditions are met. At December 31, 2020, a liability of $1 million (2019 – $3 million) has been recorded with respect to these awards and is included in accounts payable and other current liabilities on the consolidated balance sheets.

No awards were granted in 2020 or 2019. The compensation expense related to the PSU and RSU awards recognized by the Company during 2020 was $3 million (2019 – $9 million).

Stock Options

The Company is authorized to grant stock options under its LTIP to certain eligible employees. No stock options were granted in 2020 or 2019. The stock options previously granted are exercisable for a period not to exceed seven years from the date of grant. The original three-year vesting period for 706,070 stock options was modified in 2019 due to agreements reached with five option-holders, resulting in applicable stock options being fully vested in 2019. The incremental compensation cost resulting from the modification was not significant. There was no modification of stock options in 2020.

The fair value-based method is used to measure compensation expense related to stock options and the expense was recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model. Updates related to stock options subject to modification were not significant.

A summary of stock options activity during the years ended December 31, 2020 and 2019 is presented below:

	Number of Stock Options	Weighted-average exercise price
Stock options outstanding – January 1, 2019	949,910	$ 20.72
Exercised[1]	(302,520)	$ 20.76
Forfeited[4]	(243,840)	$ 20.75
Stock options outstanding – December 31, 2019[2,3]	403,550	$ 20.66
Exercised[1]	(294,840)	$ 20.66
Stock options outstanding – December 31, 2020[2,3]	108,710	$ 20.66

1 Stock options exercised in 2020 had an aggregate intrinsic value of $2 million (2019 – $1 million).

2 During 2020, no stock options vested (2019 – 706,070 stock options vested with a modified fair value of $1.04 per option), and 294,840 (2019 – 302,520) stock options were exercised. At December 31, 2020 and 2019, all stock options outstanding were vested and exercisable.

3 Stock options outstanding at December 31, 2020 have an aggregate intrinsic value of $1 million (2019 – $2 million) and weighted-average remaining contractual term of 4.2 years (2019 – 5.2 years).

4 Stock options forfeited in 2019 had a fair value of $1.65 per option.

No compensation expense related to stock options was recognized by the Company during 2020 (2019 – $1 million).

28. NONCONTROLLING INTEREST

Total noncontrolling interest consists of noncontrolling interest attributable to B2M LP and NRLP. The following tables show the movements in total noncontrolling interest during the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 (millions of dollars)	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest – beginning	**20**	**59**	**79**
Contributions from sale of noncontrolling interest (Note 4)	**—**	**9**	**9**
Distributions to noncontrolling interest	**—**	**(2)**	**(2)**
Net income attributable to noncontrolling interest	**2**	**6**	**8**
Noncontrolling interest – ending	**22**	**72**	**94**

Year ended December 31, 2019 (millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	21	49	70
Contributions from sale of noncontrolling interest (Note 4)	—	12	12
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	20	59	79

B2M LP

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 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 B2M LP noncontrolling interest during the years ended December 31, 2020 and 2019:

Year ended December 31, 2020 (millions of dollars)	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest – beginning	**20**	**47**	**67**
Distributions to noncontrolling interest	**—**	**(2)**	**(2)**
Net income attributable to noncontrolling interest	**2**	**4**	**6**
Noncontrolling interest – ending	**22**	**49**	**71**

Year ended December 31, 2019 (millions of dollars)	Temporary Equity	Total	Equity
Noncontrolling interest – beginning	21	49	70
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	20	47	67

NRLP

On September 18, 2019, Hydro One Networks sold to the Six Nations of the Grand River Development Corporation and, through a trust, to the Mississaugas of the Credit First Nation a 25.0% and 0.1%, respectively, equity interest in NRLP partnership units for total consideration of $12 million, representing the fair value of the equity interest acquired. On January 31, 2020, the Mississaugas of the Credit First Nation purchased an additional 19.9% equity interest in NRLP partnership units from Hydro One Networks for total cash consideration of $9 million. Following this transaction, Hydro One's interest in the equity portion of NRLP partnership units was reduced to 55%, with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation owning 25% and 20%, respectively, of the equity interest in NRLP partnership units. The First Nations Partners' noncontrolling interest in NRLP is classified within equity.

The following table shows the movements in NRLP noncontrolling interest during the years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)	**2020**	2019
Noncontrolling interest – beginning	**12**	—
Contributions from sale of noncontrolling interest (Note 4)	**9**	12
Net income attributable to noncontrolling interest	**2**	—
Noncontrolling interest – ending	**23**	12

29. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.3% ownership at December 31, 2020. 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 Ministry of Energy. Ontario Charging Network LP (OCN LP) is a joint-venture limited partnership between a subsidiary of Hydro One and OPG. The following is a summary of the Company's related party transactions during the years ended December 31, 2020 and 2019:

Year ended December 31 (millions of dollars)

Related Party	Transaction	**2020**	2019
Province	Dividends paid[1]	**301**	288
IESO	Power purchased	**2,506**	1,808
	Revenues for transmission services	**1,717**	1,636
	Amounts related to electricity rebates	**1,588**	692
	Distribution revenues related to rural rate protection	**242**	240
	Distribution revenues related to supply of electricity to remote northern communities	**35**	35
	Funding received related to CDM programs	**26**	42
OPG[2]	Power purchased	**6**	8
	Revenues related to provision of services and supply of electricity	**8**	9
	Capital contribution received from OPG	**3**	—
	Costs related to the purchase of services	**3**	1
OEFC	Power purchased from power contracts administered by the OEFC	**1**	2
OEB	OEB fees	**9**	9
OCN LP[3]	Investment in OCN LP	**2**	2

1 On November 20, 2020 Hydro One redeemed the Preferred Shares held by the Province. See Note 24 – Share Capital.

2 OPG has provided a $2.5 million guarantee to Hydro One related to the OCN Guarantee. See Note 32 – Commitments for details related to the OCN Guarantee.

3 OCN LP owns and operates electric vehicle fast charging stations across Ontario, under the Ivy Charging Network brand.

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. Invoices are issued monthly, and amounts are due and paid on a monthly basis.

30. 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)	**2020**	2019
Accounts receivable (Note 9)[1]	**12**	(73)
Due from related parties	**89**	(160)
Materials and supplies (Note 10)[1]	**—**	(1)
Prepaid expenses and other assets (Note 10)[1]	**(9)**	(8)
Other long-term assets (Note 14)	**(1)**	(2)
Accounts payable (Note 15)[1]	**37**	7
Accrued liabilities (Note 15)[1]	**(62)**	38
Due to related parties	**27**	213
Accrued interest (Note 15)	**14**	8
Long-term accounts payable and other long-term liabilities (Note 16)[1]	**1**	—
Post-retirement and post-employment benefit liability (Note 16)	**72**	33
	180	55

1 Adjusted for amounts related to acquisitions. See Note 4 – Business Combinations for more details.

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the consolidated statements of cash flows for the years ended December 31, 2020 and 2019. The reconciling items include net change in accruals and capitalized depreciation.

Year ended December 31, 2020 (millions of dollars)	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	**(1,751)**	**(127)**	**(1,878)**
Reconciling items	**33**	**1**	**34**
Cash outflow for capital expenditures	**(1,718)**	**(126)**	**(1,844)**

Year ended December 31, 2019 (millions of dollars)	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,551)	(116)	(1,667)
Reconciling items	38	1	39
Cash outflow for capital expenditures	(1,513)	(115)	(1,628)

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 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 2020, there were no capital contributions from these assessments (2019 – $3 million). In 2019, this represented 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)	2020	2019
Net interest paid	**493**	494
Income taxes paid	**30**	21

31. 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.

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 2020, the Company paid approximately $2 million (2019 – $2 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.

32. COMMITMENTS

The following table presents a summary of Hydro One's commitments under outsourcing and other agreements due in the next five years and thereafter:

As at December 31, 2020 (millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing and other agreements	106	15	11	13	2	15
Long-term software/meter agreement	8	2	1	2	—	—

Outsourcing and Other Agreements

Hydro One has an agreement with Inergi LP for the provision of back-office and IT outsourcing services, including supply chain, pay operations, IT, and finance and accounting services. The agreement expires on February 28, 2021 for IT services and expires on October 31, 2021 for supply chain services. The agreement for pay operations, and for finance and accounting services was extended in October 2020 and now expires on December 31, 2021. In February 2021, Hydro One entered into an agreement for information technology services with Capgemini Canada Inc., which expires on February 29, 2024, and includes an option to extend for two additional one-year terms at Hydro One's discretion. Effective January 1, 2022, Ceridian Canada Ltd. will replace Inergi LP as the new provider of pay operations for a five-year term.

BGIS Global Integrated Solutions Canada LP (BGIS) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with BGIS for these services expires in December 2024, with an option for the Company to renew the agreement for an additional term of three years.

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, with an option for the Company to renew the agreement for an additional term of five years.

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next five years and thereafter:

As at December 31, 2020 (millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating Credit Facilities	—	—	—	2,550	—	—
Letters of credit[1]	194	2	—	—	—	—
Guarantees[2]	491	—	—	—	—	—

1 Letters of credit consist of $167 million letters of credit related to retirement compensation arrangements, a $22 million letter of credit provided to the IESO for prudential support, $4 million in letters of credit to satisfy debt service reserve requirements, and $3 million in letters of credit for various operating purposes.

2 Guarantees consist of $484 million prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries, and guarantees totalling $7 million provided by Hydro One to the Minister of Natural Resources (Canada) relating to OCN LP (OCN Guarantee). The OPG has provided a $2.5 million guarantee to Hydro One related to the OCN Guarantee.

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. A bank letter of credit has also been issued to provide security for Hydro One's retirement compensation arrangement trust agreement.

33. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting 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 Other Segment includes a portion of the deferred tax asset which arose from the revaluation of the tax bases of Hydro One's assets to fair market value when the Company transitioned from the provincial payments in lieu of tax regime to the federal tax regime at the time of Hydro One's initial public offering in 2015. This deferred tax asset is not required to be shared with ratepayers, the Company considers it to not be part of the regulated transmission and distribution segment assets, and it is included in the other segment.

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 tax expense from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2020 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	**1,740**	**5,507**	**43**	**7,290**
Purchased power	**—**	**3,854**	**—**	**3,854**
Operation, maintenance and administration	**391**	**619**	**60**	**1,070**
Depreciation, amortization and asset removal costs	**459**	**417**	**8**	**884**
Income (loss) before financing charges and income tax expense	**890**	**617**	**(25)**	**1,482**
Capital investments	**1,157**	**712**	**9**	**1,878**

Year ended December 31, 2019 (millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	1,652	4,788	40	6,480
Purchased power	—	3,111	—	3,111
Operation, maintenance and administration	355	610	216	1,181
Depreciation, amortization and asset removal costs	462	409	7	878
Income (loss) before financing charges and income tax expense	835	658	(183)	1,310
Capital investments	1,035	624	8	1,667

Total Assets by Segment:

As at December 31 (millions of dollars)	**2020**	2019
Transmission	**17,761**	15,029
Distribution	**11,387**	10,017
Other	**1,146**	2,015
Total assets	**30,294**	27,061

Total Goodwill by Segment:

As at December 31 (millions of dollars)	**2020**	2019
Transmission	**157**	157
Distribution (Note 4)	**216**	168
Total goodwill	**373**	325

All revenues, assets and substantially all costs, as the case may be, are earned, held or incurred in Canada.

34. SUBSEQUENT EVENTS

Dividends

On February 23, 2021, common share dividends of $152 million ($0.2536 per common share) were declared.

Corporate and Shareholder Information

Corporate Office
483 Bay Street, South Tower
Toronto, ON M5G 2P5
1.416.345.5000

www.HydroOne.com

Customer Inquiries
Customer Service: 1.888.664.9376

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
Institutional investors, securities analysts and others requiring additional financial information can visit www.HydroOne.com/Investors or contact us at: 1.416.345.6867
Investor.Relations@HydroOne.com or
OJaved@HydroOne.com

Media Inquiries
1.416.345.6868 or 1.877.506.7584
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 impacts on both. To learn more, visit www.hydroone.com/sustainability or email Sustainability@HydroOne.com

Stock Exchange Listing
Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

H
LISTED
TSX

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
Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of www.HydroOne.com/Investors where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, sustainability and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

Common Share Dividend Information
2021 Expected Dividend Dates

Declaration Date	Record Date	Payment Date
February 23, 2021	March 17, 2021	March 31, 2021
May 6, 2021	June 9, 2021	June 30, 2021
August 9, 2021	September 8, 2021	September 30, 2021
November 8, 2021	December 8, 2021	December 31, 2021

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 maintaining and enhancing constructive 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

Canada Energy Regulator | Régie de l'énergie du Canada

Canadian Energy Regulator
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

NPCC, Inc.

Northeast Power Coordinating Council
Northeastern North American grid reliability, standards, compliance

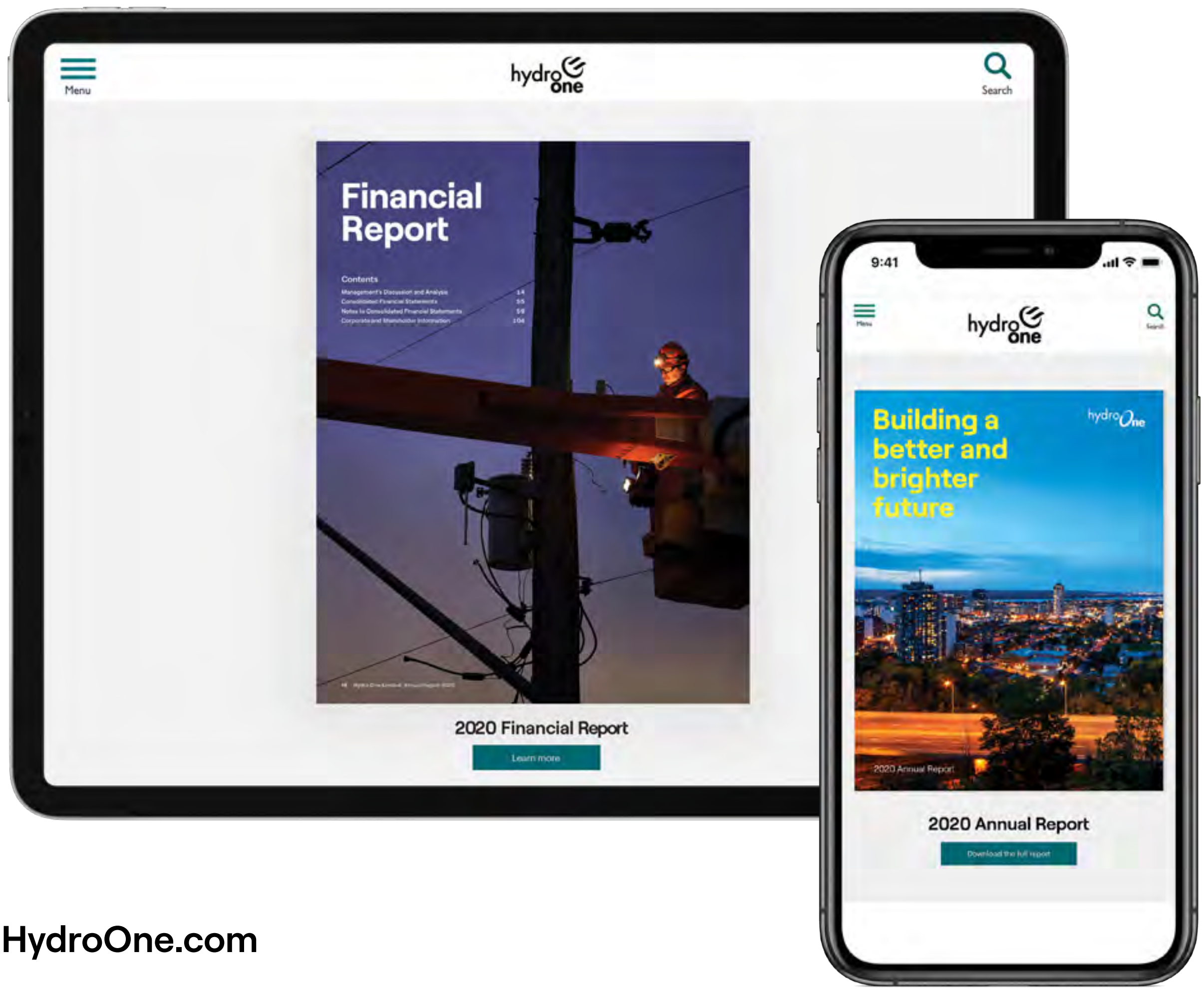
For more information, visit
www.HydroOne.com/Regulatory

Design: Craib Design & Communications www.craib.com Printed in Canada

MIX
Paper from responsible sources
FSC® C101537

Why Invest in Hydro One?

- Utility business in a stable and rate-regulated environment
- Pure-play electric company with no commodity price exposure
- Solid investment grade balance sheet
- Fully independent Board
- Stable and growing dividend



www.HydroOne.com

Follow Hydro One

Twitter @hydroone

Facebook @hydrooneofficial

Instagram @hydrooneofficial

Linkedin /company/hydro-one

IDENTIFYING CUSTOMER NEEDS

Details on how Hydro One identifies and addresses customer needs are included in:

- In Section 1.2 of the System Plans Framework (SPF) at Exhibit B-01-01 which describes the regional planning process;
- Section 1.6 of the SPF at Exhibit B-01-01 which describes Hydro One's ongoing customer engagement activities as well as a comprehensive customer engagement study conducted by Innovative Research Group specifically for this Application; and
- Attachment 1 to this exhibit (Appendix 2-AC of Chapter 2 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications*).

This page left blank intentionally.

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Hydro One's Phase 1 customer engagement process was conducted in late 2019 to early 2020. Customers were surveyed through: · focus group sessions · phone surveys · in-depth interviews · an online survey	Phase I of the Customer Engagement Study focussed on customers' general need and outcome preferences for the electricity system. Customers expressed high levels of satisfaction with the electricity service they receive and identified nine outcomes they felt are important for Hydro One, with price, reliability, safety and customer service listed as the top priorities across all customer segments. Customers also support investments in reliability and technology to reduce costs and help manage their electricity usage. Customers had the opportunity to provide their feedback on a number of high-level investment trade-offs in Phase 1 as well. For purposes of this portion of the engagement, Hydro One's planners identified a range of example types of investments that have typically represented the largest investments in past plans. The goal was to get an early indication of the types of investments customers would value and their general willingness to pay for these investments, before Hydro One's planners started the investment planning process. Despite overall price concerns, customers indicated a preference for Hydro One to be a good steward of Ontario's electricity system, and that they are generally willing to pay more to invest in renewing aging infrastructure and improving reliability. While business customers are generally less willing to pay more to make these investments than residential customers, they still support investments in the electricity system and are willing to accept potential bill impacts The results of Phase 1 Customer Engagement are detailed in section 1.6 of the System Plans Framework (SPF)	Based on an assessment of customer needs and preferences identified through Phase 1 of the consultation process, Hydro One developed three options for a draft investment plan, including trade-offs between the options. 1) Option 1: slower pace 2) Option 2: draft plan 3) Option 3: accelerated plan These options were presented to customers during Phase 2 of the consultation process. Details on the options developed for the draft investment plan are included in **SPF Section 1.6**.
The COVID-19 pandemic started shortly after completion of Phase 1. Before proceeding to Phase 2, and to assess whether customer feedback received in Phase 1 was altered in any way by the pandemic, IRG carried out a "pulse check" survey among Hydro One's residential and small business customers in June-July 2020	The results of this pulse check survey were in line with the Phase I results	Hydro One continued to Phase 2 of its customer engagement process
Through Phase 2 of Customer Engagement process (in late summer and fall of 2020), transmission and distribution customers were invited to participate by completing an online workbook. Large Transmission customers and indirect customers served by other Distribution companies also had the opportunity to provide feedback on the draft Transmission plan. First Nation communities and the Métis Nation of Ontario were engaged through: · separate online workbooks · in-depth interviews Municipalities and key stakeholders were invited to provide feedback on the needs and outcome preference of their communities through one-on-one interviews	The Phase 2 results indicated that customers across all segments value the proposed investments in the electricity system and are supportive of Hydro One's draft investment plans. They are willing to accept bill or rate increases in exchange for prudent investments in the distribution and transmission systems. Some differences exist between customer segments regarding the specific level of investment, and corresponding bill impact, they prefer. Among the customer segments, residential and small business customers expressed the most support for investments that exceed spending levels included in the draft plan, even if those lead to larger increases on their monthly bill. Larger business customers, namely C&I and LDA customers, are evenly split in their preferred level of investment between the draft plan and a higher level of spending ("accelerated pace"). Large transmission (LTX) customers favour the draft plan over an accelerated pace. Across all segments, a significantly larger share of customers prefer an accelerated pace over a pace that is slower than the draft plan Specific needs and preferences are described in detail in SPF 1.6.	Specific actions taken to respond to customer needs and preferences identified in Phase 2 of the customer engagement are identified in the investment planning process sections found in SPF 1.7, TSP 2.7, DSP 3.7 and GSP 4.7
Hydro One maintains ongoing engagement and communication with Large Customers vis-a-vis 3 primary methods: 1) Acccount Executives hold regular meetings with Large Distribution Accounts (LDA) and Large Transmission Customers (LTX) 2) Ontario Grid Control Centre (OGCC) s Customer Operating Support Group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages 3) Outage Planning Group organizes bi-annual customer meetings throughout the province to coordinate outage planning activities	As discussed in **SPF Section 1.6,** customer feedback is solicited from Large Customers to ensure that: · the needs of customers are identified and discussed, and action plans are developed to address these needs	As discussed in **SPF Section 1.6**: If an action plan results in new or modified connection facilities and/or asset needs, the Account Executive (that's assigned to their Large Customer) will directly communicate with the affected customer(s) as it impacts connection process and contractual requirements. The outcomes of these discussions are used as inputs to the OGCC and Transmission System Outage process. Based on discussions with the OGCC's Customer Operating Support Group, Hydro One or the customer can complete required work to respond quickly to unexpected outages, and to coordinate switching activities. Based on discussions with the Outage Planning Group, customers may bring forward their own maintenance plans for their facilities, with a view to scheduling or bundling outages in a manner that minimizes the frequency and duration of outages for both the utility and the customer.
Hydro One established 7 oversight committees to hold meetings throughout the year to engage and obtain feedback from customers on select topics with a high level of customer interest: 1. Sarnia Area Reliability Oversight Committee 2. Toronto Hydro Oversight Committee 3. Bruce Power Oversight Committee 4. Metrolinx Oversight Committee 5. Hydro Ottawa Oversight Committee 6. Alectra Oversight Committee 7. OPG Oversight Committee	As discussed in **SPF Section 1.6**, the purpose of the oversight committees provide an early insight as to future investment needs more generally.	Through the ongoing feedback collected from customers during the year through the various oversight committees, Hydro One has incorporated the information more broadly for investment planning purposes. See Exhibit SPF **Section 1.6** for the details collected by Oversight Committee.
Through independent expert customer research firms, Hydro One collects feedback from all customer segments through: · transactional surveys (ongoing basis) · perception surveys (monthly for residential and small business customers; annually for C&I, LDA and LTX customers)	As discussed in **SPF Section 1.6**, **A)** Transactional surveys involve contacting a sub-set of Hydro One customers after they have had an interaction with the company to determine how well its customer service met their expectations. These surveys measure operational effectiveness for the call centre. **B)** Perception surveys monitor how well the company meets customers' expectations and delivers on critical success factors.	Based on the survey results, Hydro One uses this data to inform and improve business practices, and to stay informed about the trends that matter most to its distribution and transmission customers. See Exhibit SPF **Section 1.6** for the details on the Customer Satisfaction Research.
Hydro One's residential and small business customers work with the Customer Call Centre when they have a question about their service or bill. Customer feedback is received through: · phone, e-mail, chat, or mail Hydro One's C&I customers are serviced by the Business Contact Center.	Trends in customer needs are tracked and actively monitored by the respective call centres.	As discussed in Exhibit SPF Section 1.6, customer interactions through the Call Centre are monitored closely, and concerning trends are escalated and analyzed to assure Hydro One's performance is continuously improving and distribution system outcomes are aligned with customer needs and preferences.
Hydro One's External Relations department maintains relationships with representatives of the Ontario government, Members of Provincial Parliament, municipality representatives and elected officials, and key stakeholder groups that represent large customer segments for Hydro One. The External Relations department holds: · stakeholder and community events · public consultations		Through the public events and consultations, Hydro One is able to stay current with the issues that these key stakeholders and their constituents or members may have.
Hydro One engages its First Nations and Métis customers through ongoing engagement activities and through the Innovative Customer Engagement exercise described in SPF section 1.6.	See Exhibit A-07-02 for details.	See Exhibit A-07-02 for details.
Hydro One's Ombudsman Office performs systemic investigations and addresses specific customer issues.		As detailed in Exhibit SPF Section 1.6, Hydro One's Customer Service department works with the Ombudsman's office on a regular basis to understand any underlying trends of concern, which then informs Customer Service on how to better align how it works with its residential and commercial customers.

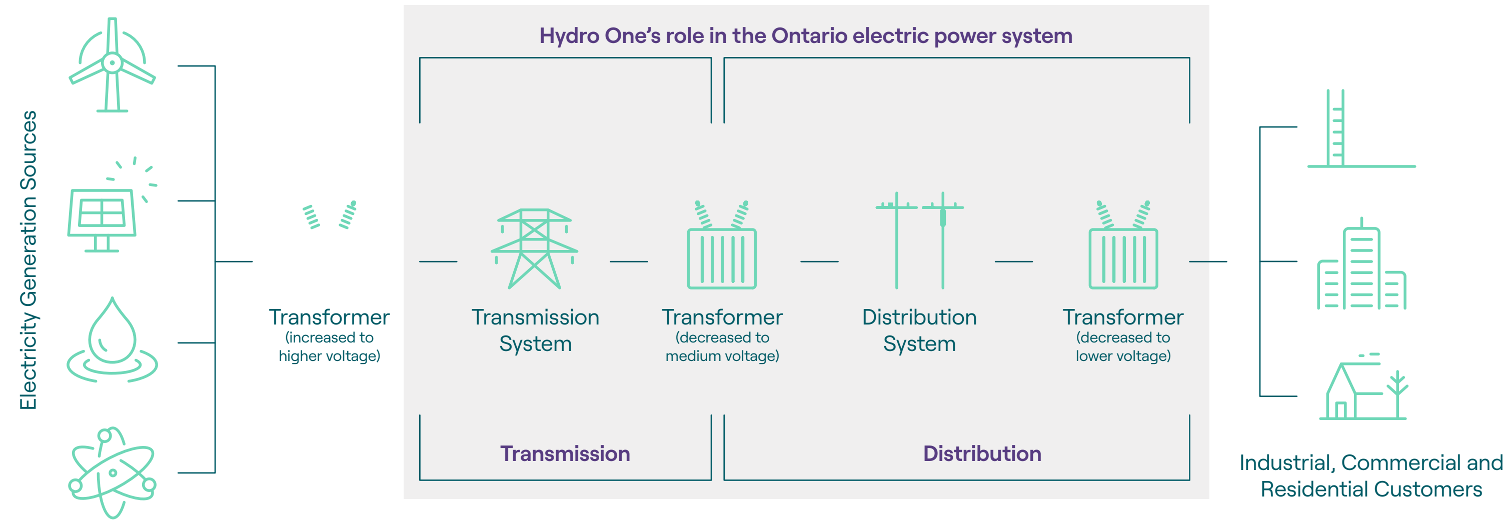
Note: Use "ALT-ENTER" to go to the next line within a cell

hydro one

Committed to a better & brighter Ontario

Our role in the system

Hydro One proudly serves 1.4 million customers, delivering and transmitting electricity to every corner of Ontario. We serve businesses, large and small and energize approximately 40 per cent of Canada's economy.



Distribution

1.6million
poles

1.4million
customers

That's about 1 pole per customer

Our service territory covers **75%** of Ontario

Transmission

We energize approximately **40%** of Canada's economy

The province's clean evergy mix means that **96%** of the electricity we deliver is clean

Attracting businesses to the province depends on a strong transmission system

For Hydro One's transmission and distribution service territories, please see TSP Section 2.1 and DSP Section 3.1, respectively.

Understanding our rate application

We are filing for our combined transmission and distribution rate application the five-year period from 2023 to 2027.

Our plan is developed through:

An evaluation of our current system and future system needs.

Understanding, through customer feedback, the current and future needs of our customers.

Balancing affordability with what the system needs and our customers' feedback.

Our proposed Investment Plan will renew or replace critical infrastructure, improve resiliency and reliability, prepare for the impacts of climate change, and support economic growth and customer choice.

Hydro One will seek approval from the Ontario Energy Board (OEB) to fund its plan. The OEB and consumer groups will review our plan through a public hearing process.

For more on Hydro One's Plan, see **HydroOne.com/5YearInvestmentPlan** Exhibit A-03-01 for Executive Summary and Business Plan

What customers told us

In almost every community equipment needs to be renewed, or replaced. To plan for the next five years, we engaged with almost 50,000 Ontarians who told us they wanted a more resilient electricity system that is ready for the future.

85% of customers want us to replace aging infrastructure when or before it starts to deteriorate

77% want us to make the investments necessary to keep businesses running safely and reliably

60% would support proactive investments to prepare the system for more severe weather

About **half** of customers wanted us to invest in infrastructure faster than our draft plan

Based on residential customers

For more on customer engagement process and results, see **HydroOne.com/5YearInvestmentPlan**, System Plan Framework, Section 1.6

What is needed?

The majority of our system was built in the **1950s** and **1960s**

Nearly **1** in **4** steel transmission towers are more than **80** years old

1 in every **20** wooden poles is now at risk of failure

4,000km of high voltage power lines need to be replaced

Our plan

Our five-year Investment Plan invests in a resilient electricity system to reduce the impacts of power outages for our customers by approximately 25%.

We will prepare our grid for the impacts of climate change and plan to invest in nearly every community we serve.

Our plan will result in:

For more on the investment plans, see the evidence in the Distribution System Plan, Transmission System Plan, Network System Plan, and General Plant System Plan at **HydroOne.com/ 5YearInvestmentPlan**

Renewing or replacing critical infrastructure

Transmission

Renew equipment on the high voltage transmission system, including

1,500km

of new high voltage power lines

Replace

129

transformers

Upgrade infrastructure at approximately

200

stations

Distribution

Upgrade equipment on the distribution system, including renewing or replacing approximately

65,000

wood poles

and

10%

of transformers

Improving resiliency and reliability, and preparing for impacts of climate change

Use automation and innovative solutions to reduce the impact of power outages for our distribution customers by approximately

25%

Install

1,000

smart devices per year to improve resiliency for customers who experience the most power outages

Prevent outages by removing dead and diseased trees that could strike power lines

Invest in taller and stronger poles to withstand more severe weather

Building a grid for the future to support economic growth and customer choice

Invest in new or upgraded infrastructure to accommodate community and industrial growth

Modernize meters and associated infrastructure to enable future flexibility, choice and cost savings

Install innovative energy battery and storage solutions to improve resiliency for those customers, including First Nations communities, by

60%

Connect close to

18,000

new distribution customers each year

Productivity & efficiency

Every dollar we invest comes at a cost to our customers and the people of Ontario, which is why we are committed to controlling costs and improving productivity.

From 2015 to 2020, Hydro One has achieved approximately
$738 million
of cumulative productivity savings.

We will target achieving
$750 million
in savings between 2023-2027.

Hydro One will seek approval of a revenue requirement in 2023

$1.8 billion for its transmission business

and

$1.6 billion for its distribution business

The revenue requirement, once approved for the first year, will escalate by a custom escalation factor over the next five years.

Bill impacts for Hydro One customers

Our plan will see a typical customer's bill increase by less than inflation.

Residential customers
A typical R1 (medium density) residential customer's **TOTAL** monthly bill will increase by an average of

$1.68

each year over the five-year period.

A typical R1 (medium density) residential customer's average monthly bill for **transmission** will increase by an average of **$0.39** each year over the five-year period

A typical R1 (medium density) residential customer's average monthly bill for **distribution** will increase by an average of **$1.29** each year over the five-year period

---

General service customers
A typical general service energy customer's (GSe<50kW) **TOTAL** monthly bill will increase by an average of

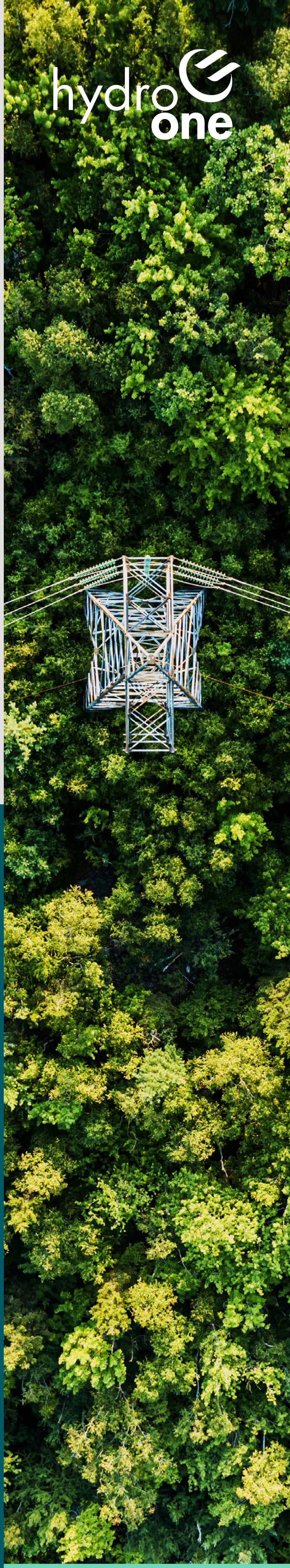
$3.75

each year over the five-year period.

A typical GSe< 50 kW customer's average monthly bill for **transmission** will increase by an average of **$0.83** each year over the five-year period

A typical GSe<50 kW customer's average monthly bill for **distribution** will increase by an average of **$2.92** each year over the five-year period

For more on bill impacts, see **HydroOne.com/5YearInvestmentPlan**, Exhibits H-10-01 and L-06-01.



Learn more about our plan at **HydroOne.com/ 5YearInvestmentPlan**

FIRST NATIONS AND MÉTIS ENGAGEMENT STRATEGY

1.0 OVERVIEW

This exhibit describes Hydro One's approach to Indigenous relations, Hydro One's engagement with Indigenous communities for the purposes of this Application, the needs and preferences that have been identified through those activities, and the steps Hydro One has taken to address them.

2.0 INDIGENOUS CUSTOMERS

Hydro One's Distribution business serves 89 First Nation communities in Ontario including 23,000 First Nation residential customers located on reserve lands. Hydro One Distribution also serves many Métis customers and engages with the Métis Nation of Ontario (MNO) which supports 31 Métis Chartered Community Councils across the province.

While Indigenous communities are not directly connected to Hydro One's transmission system, the Company's transmission assets are located on the reserve lands of 24 First Nation communities and within the traditional territories of all Indigenous communities.

Conversations with Indigenous communities are rapidly evolving. Indigenous communities' expectations are informed by their unique position as rights holders in Canada, the needs and aspirations of their individual communities, and by constitutional, legal and international rights including the United Nations Declaration on the Rights of Indigenous Peoples. It is imperative to Hydro One that that we contribute to implementation of the findings of the Truth and Reconciliation Commission of Canada, and in particular to Call to Action 92. Hydro One has chosen to embrace the evolving focus of its conversations with Indigenous communities and to evolve and improve our approaches to engagement and economic participation in Ontario. We are mapping a path to lead the industry by working with Indigenous communities to address their unique cultural, historic, commercial, legal and policy-related needs and preferences.

3.0 INDIGENOUS RELATIONS POLICY

Hydro One's Indigenous Relations Policy, updated in 2019, sets out the Company's commitment to building relationships with Indigenous people and communities. The policy delineates Hydro One's commitment to, among other things, increase procurement opportunities for Indigenous businesses, increase Indigenous representation in Hydro One's workforce, consult on projects that impact Aboriginal and Treaty rights, ensure Hydro One employees have the training to advance relationships and understanding with Indigenous communities, and advance positive and lasting socio-economic outcomes with Indigenous communities.

4.0 CUSTOMER ENGAGEMENT

To identify customer needs and preferences in preparation for its 2023 – 2027 investment planning process and this Application, Hydro One engaged Innovative Research Group (IRG) to develop and conduct a customer engagement study (the IRG Study). Hydro One and IRG employed a two-phased approach, engaging customers at the beginning of the investment planning process, and again after draft investment plans were prepared. The customer engagement process is described in SPF Section 1.6.

All customers were invited to complete an online workbook in Phases 1 and 2 of the IRG Study. On-reserve First Nation customers received a separate workbook to reflect the First Nations Delivery Credit. In addition, First Nation Chiefs or delegates had the opportunity to participate in the investment planning process and share their communities' specific needs and preferences. Hydro One reached out to the Métis Nation of Ontario (MNO), whose views were considered throughout the engagement. In addition to collecting feedback from individual customers, MNO representatives were invited to discuss the needs and outcome preference of their communities. The results of the various forms of engagement are detailed below.

4.1 PHASE 1 CUSTOMER ENGAGEMENT PROCESS AND RESULTS

In Phase 1 of the customer engagement process, the needs and outcome preferences of on-reserve First Nation customers, and their feedback on high-level investment trade-offs, largely aligned with the results from other customer segments. First Nation customers are generally willing to pay more to invest in renewing aging infrastructure and improving reliability.[1] While First Nation customers are slightly less willing to pay more to make these investments than residential customers, they still support investments in the electricity system and are willing to accept potential bill impacts.[2] Detailed results of the Phase 1 engagement are described in SPF Section 1.6.2.3.

In addition to the workbooks, Phase 1 engagement sessions were held with the participation of Hydro One's senior management with the MNO on October 19, 2019 and with First Nation representatives on November 5, 2019. First Nation representatives expressed interest in: affordability, reliability and outage response, business development opportunities, system access, and accountability. MNO representatives expressed interest in: reliability, affordability, outage communications, procurement, employment and training and partnerships.

Throughout the spring and summer of 2020, the system planners reviewed the Phase 1 feedback and incorporated it into the development of three draft investment scenarios for each of Transmission and Distribution, which were then presented to customers as part of Phase 2 of the customer engagement, as further described below.

---

[1] IRG Report p. 29
[2] IRG Report p.5

expressed support for Hydro One's proposed draft investment plan but expressed concern over the potential cost impacts. They expressed interest in improved communications with Hydro One, procurement opportunities, and in some cases, treaty acknowledgement and reconciliation.[8]

Hydro One's planners used the Phase 2 feedback to finalize the investment plans. This approach allowed Hydro One to ensure the final plans for 2023-27 are responsive to customer needs and preferences. Section 1.7 of the NSP further describes the integrated nature of the customer engagement process and the investment planning process and how customer feedback was taken into account in Hydro One's investment planning process.

5.0 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:

Table 1 - Needs and Preferences of Indigenous Communities

Common Issues		Actions Taken to Address Issues
Reliability	Frequent or lengthy outages impacting electricity supply to on reserve homes and businesses.	In general, the System Plans will deliver improved reliability to our customers, pursuing safe, cost effective solutions to meet their needs, including deployment of over 1,000 smart devices/year and batteries to support ~800 customers/year. Distribution reliability to First Nation communities is addressed in Attachment 1 to this exhibit: "First Nations Reliability Report". Transmission reliability to First Nation communities is addressed in TSP Section 2.4 Attachment 1. The key points in these reports are described below. Over the 2023-2027 period, Hydro One's Indigenous Relations Group will work with the Transmission and Distribution businesses to develop and implement a First Nations Electricity Reliability Improvement Plan.

[8] SPF Section 1.6, Attachment 3 – Métis Nation of Ontario Engagement Report

System Access	First Nation community growth plans require more capacity and new connections	The DSP will provide customers timely access to the network through customer connections and paced regional expansions. Hydro One will enable connections (approximately 18,000 annually) of new load customers including First Nation customers and communities, and to upgrade supply capacity (approximately 4,500 annually) of existing load customers including First Nation customers and communities, to the distribution system. Further detail is included in DSP Section 3.1 and D-SA-02.
Procurement Opportunities	Indigenous representatives expressed interest in procurement opportunities	Hydro One's Indigenous Procurement Policy has steadily increased procurement opportunities for qualified Indigenous businesses from 1.62% ($24.1M) in 2017 to 2.46% ($42.0M) of sourceable spend in 2020. Procurement targets will be set for each year of the application period, and Hydro One's Indigenous Relations Group will work with Supply Chain to set clear expectations with external vendors to support increased Indigenous procurement. In 2021 Hydro One set a new target of 5% of sourceable spend for procurement opportunities for qualified Indigenous businesses by 2026. Six Indigenous Procurement Workshops were held in 2020 notwithstanding the pandemic. Meetings are continuing to be held in 2021 between Hydro One and major suppliers to communicate the expectation that the procurement target is reached. Hydro One has continued to refine its contract process for Indigenous businesses. Procurement opportunities are described in further detail in section 6 below.
Partnerships and Business Opportunities	Indigenous communities expressed interest in more ownership opportunities and other business partnerships.	Hydro One owns and operates two transmission lines in partnership with Indigenous communities, through B2M LP and NRLP. Hydro One anticipates having one or more Indigenous equity partners for new major transmission line projects that cross traditional, treaty or reserve lands, and that once a project is at or near in-servicing, the assets may be transferred to a newly licensed partnership. Hydro One has submitted an application to the OEB to establish a Deferral Account for these projects (EB-2021-0169) on this basis.

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 with the Crown to address access rights in a fair and timely manner, including historic rights that need renewal. Hydro One's Indigenous Relations Group and Distribution Lines and Forestry are working together and have developed a communication protocols between the Company and the Indigenous communities it serves. The Indigenous Relations department at Hydro One is leading these efforts in close consultation with Indigenous communities, the Real Estate, Legal and Regulatory Affairs departments to resolve these outstanding matters. Further details are included in Exhibit E-09-04 – Taxes Other than Income Taxes
Employment	Indigenous communities expressed interest in more employment opportunities	Hydro One's Indigenous Relations Group is identifying and address barriers to Indigenous employment and retention in 2021 and will implement recommendations from 2021 to 2027.
Communications	Indigenous communities expressed interest in better communication	Hydro One's Indigenous Relations Group is reviewing the Indigenous Relations Policy and implementing standardized engagement tools, templates and processes in 2021 to ensure consistency and transparency, over the 2023-2027 period. Hydro One will focus on relationship building and improved communication over the 2023-2027 period
Affordability	MNO representatives expressed concern over cost impacts of the plans and First Nation communities expressed interest in having the First Nation Delivery Credit (FNDC) applied to Band buildings and on-reserve businesses.	On a combined Transmission and Distribution basis, the estimated total monthly bill impact for a typical Hydro One residential customer is an average annual increase of 1.1% ($1.68) over the 2023-2027 period, which is less than the rate of inflation and less than the bill impacts associated with the high-level trade offs selected by customers in the Phase 2 workbook. Hydro One does not have authority to apply the FNDC beyond what is specified in the legislation.

6.0 RELIABILITY

As described above, First Nation customers surveyed as part of the workbook prioritized reliability outcomes and supported investments that would improve reliability. First Nation Chiefs and their representatives, particularly those from Northern and more remote communities, focussed on the impacts of poor reliability on their communities. In general, interviews with First Nation communities identified reliability and power quality as a priority. MNO representatives also identified reliability as a priority.

In the Prior Distribution Decision, the OEB directed Hydro One to explicitly identify initiatives to address reliability challenges in northern and First Nation communities, including economically justified Distributed Energy Resource (DER) solutions.

Two First Nation reliability reports are included in this Application. Distribution reliability to First Nation communities is addressed in Attachment 1 to this exhibit: "First Nations Reliability Report". Transmission reliability to First Nation communities is addressed in TSP Section 2.4 Attachment 1. These include a description of reliability to First Nation communities and a summary of the actions that Hydro One is planning over the 2023-2027 period to improve reliability for First Nation communities. The key points in these reports are described below.

All 89 First Nation communities served by Hydro One are connected to the Hydro One distribution system. The distribution lines servicing First Nation communities are supplied from 69 transmission lines, four direct connections to high voltage stations busses and 71 delivery points as of the end of 2020. On average, Hydro One customers residing within First Nation communities experienced nearly 26 hours of interruption and over seven sustained interruptions per year. The support from northern First Nation towards reliability-focused investments aligns with reliability data indicating that northern First Nation communities statistically experience the poorest reliability amongst all First Nation communities serviced by Hydro One.

The majority of delivery points in the Northern sub-system are served by single circuit 115 kV lines that travel long distances through heavily treed areas. Broken branches or uprooted trees are easily blown into the line causing an outage, and long distances, rugged terrain and extreme weather conditions, mean that repairs for forced outages on the Northern system tend to take longer to accomplish.

Hydro One's TSP includes a number of investments to address reliability issues in northern First Nation communities. In particular, there are seven delivery points that are outliers for both duration and frequency of outages in the Northern transmission sub-system. These delivery points are served by three 115kV circuits, each of which will be refurbished before or during the 2023-2027 period. In addition, Hydro One is refurbishing two single circuits, two double circuits and two stations servicing First Nation communities over the 2023-2027 period. See TSP Section 2.4, Attachment 1 for details.

Hydro One's DSP also includes a number of investments to address reliability issues in northern communities including energy storage solutions, investments to address feeders with the largest SAIDI contribution, and vegetation management investments. See Attachment 1 to this exhibit for details.

7.0 PROCUREMENT OPPORTUNITIES

Hydro One supports the Indigenous Relations Policy through its procurement opportunities for qualified Indigenous businesses. This is intended to develop and expand the number and capacity of Indigenous suppliers who can provide goods and services to Hydro One. Hydro One procures materials and services through a framework of policies and procedures that are intended to deliver productivity and allow the company to achieve greater value in its sourcing. Hydro One has introduced a number of measures to help increase access to procurement opportunities for Indigenous businesses, Indigenous communities will access meaningful benefits from Hydro One's activities, and new relationships will be established and strengthened. These measures include:

- Hydro One's Indigenous Procurement Procedure (IPP) is designed to increase opportunities for Indigenous businesses to supply Hydro One with services and materials through a variety of sourcing processes such as competitive bids and direct awards.[9]
- Hydro One has implemented criteria related to Indigenous participation requirements included in all Requests for Proposal (RFP) documents regarding the use of an Indigenous business sub-contractor(s) to complete the goods and services requirements, local Indigenous participation commitment, and active Indigenous diversity programs, policies and/or initiatives.
- In November 2018, Hydro One implemented a Supplier Code of Conduct that supports our efforts to be a supply chain leader that protects people, manages impacts on the environment, respects Indigenous relationships and promotes energy efficiency. The Supplier Code of Conduct sets out Hydro One's expectations for its Suppliers to conduct business with the same ethical standards that Hydro One maintains. Furthermore, Hydro One gives preference to suppliers that are Indigenous or have implemented, or are implementing, a formal Indigenous Strategy and plans that are committed to Indigenous sub-contracting and employment.
- In 2020, 51 contracts were awarded to Indigenous businesses.
- Hydro One hosts Indigenous workshops to share information about Hydro One's procurement process, learn about products and services local Indigenous communities and businesses can provide and share upcoming procurement opportunities with both of them. In 2020, six virtual workshops were held.
- Hydro One organized its first Annual Provincial Indigenous Business Fair on September 25, 2019 in Toronto. The event showcased over 40 Indigenous businesses from across the

---

[9] Hydro One applies several approaches to provide opportunities to Indigenous businesses: (i) Indigenous participation is preferred – every Request for Proposal contains Indigenous Participation language; (ii) Indigenous participation is mandatory; (iii) Competition is limited specifically to qualified Indigenous businesses; (iv) Direct award to qualified Indigenous business

province, and offered them the opportunity to meet and network with representatives from Hydro One and our industry partners.

- In 2020, Hydro One achieved PAR Silver Re-Certification, which required demonstration of meeting goals set out in the 2017 application, of which a focal point was the creation and achievement of Indigenous procurement spend targets. These targets measure Hydro One's year over year spend growth with Indigenous communities and businesses.
- In 2021, Hydro One continues to host virtual procurement workshops. This year, Hydro One established a new target of 5% of sourceable spend for Indigenous Procurement by 2026.

Indigenous businesses currently supply a diverse and growing range of materials and services to Hydro One. Examples include: brush clearing, winter road construction, archaeological services, general contracting, and printing supplies. Due to Hydro One's ongoing efforts, its annual Indigenous procurement has increased from $16.5M (1.62%) in 2016 to $42M (2.46%) of sourceable spend in 2020.

8.0 PROGRESSIVE INDIGENOUS RELATIONS CERTIFICATION

One of Hydro One's priorities is to advance reconciliation and work proactively to build relationships with Indigenous people and communities based on understanding, respect and mutual trust. A key way that Hydro One plans on achieving this is through its ongoing participation and re-certification in the Canadian Council for Indigenous Business (CCAB) Progressive Indigenous Relations (PAR) program. In 2020, Hydro One was recertified by the CCAB under its Progressive Aboriginal Relations (PAR) program achieving a Silver Level Certification. This is a level above Hydro One's 2017 PAR Bronze Level Certification. Over the 2023-2027 period, Hydro One aims to reach Gold Level Certification.

9.0 CONCLUSION

Hydro One is continuing to gain a better appreciation of the aspirations, goals, interests and needs of First Nation and Métis communities and individuals as rights holders, partners, landlords, customers and employees. Feedback received from First Nation and Métis communities and customers has resulted in Hydro One introducing measures intended to help address a number of the concerns raised. Hydro One recognizes that more work needs to be done. Hydro One will continue to engage and work with First Nations and Métis communities as it develops and executes programs intended to provide better service and customer care and works to build and maintain positive relationships with First Nations and Métis communities across Ontario.

This page left blank intentionally.

First Nations Reliability Report 2021

Table of Contents

1. Purpose

In the OEB's March 7, 2019 Decision and Order, Hydro One was directed to explicitly identify initiatives to address reliability challenges in northern communities, including economically justified Distributed Energy Resource (DER) solutions. Hydro One has several initiatives that are focused on improving reliability, which will also address reliability issues in northern communities. These initiatives are:

- DSP Section 3.11, D-SS-04 Energy Storage Solutions: Targeting reliability with residential household storage solution for individual customers and grid scale storage solution for communities
- DSP Section 3.11, D-SS-05 Worst Performing Feeders: Targeting feeders with the largest SAIDI contribution
- Exhibit E-03-02, subsection 2.4 Vegetation Management: Vegetation management that will improve reliability for all customers

Details of each initiative can be found in the respective ISD or evidence section.

Most First Nations communities are located in Northern Ontario, north of Sudbury, and thus a particular focus was paid to these communities in consideration of the OEB's directive. This report summarizes Hydro One's analysis of feeders that supply First Nations communities and identifies opportunities to improve reliability, including economically justified DER (excluding communities served by Hydro One Remote Communities Inc.). Hydro One also received feedback through a First Nations customer engagement exercise conducted by Innovative Research Group (Innovative).[1] The results of this engagement informed the proposed reliability initiatives summarized in section 4 of this study.

2. Nature of First Nations Supply

First Nations communities are often located at the end of rural distribution feeders that are typically longer than an average feeder. As a result, these lengthy feeders have increased exposure and are vulnerable to interruptions. In addition, most First Nations communities are supplied by radial feeders, potentially increasing the duration of outages as there are no alternate supply sources. The

[1] First Nations Engagement Report by IRG, SPF Section 1.6, Attachment

following analysis will detail the methods used to develop the proposed reliability initiatives that addresses these reliability challenges.

3. Data Sources

Two data sources were used to inform the analysis of First Nations communities' reliability performance: First Nations engagement and community reliability metrics.

3.1. First Nations Engagement

Hydro One serves 88 First Nation communities representing close to 23,000 distribution system customers. Innovative reached out to all communities and was able to set up meetings with 24 First Nations Chiefs and/or their representatives. Through these meetings Hydro One was able to collect feedback on Hydro One's 2023-2027 draft investment plan. This engagement exercise built upon a previous engagement conducted in 2019 to collect input from First Nations Chiefs and/or their representatives on their electricity needs and general preferences. Both engagements were conducted to inform Hydro One's 2023-2027 investment plan.

The results of the engagement exercise showed that First Nations are generally supportive of the four following objectives:[2]

1. Preserve the electricity system for future generations,
2. Improve system reliability and safety,
3. Help customers with poor reliability, and
4. Enable community growth.

Among First Nations participants, those representatives from northern communities were especially supportive of reliability-focused investments.[2] The support from northern First Nations towards reliability-focused investments aligns with the reliability data shown in the report below, since northern First Nations communities statistically experience the poorest reliability amongst all First Nations communities serviced by Hydro One.

Northern First Nations communities made it clear that poor reliability is not merely an inconvenience; it poses a community health and safety issue, particularly during the COVID-19 pandemic. For example, during power outages, communities are typically able to gather in centralized locations for

[2] Ibid

support and warmth. These gatherings posed a health risk during the pandemic, making reliable power delivery more critical than ever. Many northern communities expressed openness to the idea of non-traditional solutions such as battery storage solutions.[3]

3.2. Community Reliability Data

This report examines the average annual interruption duration, frequency, and cause, from 2018 to 2020, for each First Nations community supplied by Hydro One Distribution. This information underpins the mitigating actions that can be used to improve reliability. Figure 1 below shows the breakdown of outage causes for all First Nations communities.

As seen in Figure 1, the leading causes of service interruption are tree contacts and defective equipment. It should be noted that even if traditional investments are made to address these vegetation and equipment issues, it is still possible for a community to experience poor reliability. For example, in a case where the distribution line serving a community is long, and traverses heavily forested off-road areas, vegetation management can reduce amount of tree contact outages. However, restoration time may still be longer than average should an outage occur. In these cases - where traditional solutions, including vegetation management and fault indicators, are not expected to sufficiently improve reliability - battery storage is considered as an option as it can mitigate the impact of all upstream outages regardless of cause.

[3] Ibid.

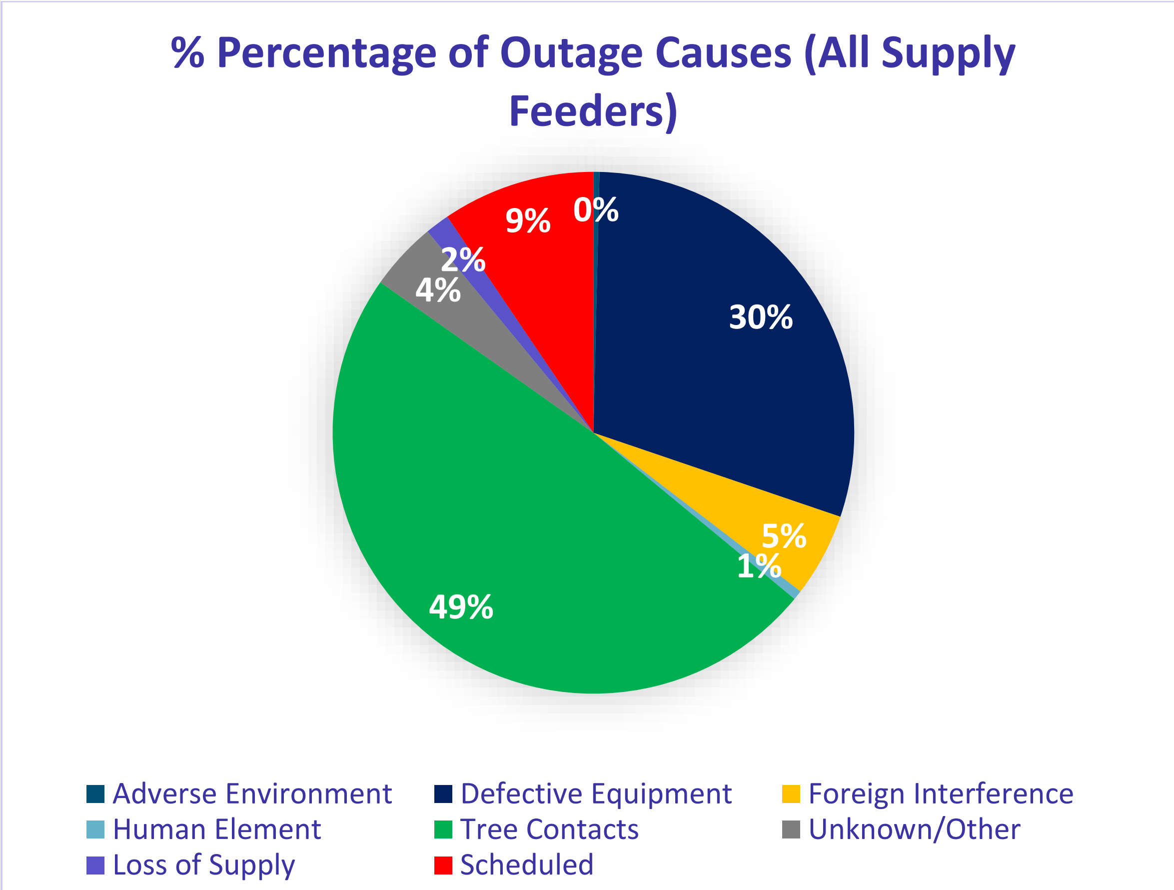


Figure 1*: *Historical Outage Data of All First Nations communities' feeders 2018-2020

On average, Hydro One customers residing within First Nations communities experienced nearly 26 hours of interruption and over seven sustained interruptions per year. The Figure 2 below provides a distribution of annual average outage duration for all First Nations communities over the 2018-2020 period, along with the associated annual number of interruptions. A complete list of reliability data for all communities can be found in Appendix A of this report.

support and warmth. These gatherings posed a health risk during the pandemic, making reliable power delivery more critical than ever. Many northern communities expressed openness to the idea of non-traditional solutions such as battery storage solutions.[3]

3.2. Community Reliability Data

This report examines the average annual interruption duration, frequency, and cause, from 2018 to 2020, for each First Nations community supplied by Hydro One Distribution. This information underpins the mitigating actions that can be used to improve reliability. Figure 1 below shows the breakdown of outage causes for all First Nations communities.

As seen in Figure 1, the leading causes of service interruption are tree contacts and defective equipment. It should be noted that even if traditional investments are made to address these vegetation and equipment issues, it is still possible for a community to experience poor reliability. For example, in a case where the distribution line serving a community is long, and traverses heavily forested off-road areas, vegetation management can reduce amount of tree contact outages. However, restoration time may still be longer than average should an outage occur. In these cases - where traditional solutions, including vegetation management and fault indicators, are not expected to sufficiently improve reliability - battery storage is considered as an option as it can mitigate the impact of all upstream outages regardless of cause.

[3] Ibid.

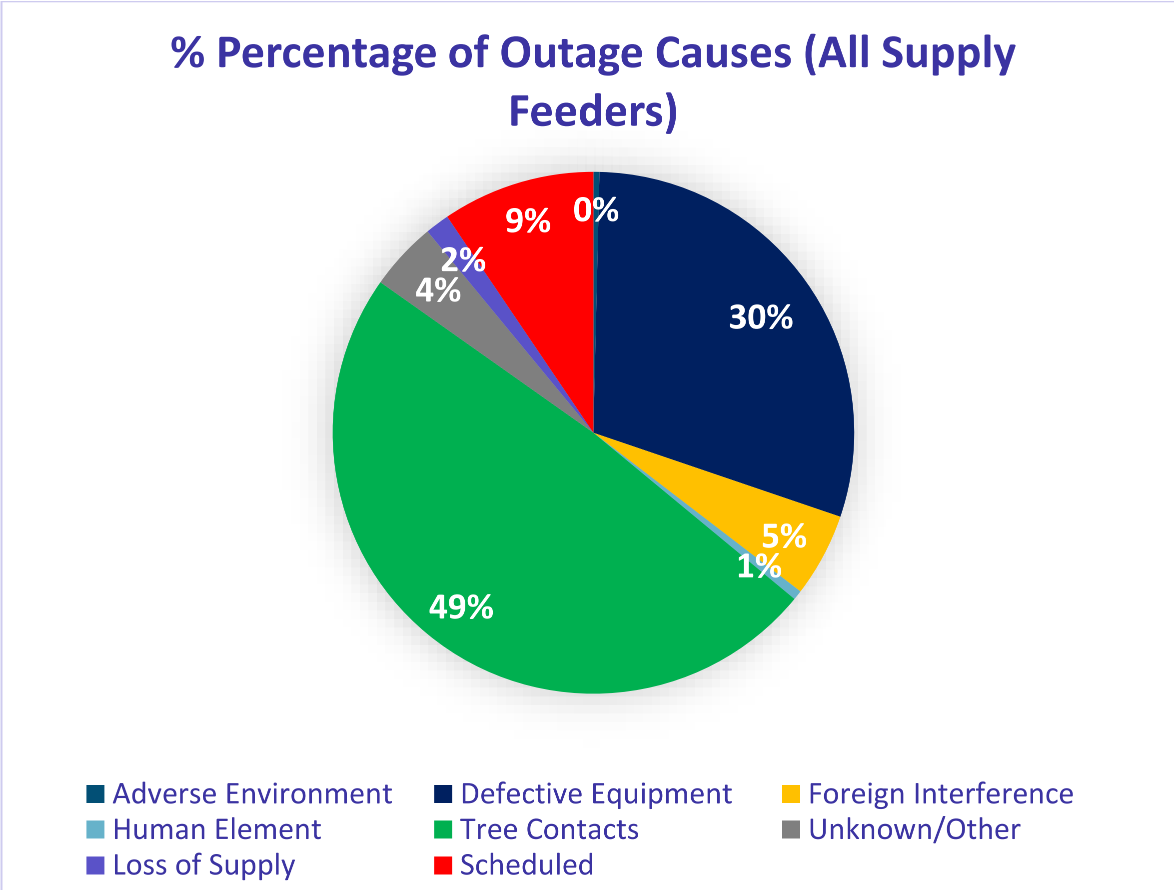


***Figure 1*: Historical Outage Data of All First Nations communities' feeders 2018-2020**

On average, Hydro One customers residing within First Nations communities experienced nearly 26 hours of interruption and over seven sustained interruptions per year. The Figure 2 below provides a distribution of annual average outage duration for all First Nations communities over the 2018-2020 period, along with the associated annual number of interruptions. A complete list of reliability data for all communities can be found in Appendix A of this report.

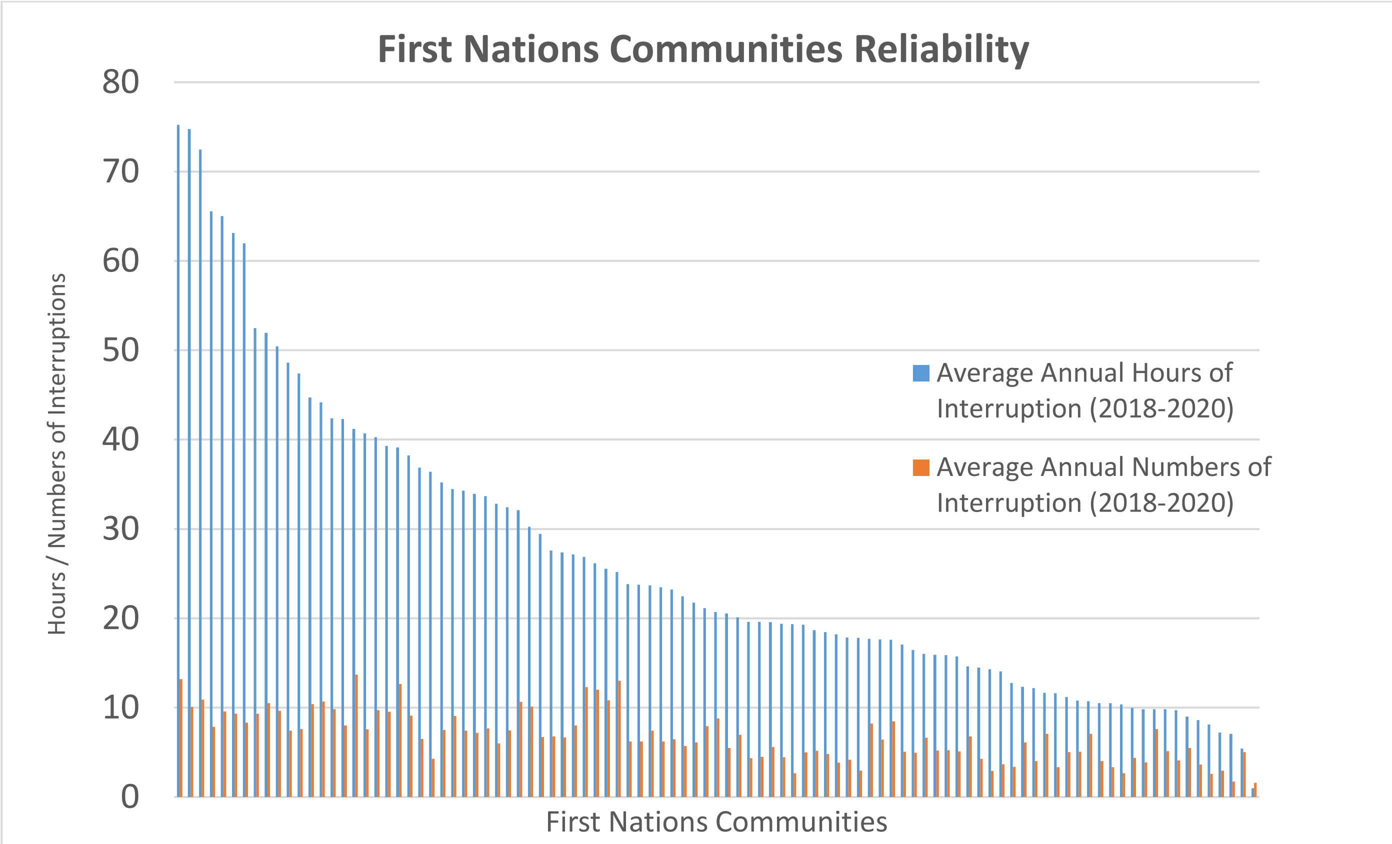


Figure 2: First Nations Communities Sorted by Annual Average Outage Duration for 2018-2020

4. Reliability Improvement Initiatives for First Nations Communities

Feeder performance data was used to rank First Nations communities by total annual outage duration over the 2018-2020 period. The primary causes contributing to annual outage duration were determined and used to estimate the effectiveness of Hydro One's reliability improvement initiatives.

Reliability will be improved for First Nations communities through vegetation management, installation of remote controllable switches and Communicating Faulted Circuit Indicators (CFCI), and where justified, investments in battery energy storage systems to provide back-up power.

4.1. Vegetation Management

Hydro One has adopted an Optimal Cycle Protocol (OCP) to manage vegetation along supply feeders. As shown in Figure 1 above, tree contacts are the primary cause of outages for First Nations communities. For all First Nations communities, vegetation management on the supply feeder will be performed in accordance with Hydro One's Optimal Cycle Protocol. See section E-03-02, subsection 2.4 for more details on OCP.

4.2. Remote Controllable Switches and Fault Location

For some First Nations communities, the installation of remote controllable switches and fault location will improve reliability. Hydro One is deploying remotely controlled sectionalization devices that will limit the duration and impact of faults on the system. Hydro One is also installing fault location sensors to facilitate faster mobilization of crews to the source of the issue and enable quicker restoration of power. See DSP Section 3.11, D-SS-05 Worst Performing Feeders for more details on this initiative.

4.3. Battery Energy Storage

For some First Nations communities, battery energy storage may be the most cost effective method to improve reliability if other alternatives prove inadequate or are not economically viable. This section describes how battery energy storage is evaluated and determined to be a candidate to improve reliability for First Nations communities.

Battery energy storage systems are a form of DER that can be used as a temporary source of energy during a system outage. In the context of this report, battery storage will be designed to pick up load on an islanded feeder section when there is an interruption to the normal source of supply.

Using the historical outage data and community energy needs as key inputs, an assessment of each community was performed to study the effectiveness of a battery energy storage system to improve reliability. The anticipated reliability improvements that resulted from this assessment were then used to quantify the reliability risks mitigated, in alignment with Hydro One's investment planning process detailed in SPF Section 1.7.

Two sizing criteria are used to determine the appropriate battery size needed to improve reliability for the First Nations. The first criterion, peak battery output (kW), takes into account the estimated peak demand of the community. Peak demand is based on historical community load, while also taking into account future load growth. The second criterion, total battery energy (kWh), takes into account the average energy lost during an outage. Total battery energy is estimated based on average outage duration and average energy needs of the community.

The list below identifies First Nations Communities that are potential candidates for battery energy storage systems. The expected reliability risk mitigated at these communities supports that the investment needed for the installation of battery energy storage systems is a cost effective method to improve reliability. These First Nation Communities have seen frequent outages and experienced long outage duration in 2018-2020.

The following are the First Nation communities that are candidates for energy storage:

- Anishinaabeg of Naongashiing
- Atikameksheng Anishnawbek
- Brunswick House First Nation
- Chapleau Cree First Nation
- Chapleau Ojibway First Nation
- Dokis First Nation
- Henvey Inlet First Nation
- Lac La Croix First Nation
- Magnetawan First Nation
- Mattagami First Nation
- Mishkeegogamang First Nation
- Moose Deer Point
- Naicatchewenin First Nation
- Netmizaaggamig Nishnaabeg
- Ojibway Nation of the Saugeen
- Ojibways of the Pic River First Nation
- Shawanaga First Nation
- Sheshegwaning First Nation
- Shoal Lake #40 First Nation
- Temagami First Nation
- Wahgoshig First Nation
- Wahta Mohawk First Nation
- Wasauksing First Nation
- Zhiibaahaasing First Nation

To proceed with battery storage, the candidate communities are subject to detailed studies to ensure that specific conditions are met. The conditions outlined below are critical requirements for a successful battery storage installation.

1. Support from the local First Nation to pursue energy storage on nearby lands
2. Availability of land for purchase, within proximity of the community to maximize benefit
3. Proposed site free of archaeological and environmental risks or concerns
4. Adequate internet connectivity and speed to enable battery storage system monitoring
5. system configuration to accommodate energy storage

5. Conclusion

Each of the energy storage candidates listed above will be studied in detail to determine the conditions of each potential installation including: the level of support from the First Nation community; site availability and characteristics; adequate internet connectivity; and other distribution system upgrades needed to support the installation. The detailed study results will be used to confirm the feasibility of installing an energy storage system for the community and determine the prioritization of the installation. The funding plan and expected improvement in reliability for the prioritized list of energy storage system installations is outlined in DSP Section 3.11, D-SS-04 Energy Storage Solutions.

Appendix A: Reliability Data by First Nations Community

First Nations Community	Average Annual Hours of Interruption (2018-20)	Average Annual Number of Interruptions (2018-20)
Abitibi 70	29	7
Agency 1	11	3
Alderville First Nation	44	8
Aroland First Nation	44	10
Bear Island 1	42	10
Big Grassy River 35G	18	8
Big Island Mainland 93	18	8
Chapleau 74A	52	9
Chapleau Cree Fox Lake	47	8
Chief's Point 28	16	5
Chippewas of Georgina Island First Nation	10	3
Chippewas of the Thames First Nation 42	18	4
Christian Island 30	19	5
Christian Island 30A	20	5
Constance Lake 92	25	13
Couchiching 16A	8	3
Curve Lake First Nation 35	35	7
Dokis 9	75	13
Duck Lake 76B	49	7
Eagle Lake 27	1	2
Factory Island 1	9	3
French River 13	20	4
Ginoogaming First Nation	23	6
Grassy Narrows	20	7
Gull River 55	21	8
Henvey Inlet 2	72	11
Hiawatha First Nation 36	22	6
Islands in the Trent Waters 36A	42	8
Kenora 38B	5	5
Kettle Point 44	16	7
Lac Seul 28	16	5
Lake Helen 53A	16	5

First Nations Community	Average Annual Hours of Interruption (2018-20)	Average Annual Number of Interruptions (2018-20)
Long Lake 58	24	6
Magnetawan 1	65	10
Manitou Rapids 11	9	5
Matachewan 72	27	8
Mattagami 71	75	10
M'chigeeng 22	24	6
Mississagi River 8	10	4
Mississauga's of Scugog Island	13	3
Mnjikaning First Nation 32	18	3
Moose Point 79	66	8
Moravian 47	18	5
Munsee-Delaware Nation 1	19	5
Naiscoutaing 17A	63	9
Neguaguon Lake 25D	41	14
New Credit 40A	11	4
New Post 69A	7	2
Neyaashiinigmiing	16	5
Nipissing 10	7	3
Ojibway Nation of Saugeen	44	11
Oneida 41	18	4
Osnaburgh 63A	34	8
Osnaburgh 63B	34	7
Parry Island First Nation	34	7
Pays Plat 51	28	7
Pic Mobert Reserve North	50	10
Pic Mobert Reserve South	52	10
Pic River 50	30	10
Pikwakanagan	21	9
Rainy Lake 17A	32	11
Rainy Lake 17B	39	13
Rainy Lake 18C	14	4
Rainy Lake 26A	20	6
Rat Portage 38A	11	5
Rocky Bay 1	27	7

First Nations Community	Average Annual Hours of Interruption (2018-20)	Average Annual Number of Interruptions (2018-20)
Sabaskong Bay 35D	12	6
Sagamok	23	6
Saug-A-Gaw-Sing 1	26	11
Saugeen 29	10	5
Seine River 23A	27	12
Serpent River 7	17	5
Shawanaga 17	36	4
Shawanaga 17B	62	8
Sheguiandah 24	21	6
Sheshegwaning 20	40	10
Shoal Lake 34B2	34	9
Shoal Lake 39A	24	7
Shoal Lake 40	38	9
Six Nations 40	19	4
Sturgeon Falls 23	26	12
Sucker Creek 23	12	4
The Dalles 38C	10	4
Thessalon 12	10	4
Tyendinaga Mohawk Territory	9	4
Wabaseemoong 29	14	3
Wabauskang 21	15	7
Wabigoon Lake 27	18	6
Wahnapitei 11	19	3
Wahta Mohawk Territory	33	6
Walpole Island 46	12	3
Whitefish Bay 32A	11	7
Whitefish Bay 33A	10	8
Whitefish Bay 34A	12	7
Whitefish Lake 6	37	7
Whitefish River 4	14	4
Wikwemikong Unceded 26	22	6
Zhiibaahaasing 19A	39	10

ACQUIRED DISTRIBUTION AND TRANSMISSION UTILITIES

1.1 NORFOLK POWER DISTRIBUTION INC., HALDIMAND COUNTY HYDRO INC., AND WOODSTOCK HYDRO SERVICES INC.

In 2014 and 2015, Hydro One Inc. acquired Norfolk Power Distribution Inc. (NPDI) (EB-2013-0196/0187/0198), Haldimand County Hydro Inc. (HCHI) (EB-2014-0244) and Woodstock Hydro Services Inc. (WHSI) (EB-2014-0213) (collectively, the Acquired Utilities).[1] The distribution system of each of the Acquired Utilities was transferred to Hydro One in the year following each acquisition.[2]

In this Application, Hydro One proposes to integrate the Acquired Utilities for rate making purposes.

In Exhibit L-01-02, Hydro One describes its proposal to place customers formerly served by the Acquired Utilities into new rate classes. Exhibit L-01-03 describes Hydro One's proposed cost allocation approach to appropriately reflect the costs of serving these acquired customers. In Exhibit L-02-01, Hydro One discusses its proposed approach for setting the rates for these acquired customers under the new rate structure. Finally, L-03-01 describes the benefits of Hydro One's proposal to integrate the customers of the Acquired Utilities into Hydro One's distribution rate structure. The benefits to both the customers of the Acquired Utilities and Hydro One's legacy customers are discussed. L-03-01 also details the savings achieved as a result of consolidation.

As detailed in Exhibit L-03-01, the results from the cost allocation and rate design process show that $32.8M is proposed to be collected from customers of the Acquired Utilities in 2023, which

[1] NDPI was acquired on August 29, 2014; HCHI on June 30, 2015; and WHSI on October 31, 2015.
[2] The transfer of the former NDPI distribution system took place on September 1, 2015; the transfer of the former HCHI and WHSI distribution system took place on September 1, 2016.

is less than the $42.2M that would have otherwise have been collected from them in 2023 in the absence of the transactions, representing a benefit to those customers of $9.4M or a 22% reduction in the total revenue requirement that would otherwise have been collected from them. Moreover, the $32.8M to be collected from customers of the Acquired Utilities in 2023 is greater than the $30.9M in Hydro One's incremental revenue requirement associated with serving those customers. This represents a benefit to Hydro One's legacy customers as it results in a $1.9M reduction in the revenue that would otherwise have been collected from Hydro One's legacy customers in the absence of the transactions. This demonstrates that the acquisitions resulted in a benefit for both legacy and the Acquired Utilities' customers.

All three of the Acquired Utilities have been integrated into Hydro One operations and planning. However, the Acquired Utilities have been excluded from capital expenditures and in-service additions until January 1, 2023, the date they will be integrated into Hydro One for rate-making purposes. Distribution System Plan (DSP) Section 3.9, Attachment 3 provides information related to capital expenditures that are unique to the Acquired Utilities until December 31, 2022 as well as historical fixed asset and rate base information.

As confirmed in EB-2017-0049, the premium on these acquisitions was paid by Hydro One's shareholder, and has not and will not be recovered from customers.[3] Moreover, there were no incentives beyond the purchase price to encourage a shareholder to agree to the consolidation.

[3] Further discussion regarding the goodwill associated with the Norfolk transaction is available in Note 4 to Hydro One Networks Inc. Distribution Business' 2015 Financial Statements, which is filed as Exhibit A-06-02, Attachment 2 in EB-2017-0049. The Haldimand and Woodstock Goodwill discussion is available in Note 4 to Hydro One Networks Inc. Distribution Business' 2016 Financial Statements, which is filed as Exhibit A-06-02, Attachment 3 in EB-2017-0049.

1.2 ORILLIA POWER DISTRIBUTION CORPORATION AND PETERBOROUGH DISTRIBUTION INC.

On April 30, 2020 the OEB approved Hydro One Inc.'s purchase of the shares of Orillia Power Distribution Corporation (OPDC), [4] as well as the purchase of assets of Peterborough Distribution Inc. (PDI).[5] The shares of OPDC were purchased on September 1, 2020 and the assets of PDI on August 1, 2020. Both of these entities' assets were integrated into Hydro One's distribution system on June 1, 2021.

As the OEB approved a ten-year deferral period for Orillia and Peterborough, the rebasing of these two service areas will not take place until 2031.

1.3 HYDRO ONE SAULT STE MARIE LIMITED PARTNERSHIP (HOSSM)

In 2016, the OEB approved Hydro One Inc.'s acquisition of Great Lakes Power Transmission Inc. (GLPT). GLPT is the general partner of Great Lakes Power Transmission LP (GLPTLP) and the acquisition enabled Hydro One to acquire the various entities that own and control GLPTLP. Following the acquisition, a name change took place to rename GLPT and GLPTLP to Hydro One Sault Ste. Marie Inc. and Hydro One Sault Ste. Marie Limited Partnership respectively.

Hydro One Sault Ste. Marie Limited Partnership's (HOSSM) deferred rebasing period continues until the end of 2026, one year before the end of the JRAP period. Before the end of HOSSM's deferred rebasing period Hydro One will seek approval for an appropriate regulatory approach to reflect a rebasing of HOSSM for 2027. Such an approach will respect the completion of the deferred rebasing period, consider customer interests and benefits, and bridge the end of HOSSM's deferred rebasing period and the commencement of a new rate period for Hydro One in 2028, which will include Hydro One and HOSSM on a combined basis.

[4] EB-2018-0270, Decision and Order
[5] EB-2018-0242, Decision and Order

This page left blank intentionally.

DRAFT ISSUES LIST

1.0 GENERAL

1. Has Hydro One responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous Transmission and Distribution rate proceedings?
2. Are all elements of the proposed Transmission and Distribution revenue requirements 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?
4. Does Hydro One's investment planning process consider appropriate planning criteria and adequately address the condition of system assets?

2.0 CUSTOM APPLICATION

5. Are all components of Hydro One's proposed Transmission and Distribution Custom Incentive Rate Methodologies appropriate?

3.0 TRANSMISSION SYSTEM PLAN

6. Does the Transmission System Plan adequately address customer needs and preferences?
7. Are the proposed Transmission capital expenditures appropriate?
8. Is the Transmission benchmarking evidence sufficient?

4.0 DISTRIBUTION SYSTEM PLAN

9. Does the Distribution System Plan adequately address customer needs and preferences?
10. Are the proposed Distribution capital expenditures appropriate?
11. Is the Distribution benchmarking evidence sufficient?

5.0 GENERAL PLANT SYSTEM PLAN

12. Does the General Plant System Plan adequately address customer needs and preferences?
13. Are the proposed General Plant capital expenditures appropriate?
14. Is the General Plant benchmarking evidence sufficient?
15. Are the methodologies used to allocate Common Corporate capital expenditures to the Transmission and Distribution businesses and to determine the Overhead Capitalization Rates for the Transmission and Distribution businesses appropriate?

6.0 PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCORECARD

16. Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its Transmission and Distribution operations?
17. Are the metrics in the proposed Transmission and Distribution scorecards appropriate?

7.0 OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

18. Are the proposed Transmission OM&A spending levels appropriate?
19. Are the proposed Distribution OM&A spending levels appropriate?
20. Are the methodologies used to allocate Common Corporate OM&A Costs and Other OM&A costs to the Transmission and Distribution businesses appropriate?
21. Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?
22. Is Hydro One’s proposed depreciation expense appropriate?

8.0 RATE BASE & COST OF CAPITAL

23. Are the amounts proposed for the Transmission and Distribution rate bases and the proposed capital structures for the Transmission and Distribution businesses reasonable?
24. Are the inputs used to determine the working capital component of the Transmission and Distribution rate bases appropriate?
25. Is the forecast of long term debt for Transmission and Distribution appropriate?

9.0 LOAD FORECAST

26. Are the load forecast methodologies and the resulting load forecasts appropriate for each of Transmission and Distribution?

10.0 DEFERRAL/VARIANCE ACCOUNTS

27. Are the proposed amounts for disposition, and the continuance or discontinuation of Hydro One's existing deferral and variance accounts for each of Transmission and Distribution appropriate?
28. Are the proposed new or modified Transmission and Distribution deferral and variance accounts appropriate?

11.0 COST ALLOCATION FOR TRANSMISSION

29. Is the proposed Transmission cost allocation appropriate?

12.0 COST ALLOCATION AND RATE DESIGN FOR DISTRIBUTION

30. Is the proposed Distribution cost allocation appropriate?
31. Is the proposed Distribution rate design appropriate?
32. Are the proposed billing determinants appropriate?
33. Are the proposed revenue-to-cost ratios for all rate classes over the test period appropriate?
34. Are the proposed Retail Transmission Service Rates appropriate?

35. Is the rate harmonization proposal for the Acquired Utilities (Norfolk, Haldimand and Woodstock) appropriate?

13.0 OTHER CHARGES AND REVENUES

36. Are the proposed Export Transmission Service Rate of $1.85/MWh? (Transmission)
37. Are Other Revenue forecasts for each of Transmission and Distribution appropriate (including export revenue for Transmission)?
38. Are the proposed Specific Service Charges appropriate? (Distribution)

WITNESS LIST

Witnesses are listed in the footer of each exhibit. The final list of witnesses will be provided in advance of the oral hearing in this proceeding.

This page left blank intentionally.

CURRICULA VITAE

Curricula Vitae information will be filed prior to the oral hearing.

This page left blank intentionally.